RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

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March 24, 2020

FERC Proposes Increased Tx Incentives

Focus on Project Benefits, Not Difficulties

By Rich Heidorn Jr.

FERC on Thursday proposed a new approach to awarding transmission incentives and a doubling of the adder for participating in an RTO.

The Notice of Proposed Rulemaking would shift from awarding benefits based on the risks and challenges of a project to one focused on economic and reliability benefits (*RM20-10*).

FERC, which gained authority to issue incentives in the Energy Policy Act of 2005, implemented its policy in *Order 679* in 2006. Last March, it opened a docket to reconsider its policy (PL19-3). (*See Stakeholders Spar in FERC Tx Incentives Docket*.)

Thursday's NOPR would eliminate Order 679's "nexus test," which requires applicants to show a connection between the requested incentives and the risks and challenges of the project.

"By shifting our focus to incentives based on how a transmission project benefits consumers rather than risks and challenges of building it, I think what this NOPR does is better align our policies with the law," Chairman Neil Chatterjee said in a news conference Thursday.

The NOPR would:

- Double the incentive for joining and remaining a member of an RTO, ISO "or other Commission-approved transmission organization" to 100 basis points from 50. The incentive would be available whether or not participation is voluntary.
- Provide 50 basis points to projects that meet a pre-construction benefit-to-cost ratio in the top 25% of projects examined over a sample period, with another 50 basis points for projects that meet a post-construction b/c ratio in the top 10% of projects over the same period.
- Award up to 50 basis points to projects that

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MOPR May Not be Death Knell for Renewables in PJM

IMM: MOPR Won't Impact Next BRA Prices

By Rich Heidorn Jr.

Wind farm near Altoona, Pa. | © *RTO Insider*

PJM's expanded minimum offer price rule (MOPR) won't hinder renewables as much as some had feared if the RTO's interpretation of FERC's Dec. 19 order is accepted by the commission, according to solar and wind trade groups and a new analysis by the Independent Market Monitor.

The Monitor released an *analysis* Friday that concluded that expanding the MOPR will not have an impact on clearing prices or auction revenues for the next Base Residual Auction, for delivery year 2022/23. That came after the American Wind Energy Association (AWEA) and the Solar Energy Industries Association issued upbeat reviews of PJM's compliance filing Wednesday. (See *PJM Makes MOPR Compliance Filing*.)

FERC ordered PJM to expand the MOPR to all new state-subsidized resources, including nuclear plants and renewables. AWEA was among numerous critics of the ruling, saying

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FERC, RTOs RESPOND TO COVID-19

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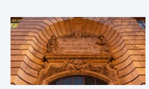

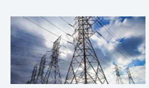

10837 Deborah Drive ▪ Potomac, MD 20854 ▪ (301) 299-0375 ▪ info@rtoinsider.com
▪ www.rtoinsider.com ▪

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CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr. 202-577-9221

Deputy Editor / Senior Correspondent
Robert Mullin 503-715-6901

Art Director
Mitchell Parizer 718-613-9388

Associate Editor / D.C. Correspondent
Michael Brooks 301-922-7687

Associate Editor
Shawn McFarland 570-856-6738

CAISO/West Correspondent
Hudson Sangree 916-747-3595

ISO-NE/NYISO Correspondent
Michael Kuser 802-681-5581

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Michael Yoder 717-344-4989

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

NERC/ERO Correspondent
Holden Mann 205-370-7844

Subscriptions

Chief Operating Officer / Co-Publisher
Merry Eisner 240-401-7399

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Marketing Director
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RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

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In this week's issue

Study: Retail Design Key to Escaping Capacity Markets

Retail-choice States Fail on Resource Procurement

By Rich Heidorn Jr.

Retail-choice states wanting to reduce their reliance on RTO capacity markets need to improve how their retail markets handle resource procurement, according to a new *study* produced for the *Wind Solar Alliance*.

Rob Gramlich, Grid Strategies | © *RTO Insider*

"When competitive retail states restructured, there was insufficient focus on designing the market structure to support long-term contracting," said the study, authored by Rob Gramlich of Grid Strategies and Frank Lacey of Electric Advisors Consulting. "Expansion of renewable energy and issues with wholesale capacity markets now require a focus on the competitive retail entities' incentive and ability to procure power."

The report notes that at least five states — all of which have retail competition — have begun proceedings over the last year to consider leaving FERC-regulated capacity markets.

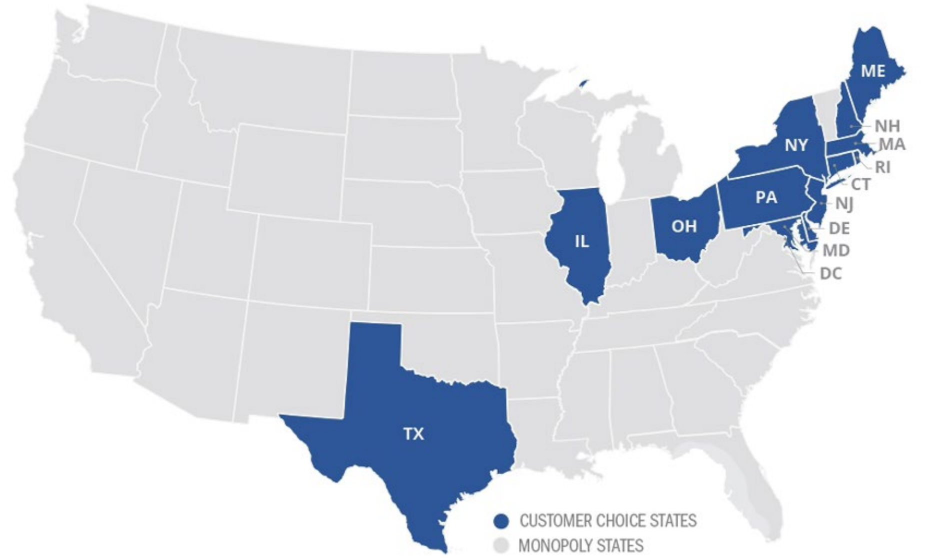
New York regulators opened a proceeding last year to determine whether NYISO's resource adequacy programs are compatible with the state's renewable energy and carbon emission-reduction goals (*19-E-0530*). (See *NYPSC Opens Resource Adequacy Proceeding*.)

Connecticut regulators held a public hearing in January on whether ISO-NE's wholesale electricity markets are geared to serving the state's clean energy objectives. (See *Connecticut Weighs Pros, Cons of ISO-NE Markets*.)

In New Jersey, Illinois and Maryland, regulators and legislators are considering leaving PJM's capacity market because of the expansion of the minimum price offer rule (MOPR) to state-subsidized generation. (See *PJM's MOPR Quandary: Should States Stay or Should they Go?*)

Frank Lacey, Electric Advisors Consulting | © *RTO Insider*

"If states wish to rely less on capacity markets, they will need to make sure their retail markets are designed to handle resource procurement," the study said. Yet among the 14 states with retail competition, only Texas clearly assigns responsibility for resource procurement to customers or their load-serving entities. "No entity in those [13 states] has both the incentive and ability to procure power, given the rules and structures currently in place," Gramlich and Lacey say.



Of the 14 states with retail electric choice, only Texas clearly assigns responsibility for resource procurement to customers or their load-serving entities. | *Wind Solar Alliance*

The other 13 states have "hybrid" competitive retail structures with "a monopoly default service provider offering rates that are subsidized to varying degrees and some form of a free option for customers to move in and out of competitive service. This dynamic reduces the incentive for retailers to procure supply."

Clean Energy Transformation

The study says the transition to a decarbonized economy will require a market structure with entities able and willing to sign long-term contracts because generation developers and lenders are reluctant to finance 20- to 40-year assets based on expected future hourly prices.

This is especially the case for renewables, which are capital-intensive, with no fuel expenses and minimal ongoing costs. "Prearranged contracts provide the certainty necessary to finance those capital costs at a reasonable rate before the investment is made," said the authors, who also noted that increasing penetration of renewables with zero production costs can depress spot energy prices. "Contracts provide upfront revenue certainty for lenders prior to committing capital."

The failure of most restructured states to assign responsibility for ensuring resource adequacy caused a "free-rider" problem, leaving supply "under-procured and underpaid," the authors say. "That is one reason RTOs in those areas stepped into the resource adequacy role with mandatory capacity markets."

Recommendations

The study includes a scorecard on state retail market rules and their impact on competitive retail energy providers' incentive to invest in generation resources. Texas gets straight "A's," while New Jersey, Maryland and Pennsylvania score mostly "D's" and "F's".

The report identifies several reforms the authors say would improve retail market operations:

- **Eliminate Subsidies for Default Service:** Utilities typically do not include in default service rates the costs for billing systems, accounting services, call centers or other functions required to deliver default service, resulting in a subsidy the authors estimate to be about 1 to 2 cents/kWh. In Baltimore Gas and Electric's 2019 rate case, for example, the cost of providing default service was estimated to be about $170 million, only $12.3 million of which BGE planned to allocate to default service customers. The remainder was recovered through BGE's distribution rates, which are paid by all customers, including those choosing competitive suppliers.
- **Unbiased Initial Placement:** Default service is really a "provider of first resort" in many states instead of the "provider of last resort" as it is sometimes referred, the authors say, noting that only about one-third of residential customers in the 13 states have chosen competitive suppliers. Retail electric provid-

ers' (REPs) "ability to maintain their customer base is eroded where new customers or moving customers are automatically placed on utility default service," the authors say. "If customers were compelled to choose a supplier when enrolled for new service, they would be empowered with many options, including the option to purchase renewable energy."

- **No Free Option:** Consumers in hybrid restructured states are free to return to default service at any time. "The option imposes costs on default service wholesale providers (they lose load when market prices decline because the default service price decline lags the market) and onto REPs and onto other entities that provide customer services. (REPs lose load to default service when market prices increase because the default service price increase lags the market.) The free option eliminates the incentive for REPs to procure power on a long-term basis on a customer's behalf."
- **Creditworthiness:** High and enforceable creditworthiness standards are needed to ensure REPs can make the long-term resource commitments needed to serve their loads.
- **Utility Neutrality on Default Service:** Utilities profiting from providing default service are likely to steer customers away from competitive suppliers, the authors say. In its latest distribution rate proceeding, it was estimated that BGE will earn $8.3 million annually above its approved distribution revenue requirement from providing default service. By contrast, Texas has eliminated utilities' role as default service provider.

	NEW JERSEY	MARYLAND	PENNSYLVANIA	TEXAS
Market Reflective Default Service Pricing	F	D	D	A
Unbiased Initial Placement	F	F	F	A
Stable Market Size	F	F	D	A
Non-discriminatory Rate Design	F	F	F	A
REP Billing	F	C+	D	A
Creditworthiness	D	D	D	A
Utility Neutrality from Default Service	C	F	C	A
Regulatory Risk	A	D	B	A
Long-term Customer Relationships	D	C	D	A
Move-in/Move-out Bias	F	F	F	A

State retail market rules were graded for their impact on competitive retail energy providers' incentive to invest in generation resources. | *Wind Solar Alliance*

The report says the recommendations would "enable broader wholesale market improvements."

"One key market design element that is not widely used yet but is important to ensure retail providers have the incentive to sign long-term contracts, as well as to provide appropriate long- and short-term incentives for efficient behavior, is to accurately price energy at times of scarcity," the authors say. "In Texas, prices can rise to $9,000/MWh at these times, as they did in the summer of 2019. This feature along with the rest of the Texas structure appears to be working to achieve supply-demand balance." ■

FERC/Federal News

FERC Proposes Increased Tx Incentives

Focus on Project Benefits, Not Difficulties

Continued from page 1

show reliability benefits through quantitative or qualitative analysis.

- Award 100 basis points for transmission technologies that "enhance reliability, efficiency and capacity as well as improve the operation of new or existing transmission facilities."
- Replace the current limits on incentives to the base return on equity zone of reasonableness with a 250-basis-point cap on total ROE incentives. It also seeks comment on whether transmission providers should be allowed to replace the zone-of-reasonableness restrictions on previously granted incentives with the hard 250-bp cap.
- Eliminate incentives for transmission facilities built by stand-alone transmission companies or "transcos."
- Retain existing incentives for abandoned plant recovery, construction work in progress and hypothetical capital structures.

Partial Dissent

Commissioner Richard Glick dissented in part, saying the NOPR "focuses narrowly on the transmission needs of today and will do little to help the country build the transmission grid of the future.

"I am concerned that [FERC's proposal] altogether ignores transmission projects needed to meet public policy goals, such as state carbon reduction targets, which are the country's most pressing transmission need," he said, adding that the commission proposed the 250-bp cap "without any evidence to suggest that transmission owner rates would be just and reasonable" with the adder.

Glick said the increase in the RTO incentive ignores Congress' direction that the incentive is supposed to be for joining an RTO, not remaining in one. "Even worse, the NOPR proposes to double the size of this incentive from 50 basis points to 100 basis points — even though there is nothing in the record to suggest that any transmission owner would leave an RTO if not for that handout," he said in a statement. "Simply put, the commission wants to double the cost to consumers of an 'incentive' that does not incentivize anything."

Chatterjee insisted he shares Glick's belief that increased transmission is essential to decarbonization efforts, differing only on how to accomplish the goal. He also defended the increased RTO adder, saying RTOs/ISOs provide annual benefits exceeding $10 billion. "Those benefits continue to increase as the RTOs/ISOs evolve. Nationwide, the cost of this incentive is a fraction of these benefits. But I also think there [are] increasing challenges to TO participation in the RTOs and ISOs."

The commission also issued a final rule clarifying its filing instructions for form FERC-730, which must be filed annually by utilities receiving transmission incentives (*RM20-11*). The clarification was requested by the Office of Management and Budget (OMB) to comply with the Administrative Procedure Act and the Paperwork Reduction Act of 1995 (PRA).

Comments on the NOPR are due 90 days after publication in the *Federal Register*. ■

| *Burns & McDonnell*

FERC/Federal News

FERC Relaxing Deadlines, Enforcement

By Rich Heidorn Jr.

FERC Chairman Neil Chatterjee | © *RTO Insider*

FERC Chairman Neil Chatterjee said Thursday the agency is relaxing some filing deadlines and deferring some enforcement activities in response to the COVID-19 coronavirus pandemic, but that commission staff are working remotely to continue responding to industry filings.

"This commission will not be in the business of second guessing the good faith actions that companies take to keep the lights on," Chatterjee said at a news conference via phone after the commission canceled its March open meeting. "I'm committed to ensuring that the industry can focus on continuity, safety and stability — not regulatory or enforcement matters that are not mission-critical during this crisis."

The commission announced that:

- It has issued a notice extending the deadlines for certain filings that are due on or before May 1, 2020 (*AD20-11*). Included in the extension are filings required by entities' tariffs or rate schedules and non-statutory filings required by the commission such as compliance filings, responses to deficiency letters and rulemaking comments. Deadlines for certain forms required by the commission also have been relaxed, except for FERC Form 6, the annual report of oil pipelines. The notice also indicates that entities may seek extensions for other deadlines and waivers of commission orders, regulations, tariffs and rate schedules.
- FERC's Office of Enforcement is postponing all previously scheduled audit site visits and investigative testimony. The office also will consider extensions and waivers of compliance filings, forms and electronic quarterly reports.
- Technical conferences scheduled through May 2020 will be postponed or conducted via conference call or WebEx. Schedules will be posted to the FERC.gov calendar.
- Chief Administrative Law Judge (ALJ) Carmen Cintron has postponed a hearing scheduled to start April 7 and will make case-specific calls on other hearings as their start dates approach. ALJ settlement conferences will continue via conference call.
- Chatterjee has tapped Caroline Wozniak, senior policy adviser in the Office of Energy Market Regulation, as the commission's point of contact for all industry inquiries on the impact of its COVID-19 response. Questions can be sent to *PandemicLiaison@ferc.gov*.

Chatterjee said the commission is working with the Department of Energy, Department of Homeland Security and the Centers for Disease Control and Prevention to address coronavirus impacts affecting energy infrastructure. It also is working with NERC's Electricity Information Sharing and Analysis Center to provide recommendations to industry to help with business continuity planning.

The steps announced Thursday followed a joint pledge by FERC and NERC Wednesday to use "regulatory discretion" to address the difficulties registered entities may have with complying with reliability standards. (See *FERC, NERC Relax Compliance in Light of COVID-19*.)

Most commission employees are on telework status until further notice and headquarters will remain closed to outside visitors unless they are cleared by the Office of the Executive Director.

Although the commission canceled Thursday's open meeting, it said it would issue all the *orders* listed on the meeting agenda through notational voting.

Chatterjee said the commission's telework capabilities should enable it to continue to perform its duties.

"I think that one of the reasons we wanted to hold this teleconference and vote on all of the orders that were on the [agenda] notationally today was to demonstrate that the commission is fully functioning," he said.

Commissioner Richard Glick suggested in a statement that the commission should delay issuing nonessential orders because it has no authority to waive the 30-day deadline for parties to seek rehearing on commission orders. "To the extent commission action is not statutorily required or needed in the short-term, I believe we should refrain from acting to allow parties who are otherwise dealing with the pandemic to avoid putting resources toward seeking rehearing of a commission order," he said.

Chatterjee said that would be unfair to parties who have been waiting for commission action.

"The industry continues to work to provide Americans with energy. The commission has to continue to respond to their filings. Many of the commission's actions are increasing regulatory certainty to stakeholders. We're not imposing additional burdens. … The energy bar should largely be able to telework as is most of the commission.

"Of course, we'll be flexible and evaluate all of our actions on a case-by-case basis," he added. "But I think FERC pausing action right now would not be good for the economy. The last thing industry needs right now is delays."

Jordan Cove, Danly

Among the items on which the commission acted Thursday was voting 2-1 to approve the Jordan Cove LNG export facility, with Glick dissenting (*CP17-495, CP17-494*). A vote on the project was postponed at the last minute at the commission's February meeting. (See *In Rare Surprise, FERC Declines to Act on Jordan Cove*.)

Chatterjee said he was deferring to General Counsel James Danly on when he would be sworn in as FERC's fourth commissioner. Danly was confirmed by the Senate on March 12. (See *Senate Confirms Danly to FERC*.)

"Until he makes that announcement, he is still general counsel," Chatterjee said, declining to say who would be Danly's replacement as the commission's top lawyer.

Chatterjee rejected complaints by Democrats on the Senate Energy and Natural Resources Committee earlier this month that the commission had become politicized. Democrats were incensed that Republicans advanced Danly without taking action on their candidate for a Democratic opening on the five-member commission. (See *Danly Re-advances, but not Without Drama*.)

Danly, Chatterjee and Commissioner Bernard McNamee will form a 3-1 majority, with Glick the lone Democrat.

"The overwhelming majority of the work we do is by consensus. It shouldn't matter what political party there is," Chatterjee said. "I do not recall similar criticism of the commission when it was 3-0 Democrat for a considerable period of time." ■

FERC/Federal News

Gas, Renewables Pushed Power Prices Down in 2019

FERC Markets Report Sees Storage 'Sea Change'

By Rich Heidorn Jr.

Lower natural gas prices and increased renewable penetration pushed wholesale power prices down sharply in most of the country last year, FERC reported last week.

The commission's 2019 State of the Markets *report* noted that prices dropped 20% to 30% in MISO, PJM, NYISO and ISO-NE compared with 2018. Prices in northern CAISO were down 10%, and those in southern CAISO down 20%.

SPP's prices were the lowest of the organized markets, averaging $30.43/MWh, unchanged from a year before, according to the report by the Office of Energy Policy and Innovation's Division of Energy Market Assessments (DEMA).

Only ERCOT saw an increase, as record-high demand in summer pushed prices for the year to $49.65/MWh, up 20%.

Natural Gas

Although natural gas demand hit new highs, record-high production and relatively mild weather resulted in price declines of 35% to 41% at hubs in the Mid-Atlantic, New England and New York City. The biggest drops were in the Southwest, where hubs traded at negative prices at times because of pipeline takeaway capacity constraints.

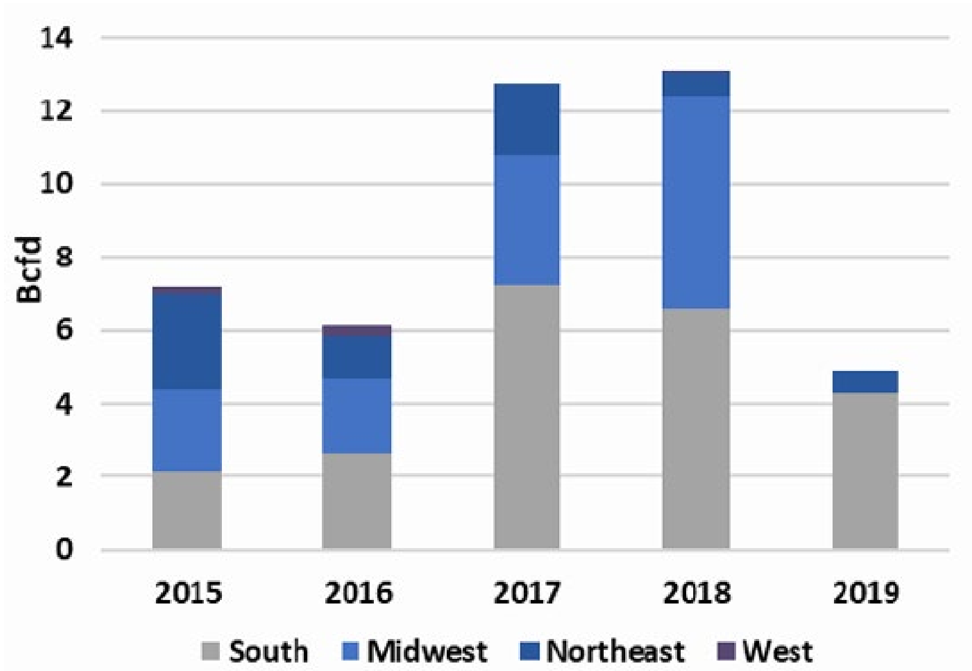
U.S. natural gas production rose to 92.2 billion cubic feet per day (Bcfd) in 2019, up 8.4 Bcfd, the second-largest increase since the advent of shale exploration. Net gas exports averaged 5.1 Bcfd through November 2019, up from 1.9 Bcfd in 2018.

Natural gas shippers added nearly 5 Bcfd (17 miles) of commission-jurisdictional pipeline capacity in 2019, down from the 13 Bcfd added in 2018.

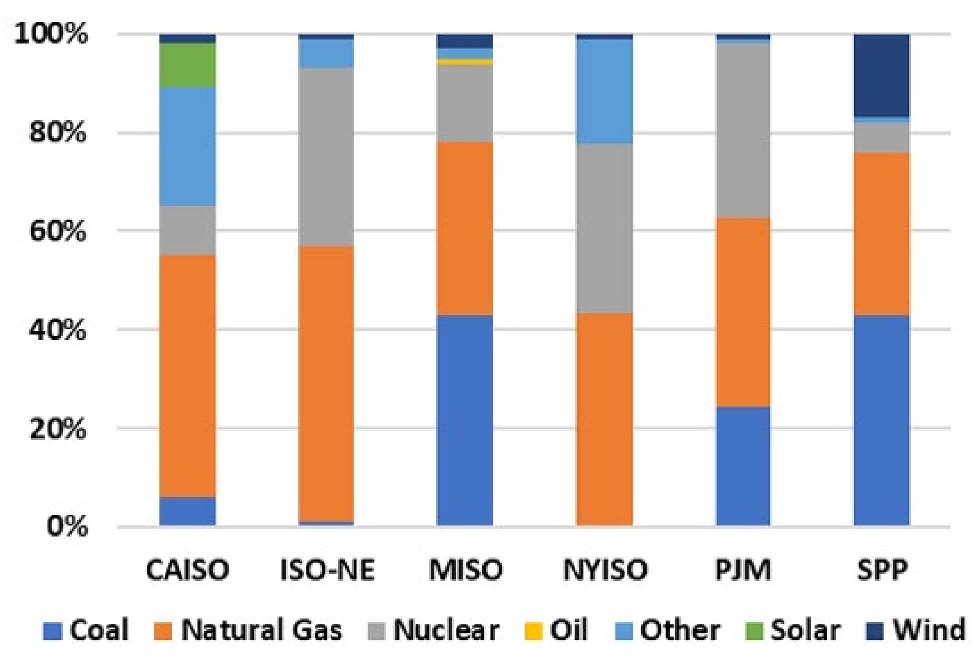
Overall natural gas demand increased 2.6 Bcfd to 84.9 Bcfd in 2019, a 3% jump. Demand for electric generation averaged 30.9 Bcfd, up 7%, with a 12% increase in the Midwest.

Fuel Mix

Natural gas was responsible for 42% of generation nationwide between January and November 2019, according to the Energy Information Administration (EIA), with 26% from coal, 22% from nuclear, 4% from wind and 1%



U.S. natural gas pipeline in-service capacity additions by region (Bcfd) | *FERC Office of Energy Projects*



Generation by fuel type | *ABB Velocity Suite*

FERC/Federal News

from solar.

MISO and SPP were most dependent on coal, which accounted for 43% of the regions' generation. Solar and wind were big contributors in CAISO and SPP, respectively.

As in recent years, most new generation was natural gas or renewables and most retirements were coal plants.

The biggest retirements were the 670-MW Pilgrim Nuclear Power plant in ISO-NE (May 2019) and the 980-MW Three Mile Island nuclear power plant in PJM (September 2019).

PJM added 356 MW of natural gas-fired capacity, mostly combined cycle units. MISO saw a net decrease of 852 MW as it lost 2.9 GW of coal-fired capacity and gained 969 MW of natural gas and 997 MW of wind capacity.

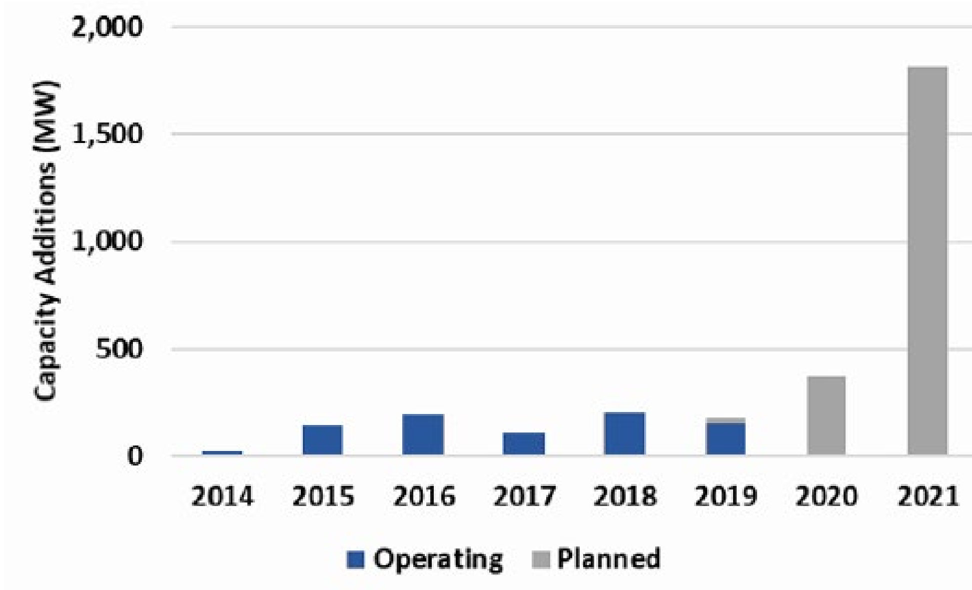
SPP added 1.8 GW of wind capacity and had no retirements in 2019.

CAISO's capacity dropped by 21 MW, losing 600 MW of natural gas capacity and adding 561 MW of solar.

Storage, DERs

Battery storage capacity increased by 174 MW in 2019, down from a 202-MW boost in 2018. But EIA forecasts about 400 MW of new battery storage will be added in 2020 and 1,816 MW in 2021.

"While it is unlikely all planned facilities will be operational by the end of 2021, the large increase represents a sea change in the role that battery storage plays in the bulk power system," FERC said.



Battery storage capacity additions in recent years | *EIA Form 860M*

Battery storage additions have been clustered in a few states, led by California with 38% percent of planned capacity through 2023.

Capacity from distributed energy resources using net metering rose 4 GW to a record 23 GW in 2019, most of it in California, New Jersey, Massachusetts, Arizona and New York. The five states represent 70% of the net-metered capacity in the country, including California's 40% share.

All but 6% of net metered capacity is solar PV. Solar PV's price dropped 37% between 2013 and 2017, FERC said.

Transmission

Order 1000 transmission planning regions had 309 transmission projects go into service during the year, led by MISO (104) and PJM (101). In 2019, PJM, ISO-NE and NYISO each announced, or awarded to developers, new transmission projects using the competitive bidding processes in Order 1000. ■

Transmission Planning Region	Number of Projects
Columbia Grid	4
Columbia Grid Non-Enrolled Members	3
Florida Reliability Coordinating Council	4
ISO New England (ISO-NE)	20
Midcontinent ISO (MISO)	104
New York ISO (NYISO)	5
Northern Tier Transmission Group	1
PJM Interconnection (PJM)	101
Southeastern Regional Transmission Planning Region	28
Southwest Power Pool (SPP)	13
WestConnect	7
TOTAL	**309**

Transmission additions by transmission planning region | *C Three Group*

CAISO/West News

PG&E Deal with Gov. Would Allow Utility's Sale

Newsom to Drop Objections Under Agreement

By Hudson Sangree

Pacific Gas and Electric has cleared another hurdle in its bid to exit bankruptcy, but the latest comes with a caveat: If the company can't win court approval of its Chapter 11 reorganization plan by June 30, the state or a third-party bidder could buy the utility under a fast-track process outlined Friday.

PG&E, headquartered in San Francisco, was incorporated 115 years ago.

The sale process will "be implemented in the unlikely event the debtors fail to meet certain dates regarding the administration of these Chapter 11 cases," PG&E said in a *motion* filed with the U.S. Bankruptcy Court in San Francisco, seeking rapid approval of its "case resolution contingency process."

The plan is part of a deal the company struck last week with Gov. Gavin Newsom, under which Newsom dropped his objections to PG&E's bankruptcy proposal in exchange for a series of concessions.

In addition to agreeing to sell itself, PG&E said that it would allow a state-appointed observer to monitor its safety operations until it exits bankruptcy and that it would refrain from paying shareholder dividends over the next three years.

On March 13, the state's largest utility largely *agreed* to greater oversight by the California Public Utilities Commission and a process of escalating enforcement that could result in PG&E losing its electric monopoly — its certificate of public convenience and necessity — in extreme circumstances. (See *CPUC President Wants More Control over PG&E*.)

Gov. Gavin Newsom has been a staunch critic of PG&E in recent months.

Newsom's opposition to PG&E's plan to issue billions of dollars in new debt and equity appeared to be one of the last major obstacles to PG&E leaving bankruptcy by June 30. That is the deadline for PG&E to participate in a state wildfire insurance fund created by Assembly Bill 1054, a measure Newsom pushed through the legislature last July.

Wildfire victims and other stakeholders must still vote on PG&E's bankruptcy plan, and the CPUC must approve it under an *investigation* it opened in September.

PG&E filed for bankruptcy protection in January 2019 after a series of devastating wildfires in 2017 and 2018 saddled it with billions of dollars in liabilities to those who lost family members, homes and businesses.

Its stock plummeted from more than $46/share in October 2018 to $7.23/share immediately after it filed for bankruptcy. PG&E's share price has been on a roller coaster since, and the stock market meltdown caused by the COVID-19 coronavirus outbreak sent its stock from $17.92/share on Feb. 21 back to $7.22/share on Friday.

Amid the uncertainty about its financial future, the utility is eager to resolve Newsom's concerns as quickly as possible. In its court papers filed Friday, PG&E urged federal Judge Dennis Montali to hear and approve its agreement with Newsom on April 1.

"Approval of the case resolution contingency process will facilitate the debtors' ability to timely exit these Chapter 11 cases, provide a positive signal to the financing markets and further solidify support for the plan and the likelihood of a smooth and largely consensual resolution of these Chapter 11 cases," the utility's lawyers said.

Montali, however, disagreed that the matter was as urgent as PG&E contended. In an *order* signed Friday, he set April 7 as the hearing date.

"The relief requested ... does not appear to require imminent action by the debtors, the CPUC, the governor's office or others," the judge wrote. "[N]othing suggests that the governor's office insisted on court approval as quickly as debtors request."

The hearing will be conducted by telephone because the federal courthouse in San Francisco is closed due to the virus, Montali noted. The health crisis justifies giving opponents additional time to file briefs and not to rush things at PG&E's insistence, he said.

"The world-wide coronavirus pandemic is reason enough [to] make sure there is sufficient cause to act so quickly," the judge said. ■

CAISO/West News

FERC Rejects Rehearing on CAISO Incentive Adder

Insists ISO Participation is Voluntary

By Hudson Sangree

FERC said March 17 it won't rehear a case on whether Pacific Gas and Electric deserves a $30 million annual incentive adder for staying in CAISO (*ER14-2529-006, ER15-2294-005, ER16-2320-005*).

The commission first decided the hotly contested case in August 2018 and reaffirmed its decision in July after the 9th U.S. Circuit Court of Appeals rebuked it and sent the matter back on remand. (See *PG&E Deserves $30M ISO Adder, FERC Says*.)

The two decisions left little doubt about FERC's views on whether participation in CAISO is voluntary or mandatory for PG&E and other transmission owners.

FERC concluded in both instances that participation in CAISO is voluntary; that PG&E could unilaterally leave CAISO without permission from state regulators; and that the "RTO-participation incentive [adder] induces PG&E to remain a participating member of CAISO and is consistent with the directives of the Federal Power Act." (See *Can PG&E Quit CAISO? FERC Wants to Know*.)

The California Public Utilities Commission and other parties sought a rehearing, contending FERC had cited irrelevant sections of state law and ignored court decisions regarding the scope of the CPUC's authority. They also argued FERC had erroneously justified the grant of the incentive adder based on commission policy that participation in a transmission organization is voluntary, even if state law and regulations say it's not.

"We are unpersuaded by these arguments," FERC said in its latest ruling. The commission said it had interpreted the appropriate laws and legal precedents correctly and that it didn't have to defer to the CPUC's authority in the case.

The CPUC argued in its rehearing request that it must approve changes in operational control of utility assets, such as CAISO returning operational control of PG&E's transmission lines to the utility. FERC said it didn't need to address that argument because it was based on evidence presented for the first time on rehearing.

"Nonetheless, we disagree with California parties' interpretation," FERC said. California law "expressly provides for CPUC authority over 'changes in control' of a public utility, along with mergers and acquisition." The specified code sections, FERC said, "are most reasonably interpreted to mean changes in ownership control of the entire utility enterprise, not the operational control of individual facilities."

The state laws cited by the CPUC refer to "changes or transfers in proprietary interests or something similar, rather than applying to transfers of operational control where the transmission owner retained ownership over the transmission facilities," as in the case of PG&E and CAISO, FERC said. ■

| *PG&E*

CAISO/West News

California Agencies, Utilities Amp Up Virus Response

By Hudson Sangree

SACRAMENTO, Calif. — California's grid operator, government agencies and utilities bolstered actions this week to prevent the spread of COVID-19, in keeping with the state's increasing limits on residents and businesses.

CAISO said March 17 it would extend its ban on in-person meetings at its Folsom headquarters until at least May 1. The ISO previously established the restriction through April 1 to protect its employees and prevent operational disruptions. (See *RTOs Take Steps to Address COVID-19's Spread*.)

"These measures, part of our pandemic response plan, are intended to protect our staff, customers, stakeholders and our community, and to fulfill our critical mission to reliably operate the grid, as important as ever during these trying times," CEO Steve Berberich said in a statement.

CAISO plans to host meetings via teleconferencing and webinars. It suspended non-essential business travel for its employees and stopped tours of its facilities.

"To maintain reliability of electricity transmission, critical staff essential to the ISO's core business services, such as grid operators, continue to work at the ISO control centers, and the coronavirus developments have had no impact to the system or markets," CAISO said.

California Energy Commission Chair David Hochschild announced the CEC will postpone meetings that could draw more than 250 people and will provide remote participation options for all other meetings and gatherings. Many commission staff members will be teleworking at least through the end of March, he said.

In-person meetings won't be held at CAISO headquarters in Folsom, Calif., until at least May 1. | *© RTO Insider*

The California Energy Commission is postponing meetings that could draw a crowd, like its Feb. 20 session on rooftop solar. | *© RTO Insider*

"Internally, we are quickly implementing processes to minimize disruptions to the Energy Commission's workflow. Our focus is to ensure business continuity at the Energy Commission, including grant administration and invoice processing," Hochschild said in a statement.

The California Public Utilities Commission told utilities under its jurisdiction — including Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric — to stop disconnecting customers who can't pay their bills.

"In these unsettling and unprecedented times, many people are concerned about the health and safety of themselves and their loved ones, said CPUC President Marybel Batjer. "They should not also have to worry about their essential utility services being shut off for non-payment because they are unable to report to work due to illness, quarantine or social distancing."

The protections — spelled out in a *letter* from CPUC Executive Director Alice Stebbins to the electric service providers — apply retroactively to March 4, when Gov. Gavin Newsom declared a state of emergency in California. The order still must be ratified by the commission.

Some utilities, including PG&E, had already announced a voluntary moratorium on disconnections due to nonpayment. PG&E's moratorium, announced March 12, applies to both residential and commercial customers, the utility said.

The Sacramento Municipal Utility District, which also has stopped disconnecting customers who don't pay their bills, said Wednesday it was closing its buildings to the public through at least April 17 and plans to handle all customer business online and by phone.

"Most importantly though … all SMUD outage response levels remain unchanged and all functions necessary to run the power system will operate as normal," it said.

A growing number of Californians are under "shelter-in-place" orders, with residents told to stay home and avoid contact for at least the next three weeks. Seven of the San Francisco Bay Area's nine counties have issued the orders, along with counties in the Sacramento regions. Violators could be convicted of misdemeanors.

Many nonessential businesses, such as restaurants and movie theaters, have shut down, and almost all schools are closed, a condition the governor said could last through the end of the academic year.

Millions of residents staying home could alter California's typical "duck curve" of electricity demand, which peaks in the morning and evening when people are home and drops midday as solar output ramps up when they're at work and school.

A CAISO spokeswoman said Wednesday it was too soon to tell how the pandemic is affecting electricity demand, especially because the weather has been cool and rainy in recent days, but the ISO is monitoring the situation for changes in load and trends in customer demand. ■

CAISO/West News

PG&E to Plead Guilty to Killing 84 in Camp Fire

Questions Remain About Probation in Prior Felonies

By Hudson Sangree

Pacific Gas and Electric said Monday it will plead guilty to 85 felonies stemming from the Camp Fire in November 2018, including 84 charges of involuntary manslaughter, a subset of homicide involving criminally negligent behavior.

"Today's charges underscore the reality of all that was lost, and we hope that accepting those charges helps bring more certainty to the path forward so we can get victims paid fairly and quickly," CEO Bill Johnson said in a statement.

The plea deal comes days after California Gov. Gavin Newsom agreed to drop his objections to PG&E's reorganization plan with the caveat that the utility could be put up for sale if a federal bankruptcy judge doesn't approve the plan by June 30. (See *PG&E Deal with Gov. Allows for Utility's Sale*.)

The Camp Fire was the deadliest and most destructive in state history. It started when a worn C-hook on a transmission tower broke, releasing a high-voltage line that ignited dry vegetation, according to the California Department of Forestry and Fire Protection (Cal Fire).

PG&E's faulty maintenance of its century-old Caribou-Palermo line was cited as the cause of the equipment failure. (See *Cal Fire Pins Deadly Camp Fire on PG&E*.)

Within hours after ignition, flames raced through the rugged forested countryside of the Sierra Nevada foothills and into the town of Paradise, with a population of 27,000. It destroyed more than 14,000 homes and 500 businesses. The death toll from the fire was 86, Cal Fire said.

The Camp Fire tore through Paradise, Calif., on Nov. 8, 2018, killing 86 people. | *Tanner Hembree/USDA Forest Service*

One person committed suicide as flames approached, and another died from a heart attack while fleeing the blaze, law enforcement officials have said. PG&E was not charged in those deaths.

PG&E will also plead guilty to a felony count of unlawfully starting a fire with enhancements for causing great bodily injury to multiple people, for injuring firefighters and for burning numerous structures, according to the plea agreement filed by the Butte County District Attorney's Office.

The utility agreed to pay the maximum fine of nearly $3.5 million and to reimburse the prosecutor's office $500,000 for its investigation, which resulted in a grand jury indictment of PG&E, the DA's office said. PG&E has cooperated with law enforcement and accepted criminal responsibility, prosecutors said.

Nothing prevents crime victims from seeking restitution from PG&E, but the utility told the federal bankruptcy judge overseeing its Chapter 11 case that it hopes any payments will come from the $13.5 billion trust it already plans to establish to compensate wildfire victims. (See *Federal Judge to Review PG&E's Wildfire Plan*.)

PG&E filed for bankruptcy protection in January 2019 as it faced an estimated in $30 billion in liabilities from the Camp Fire and a series of devastating blazes in Northern California wine country in October 2017.

Butte County District Attorney Michael Ramsey cited PG&E's reorganization plan, which the utility is trying to have approved by the end of June, as a motivating factor for the plea deal. (See *Judge OKs PG&E's $23B Plan to Exit Bankruptcy*.)

There is a "significant risk that a further criminal prosecution of the company at this time could jeopardize the company's ability to pay victims," Ramsey wrote in his court filing. PG&E has also committed to paying local governments and agencies $1 billion, including $270 million to the town of Paradise and $252 million to Butte County, the prosecutor said.

Prior Felonies and Probation

The plea deal is still subject to approval by

CAISO/West News

state and federal courts. If that occurs, PG&E will have been found guilty of 101 felonies in the past four years.

Jurors in August 2016 convicted the utility of six felonies related to the San Bruno gas pipeline explosion in 2010, including pipeline safety violations and obstructing a federal investigator. The disaster killed eight people and burned down part of a suburban San Francisco neighborhood.

The company remains on criminal probation in the case, and new convictions could violate the terms of that probation. Federal Judge William Alsup has been a vocal critic of the utility at its probation hearings, and whether he will impose new measures remains a question.

Stanford University law Professor Robert Weisberg, an expert in white collar crime and sentencing, said Alsup could levee additional fines or place the company in receivership, but he doubts that will happen.

"This is an unusual situation," Weisberg said. "PG&E is already in so much trouble and involved in so many legal entanglements [that] the incremental effect of additional criminal convictions may not be so significant."

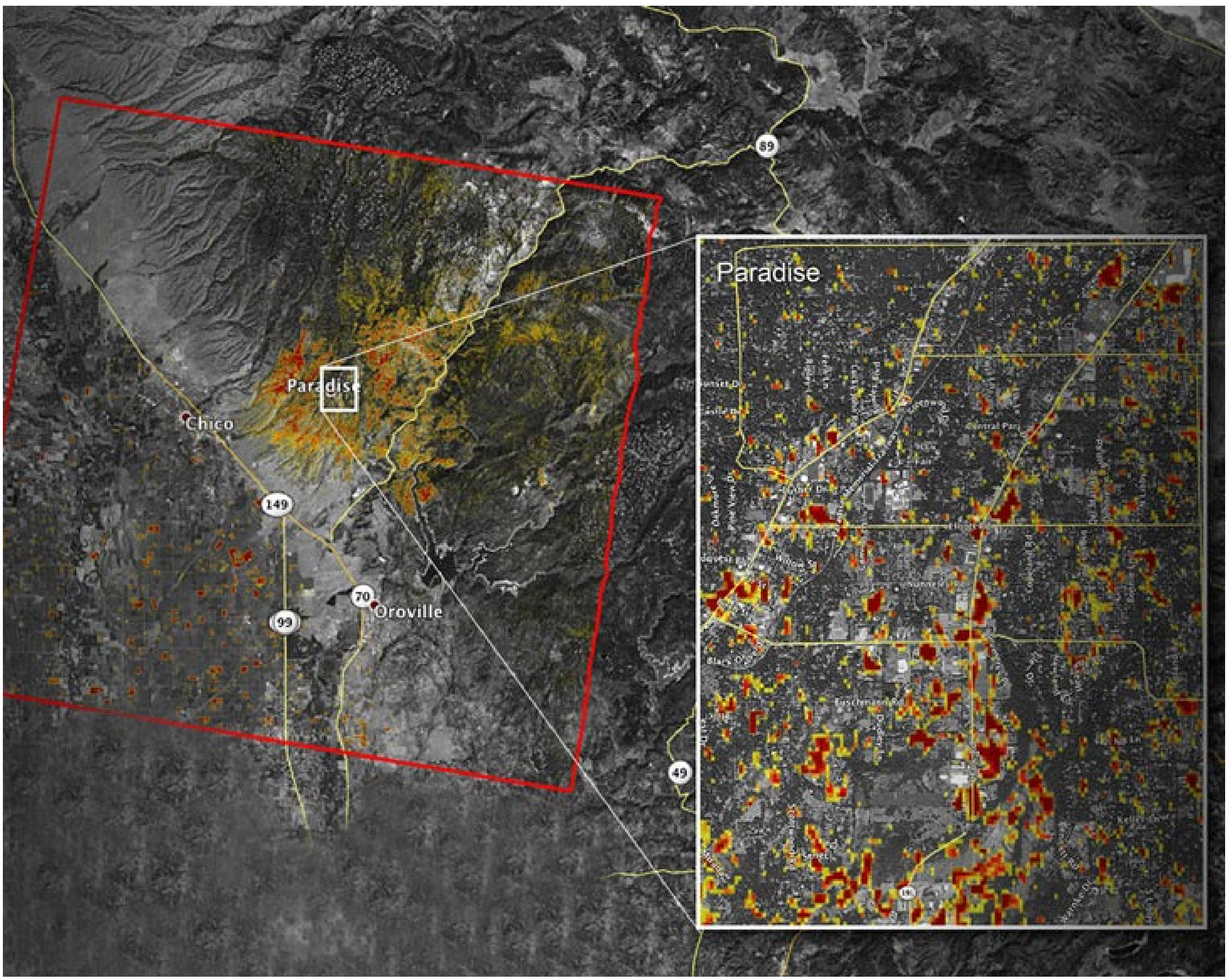
PG&E is already facing huge financial liabilities in its nearly $60 billion bankruptcy case and has agreed to stricter oversight by the California Public Utilities Commission, including the possibility of losing its electric monopoly.

The number of manslaughter charges is dramatic and may be the most homicides an American corporation has ever been charged with, he said.

Another corporation might be so stigmatized by lesser criminal convictions that it would go out of business, he said. He cited the Arthur Andersen accounting firm, brought down by its wrongdoing connected to the Enron scandal in the early 2000s, including a conviction for obstruction of justice.

PG&E is different, Weisberg said. California's largest utility is notorious for its wrongdoing over the years yet remains in business.

"Everybody now thinks of PG&E as such a feckless, pathetic entity," he said. "This may not have as much of a punch." ■



Satellite imaging showed damage from the Camp Fire. on Nov. 16, 2018. | *NASA*

ERCOT News

ERCOT, SPP Adapt to 'New Normal' in Pandemic

By Tom Kleckner

When ERCOT this week instituted mandatory work-from-home requirements for staff that do not need to be in the office to handle their job responsibilities, spokesperson Leslie Sopko quickly encountered one of the major distractions of working from home: children.

"They followed me everywhere," she said Wednesday — with a laugh — of her daughters, 7 and 4. The oldest was home from school, the youngest from daycare.

Sopko spoke from the safety of her back porch, where, armed with her laptop and cell phone, she said she could see her trees and the setting sun. It had been a day packed with responding to media inquiries and joining conference calls determining the next steps to respond to the coronavirus disease (COVID-19).

Besides ensuring employees and contractors have the proper tools and resources to do their jobs, either at ERCOT facilities or from home, the grid operator has been using a wide array of communication channels to reach staff. An internal newsletter is constantly updated with new information stressing caution and offering tips on working from home, social distancing and well-being. CEO Bill Magness has sent several well-received messages of encouragement and comfort.

"We're definitely taking as many precautionary steps as we can to keep our staff healthy and safe," Sopko said. "We've been very consistent with our communications … We have received positive feedback that they do feel informed. We know we provide a critical function, and we're dedicated to maintaining the grid's reliability."

On March 17, ERCOT *issued* "Pandemic Plan Preparations for Coronavirus (COVID-19)," which listed the steps it has taken to protect employees and ensure it continues to manage the grid. The plan also included a link to a *redacted version* of its pandemic preparedness plan.

The ISO has closed its facilities to most outside visitors since March 3, instituting travel restrictions for staff and canceling in-person meetings. Staff that need to be on-site must be on a pre-determined list and undergo temperature screenings when reporting for work. Even then, they are expected to maintain social distancing as much as possible.

Sopko said she is not aware of any confirmed cases of the virus among staff.

She said it is too early to see any change in the ISO's load patterns, as school and business closures have only recently begun. On Thursday, Texas Gov. Greg Abbott issued an executive order that will close schools, restaurants, bars and gyms as COVID-19 continues to spread.

An ERCOT operator monitors the grid in the Operations Center. | © *RTO Insider*

"We need some time to trend the data," Sopko said of potential changes in ERCOT's load patterns. "We need things to settle into the new normal, if you will."

The grid operator will announce any changes to the summer peak load forecast when it releases the summer's final resource adequacy assessment in May.

SPP Protects Operations Staff

SPP is taking similar proactive measures, "strongly encouraging" staff to work from home if they are able and scrubbing in-person meetings through April. The RTO has closed its gates and doors to all but mail and other deliveries, as well as maintenance work — and only if visitors have been screened by security.

David Kelley, SPP | © *RTO Insider*

"Pretty much everyone is working from home," said David Kelley, director of seams and market design, during a conference call Thursday with the Western Markets Executive Committee.

Spokesperson Derek Wingfield said the RTO's emergency management team meets daily, "constantly monitoring and assessing" the situation. He said the current requirements could be extended if necessary.

To protect SPP's operations and dispatch staff, all but essential traffic between the operations center and the corporate building has been prohibited, Wingfield said. The ISO has also shifted some of its operations staff to its backup operations center, 17 miles from the corporate center.

"It allows a little more distance," Wingfield said.

Whether any staff had contracted the virus, he was unable to say with any certainty, pointing to the beginning of the allergy season.

SPP said RTOs could see "new and evolving patterns of energy use" as the coronavirus continues to spread. However, it has not yet seen a "discernable difference" in load within its footprint.

"SPP continues to closely monitor the situation as it develops, and we are confident in our ability to reliably manage the operation of the bulk electric system," spokesperson Meghan Sever said in an email. ■

ISO-NE News

FERC OKs NETOs, Emera Maine Order 845 Filings

By Michael Kuser

EDF Renewables' Williston solar project in Vermont became operational in 2016. | *EDF Renewables*

FERC on Thursday accepted changes to the New England Transmission Owners' (NETOs) interconnection study deadlines and the scope of their feasibility studies (*ER19-1952*).

However, the commission only partially accepted a separate Order 845/845-A compliance filing by ISO-NE and NETOs to reflect the orders' changes to the commission's *pro forma* large generator interconnection agreement (LGIA) and large generator interconnection procedures (LGIP), ordering a further compliance filing within 120 days (*ER19-1951*).

Renewable developers EDF Renewables, E.ON Climate & Renewables N.A. and Enel Green Power N.A. had argued that the revised deadlines — extending the feasibility study from 45 to 90 days and the system impact study (SIS) from 90 to 270 days — are unreasonably ambitious. They noted ISO-NE's severe backlog, with feasibility studies averaging 229 days and SIS averaging 443 days.

But the commission said it expects "that the average study lengths will drop due to the reduced scope of the feasibility study and due to the other interconnection process improvements," citing expanded use of consultants and a streamlined approach for managing SIS models and data.

Under the previous rules, many interconnection customers that chose the separate feasibility study later modified their projects before the SIS, reducing the time savings from conducting the feasibility study first. The new rules eliminate the option to integrate the feasibility study within the SIS and allow customers to forgo the feasibility study. Feasibility studies will be reduced to a limited power flow analysis, instead of the full power flow analysis allowed previously.

Regarding the LGIP filing, the commission found that it proposed, "without justification, language that differs in one respect from the commission's requirements related to the process for analyzing surplus interconnection service requests."

The filing parties explained in their transmittal letter (but did not specify in proposed Tariff revisions) that ISO-NE would limit the analysis it performs to its existing 10-business-day material modification framework for accommodating technological changes. The commission said it "may be inadequate to complete the evaluation required under Order No. 845."

The commission required a further compliance filing to address the stand-alone network upgrades definition; interconnection customers' ability to exercise the option to build; NETOs' proposal to recover actual costs rather than a negotiated amount for oversight costs related to the option to build; the method for determining contingent facilities; requests for interconnection service below generating facility capacity; provisional interconnection service; and both the process and definition for surplus interconnection service.

FERC Partially Accepts Emera Maine Filing

FERC on Thursday also accepted amendments to Emera Maine's LGIA and LGIP but ordered a further compliance filing within 120 days (*ER19-1887*).

The commission found that the revised dispute resolution procedures in the company's LGIP comply with Orders 845/845-A and that the variations are "consistent with or superior" to them. "However, the deadlines in Emera Maine's proposed dispute resolution timeline contain an apparent incongruity," the commission said, ordering a further compliance filing to address a five-day discrepancy in stated terms.

The commission found that the LGIP's method for determining contingent facilities is in partial compliance but that proposed criteria for identifying contingent facilities "lack the requisite transparency." It ordered the company to describe the specific technical screens, analyses, triggering thresholds or criteria it will use to identify such facilities.

The commission also ordered further compliance filings to incorporate *pro forma* revisions to section 3.1 of its LGIP; to revise section 4.4.6 to clarify how it will assess changes to a generating facility's technical specifications; to clarify the deposit amount the interconnection customer is required to tender; and to specify that Emera Maine will complete its assessment and determination of whether a proposed technological change is a material modification within 30 days of an interconnection customer submitting a technological change request. ■

NEPOOL Reliability Committee Briefs

FCA 15 Fuel Security Reliability Review

New England stakeholders on March 17 pushed back on ISO-NE's draft assumptions showing that several variable changes between Forward Capacity Auctions 14 and 15 will improve system fuel security.

ISO-NE Manager of Outage Coordination Norm Sproehnle presented the New England Power Pool Reliability Committee with assumptions based on the RTO's capacity, energy, loads and transmission (CELT) forecast and consistent with Planning Procedure 10 (PP-10) Appendix I.

The assumptions show FCA 15 will see increases in gas pipeline capacity, total PV, onshore and offshore wind nameplate and demand response, coupled with lower peak load, lower winter LDC natural gas demand forecast and lower equivalent forced outage rate demand (EFORd).

The RTO also is wrapping up its Energy Security Improvements (ESI) initiative ahead of an April 15 filing deadline with FERC (EL18-182). (See NEPOOL Markets Committee Briefs: March 10-11, 2020.)

Chris Hamlen, the RTO's assistant general counsel for markets, clarified "that the fuel security retention rules are in place only through FCA 15, and so beyond FCA 15 there is no mechanism in place for performing this type of review."

Further, the RTO indicated that, in response to stakeholder concerns raised during the meeting, it would consider whether it is possible to adjust some of the assumptions in the retention analysis performed for FCA 15 to better reflect the way in which the impact analysis was performed for ESI.

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

The committee will review FCA 15 fuel security inputs and results in April and May and vote on the proposed PP10-I revisions in May, if applicable. If necessary, NEPOOL's Participants Committee will vote on the revisions in June.

The RTO also is preparing for fuel security reliability reviews of FCM retirement de-list bids, substitution auction demand bids, bilateral transactions and reconfiguration auction demand bids submitted in connection with FCA 15.

FCA-14 Auction Results

Ryan Hoskin, ISO-NE senior analyst for transmission services and resource qualification, presented results of FCA-14, which was held in the first week of February.

The RTO's 2020 capacity auction cleared at a record low of $2/kW-month, a nearly 50% drop from $3.80/kW-month in 2019. (See ISO-NE Capacity Prices Hit Record Low.)

ISO-NE filed the auction results with FERC on Feb. 18 (ER20-1025) and posted its capacity supply obligations (CSO) spreadsheet on its website. No capacity supply obligations were traded this year under the substitution auction.

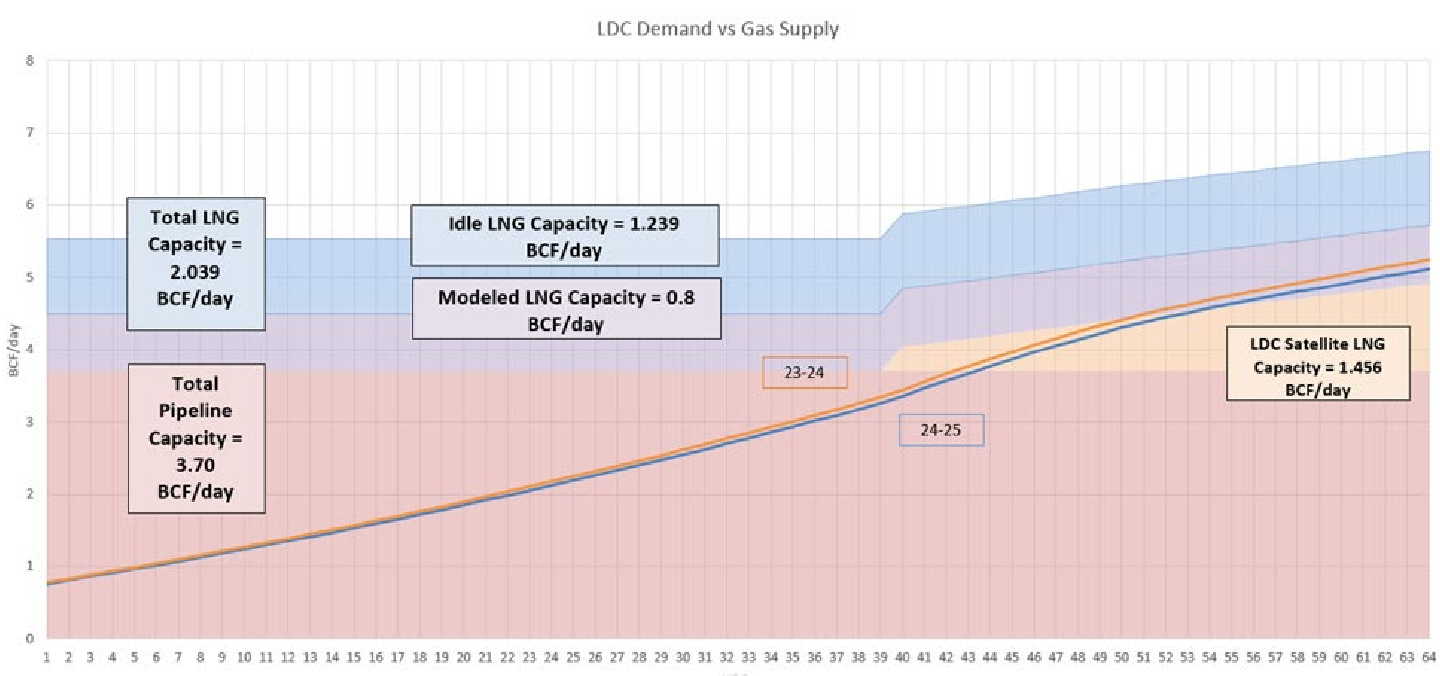
FCA 15 Capacity Zones OK'd

The RC also voted to recommend that ISO-NE identify the zonal boundaries to be used in modeling criteria for FCA 15 — unchanged from FCA 14 — in accordance with Tariff rules.

Al McBride, the RTO's director of transmission strategy and services, reviewed the proposed capacity zone construct for FCA 15, as well as the interface transfer capabilities and external interfaces.

For FCA 15, the RTO will evaluate potential export-constrained zones, including Northern New England (NNE), which includes Vermont, New Hampshire and Maine, and a portion of Maine nested within NNE.

Potential import-constrained zones to be evaluated include Southern New England (SENE),



Utilization of gas supply vs LDC demand in New England. | *ISO-NE*

ISO-NE News

which includes Northeast Massachusetts/Boston (NEMA), and Southeast Massachusetts/Rhode Island (SEMA/RI), and Connecticut.

The RTO will test the potential capacity zone boundaries and present the results at the May 2020 Power Supply Planning Committee, McBride said.

Zones that trigger the objective criteria indicating constraints will be modeled in FCA 15 and associated reconfiguration auctions, which will determine whether any of the modeled zones bind in the auction and experience price separation, he said.

Regarding internal interface transfer capability, the study noted increases associated with various transmission system upgrades, including ones in Greater Boston, Greater Hartford/Central Connecticut, Southwest Connecticut, as well as with SEMA/RI reliability project upgrades.

The study found a decrease in internal interface transfer capability associated with the updated load assumptions, updated NNE-Scobie transfer capability and the retirement of Mystic units 7, 8 and 9.

One stakeholder assumed that a drop in load would increase import capability and that the Mystic retirements will increase import capability.

"No, all these factors have the effect of lowering the transfer capability," McBride said. "The load change really becomes as much about relative load changing, [and] in particular, changes in where load is on the key transmission lines.

"If you're lowering load at a point on the transmission system that causes less local drawdown and more flow to remain on the system, but it seeks to try to get into, in this case, southeast New England, lowering load at particular points can actually cause more flow to be on those lines as it tries to serve the load beyond that point, lowering the transfer capability," McBride said.

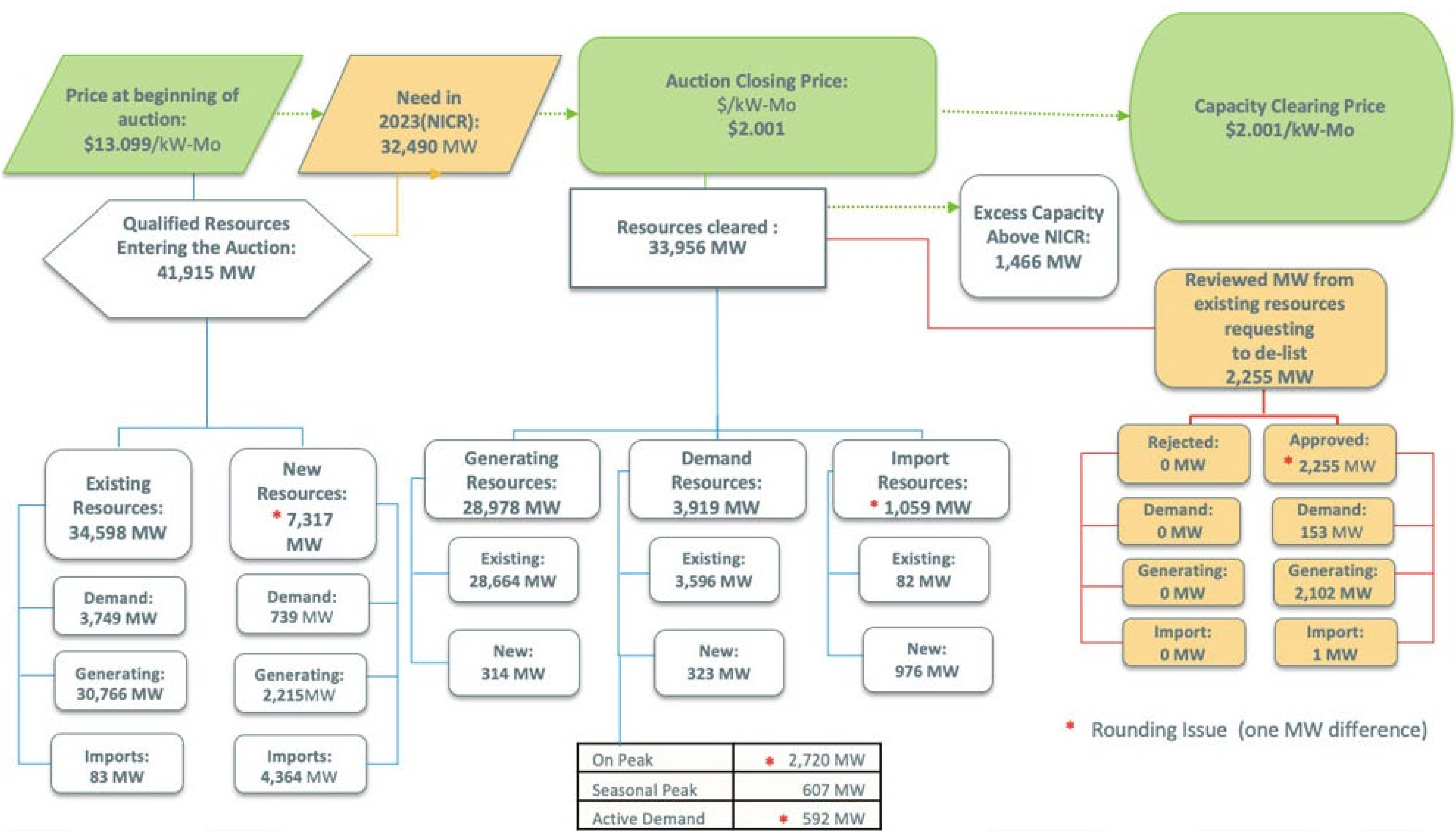
"We did some sensitivity analysis in an attempt to identify what the factors were," he said. "The predominant thing we were looking at was the change from Mystic 8 and 9 at retirement, and we wanted to make sure we understood what the other factors were."

For external interface import capability, limits are usually for the summer period, may not include possible simultaneous impacts and should not be considered as firm, McBride said.

For example, the electrical limit of the New Brunswick (NB)-New England (NE) Tie is 1,000 MW, but downstream constraints, particularly in Orrington South, led planners to adjust that tie's transfer capability to 700 MW for ability to deliver capacity to the greater New England Control Area.

Similar to what it did with NB-NE, the RTO has assumed transfer capability for capacity and reliability calculation purposes to be 1,400 MW for the 2,000 MW Hydro-Quebec Phase II interconnection, lowering the figure due to the need to protect for the loss of the line at full import level in the PJM and New York Control Areas' systems, he said. ■

— Michael Kuser

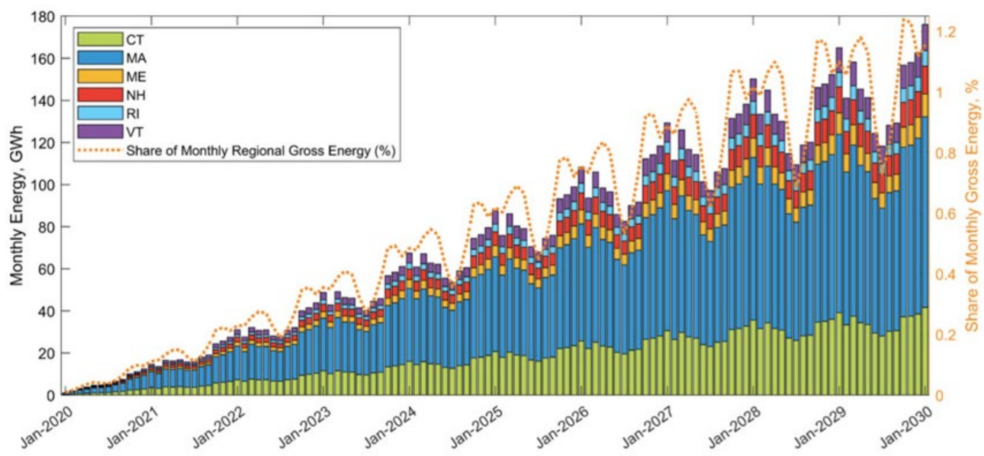


Results of New England's FCA 14. | *ISO-NE*

ISO-NE News

ISO-NE Planning Advisory Committee Briefs

Procedural Questions on Tx RFP



Final draft 2020 EV forecast in terms of monthly energy (GWh) | *ISO-NE*

Wednesday's Planning Advisory Committee meeting opened with stakeholders asking for information on proposals generated by ISO-NE's first competitive transmission solicitation in December.

The RFP seeks to address reliability concerns over the planned retirement of the Mystic Generating Station near Boston. (See *ISO-NE Issues First Competitive Tx RFP*.)

The RTO "received 36 Phase One proposals prior to the submission deadline of March 4, with costs ranging from about $49 million to $745 million," said ISO-NE Director of Transmission Planning Brent Oberlin. In-service dates ranged "roughly" from mid-2023 to 2026, he said.

"Right now, the ISO is weeding its way through all the proposals ... and we have received a number of requests to publish them," Oberlin said. "Our current policy is that we want to release that information together with the ISO's draft determination."

Oberlin noted that eight qualified transmission project sponsors submitted bids. Among them was Anbaric, which on Thursday *announced* details of its proposed 900-1,200 MW Mystic Reliability Wind Link project, including an option for an additional 1,200 MW.

In response to a question from Sebastian Libonatti, of Avangrid Networks, Oberlin said ISO-NE would not immediately release executive summaries of the various proposals. In a Thursday *memo*, the RTO explained it would wait 175 calendar days to divulge proposal details because of concerns over inadequate or inaccurate information in some of the proposals.

ISO-NE's memo said that some proposals do not meet the identified needs, or violate the Tariff, and that due to the two-phase solicitation process, some of the initial proposals' life-cycle costs are misleading.

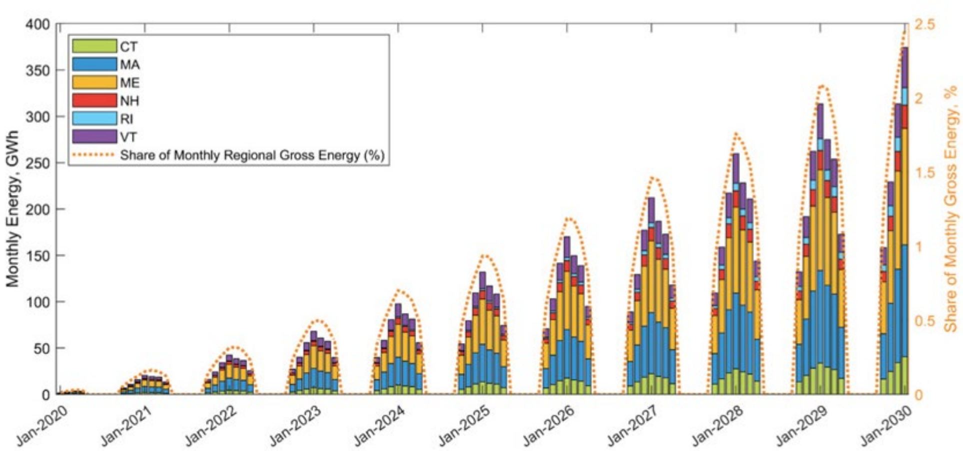
"Posting a list of the Phase One Proposals with these potential serious flaws without noting them will not facilitate meaningful stakeholder discussion or review and will result in wasted effort as non-compliant proposals are evaluated," the memo said.

During Wednesday's meeting, Phelps Turner, a senior attorney for the Conservation Law Foundation in Maine, said, "We also want to flag that we have due process concerns with the proposed schedule, which should be expedited to ensure openness and transparency, planning principles that were clearly outlined in [FERC] Order 1000, and we also want to make sure we set a good precedent with this first competitive procurement [in New England]."

Turner told *RTO Insider* that the CLF was concerned about the evaluation process for all proposals, not just for any single bid.

"Order 1000 says that stakeholders must be provided an opportunity to participate in the process in a timely and meaningful manner," Turner said, comparing the 175 days the RTO is taking to the week or so its solicitation schedule provides for stakeholders to see the proposals and submit comments.

"It's standard practice in the legal community to share redacted versions, and while we would prefer the unredacted proposals be published, redacted ones are better than nothing," he said.



Final draft 2020 heating electrification forecast in terms of monthly energy (GWh). | *ISO-NE*

Modeling More Offshore Wind, Slowly

ISO-NE presented the PAC preliminary *results* of the Anbaric 2019 Economic Study for scenarios adding from 8,000 to 12,000 MW of offshore wind in southern New England, which it found causes export interface congestion in the Southeastern Massachusetts/Rhode Island (SEMA/RI) interface.

The assumptions include retirements of nearly 4,500 MW.

The RTO's lead engineer for system planning, Haizhen Wang, led discussion of the study,

ISO-NE News

which compared the Anbaric results to those presented at last month's PAC from a similar study requested by the New England States Committee on Electricity (NESCOE). (See *ISO-NE Planning Advisory Committee Briefs: Feb. 20, 2020*.)

NESCOE, Anbaric and RENEW Northeast had requested separate analyses at the April 2019 PAC meeting.

The new analysis found that interconnecting more OSW close to load centers outside of the SEMA/RI areas (such as the Mystic and Millstone substations) would reduce the congestion hours of the SEMA/RI export interface.

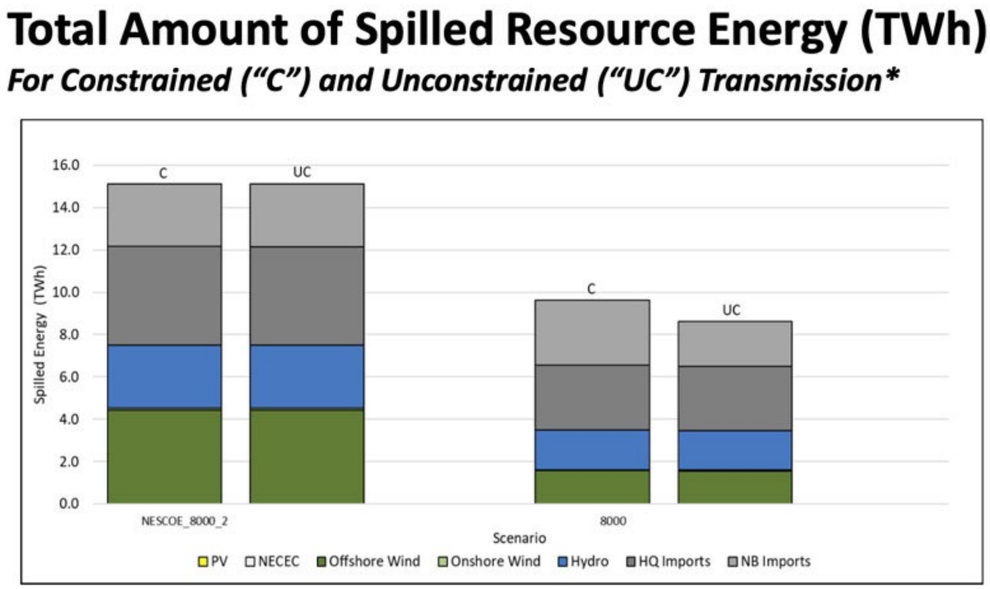
Retirement of large baseload must-run nuclear generation would lower spillage associated with over generation, the report said.

Theodore Paradise, Anbaric senior vice president for transmission strategy and counsel, asked about a rise in natural gas energy production under both constrained and unconstrained scenarios for 8,000 MW OSW, which assumes new OSW insufficient to cover the retired nuclear generation.

Peter Wong, ISO-NE manager for resource adequacy, said that more assumed nuclear retirements means fewer hours of oversupply, during which the RTO would otherwise spill the offshore wind.

"As [OSW] increases to 10,000 MW and 12,000 MW, does the natural gas run in terms of amount decrease?" Paradise asked.

"As we add more offshore wind to the system, the need for other generating resources would decrease when the offshore wind is



Total renewable spillage in the Anbaric_8000 scenario, primarily OSW and hydro, decreases approximately 50% compared to the NESCOE scenario. This is because the assumed nuclear retirements decrease the energy oversupply in the Anbaric scenario. | *ISO-NE*

not constrained by export limits," Wong said. "That's why the natural gas generation keeps decreasing as we add additional offshore wind to the system."

The RTO plans to present additional spillage and marginal emissions results from the NESCOE study in April, complete ancillary service analysis by May and publish the final report by June 1, Wang said.

The Anbaric study will see additional GridView results presented with 2015 load/PV/wind profiles in April, with the final report to be published in June or July. The RTO also will present NESCOE and Anbaric transmission cost estimates in March and April.

If time does not permit a presentation at the PAC, the RTO will still make the relevant information available to stakeholders, Wang said.

The RENEW GridView results with 2015 load/PV/wind profiles will be presented in April, and the final report in July.

Draft 2020 CELT Load Forecast

Jon Black, manager of load forecasting, presented an *update* on the annual 10-year forecasts of energy and demand that the RTO

New 2019 additions to gas generation capacity in New England | *NGA*

ISO-NE News

publishes as part of the capacity, energy, loads and transmission (CELT) report.

He focused on the heating and transportation electrification forecasts newly included in CELT 2020, saying that the usual topics of gross energy, summer demand and winter demand forecasts, as well as energy efficiency and solar forecasts will be discussed in more detail at the April PAC.

The 2020 heating electrification forecast focuses on the adoption of air-source heat pumps (ASHPs), currently the most prevalent heat pump technology, he said.

"Heating electrification is a nascent trend," Black said, noting that the emergence of other technologies, such as ground-source heat pumps, may warrant consideration in future forecasts.

One stakeholder wondered how the RTO could estimate the effect of ASHPs on load while only using three winter months of data.

"We're mapping it to heating degree days, which is a variable that we use in our forecast models," Black said. "In general, when it gets cold, you use your heat pumps more, and we are mainly focusing on getting the winter demand impact as good as we can, which is why we focused on more of the colder months.

"Essentially, those colder months yield a relationship between how cold it is and how much electricity you use before and after installing a heat pump," he said. "We apply those assumptions to all the months and days in our forecast where you have heating degree days."

A related presentation at last month's PAC showed that heat pumps and plug-in electric vehicles make up only 4% of projected 2030 annual net load, which spikes to about 10% during winter evening peaks. But the draft CELT shows EV load impact steadily rising from near zero today to 1.2% of load and nearly 180 GWh in terms of monthly energy in January 2030.

The EV forecast in the draft CELT estimates the adoption of electrified light-duty vehicles for each state and the region over the next 10 years, both battery-electric vehicles (BEV) and plug-in hybrids (PHEV), Black said.

The RTO takes the adoption estimates and extrapolates monthly demand and energy impacts per EV based on recent historical EV charging data licensed from ChargePoint. It developed energy and demand assumptions based on an aggregate EV charging profile reflecting between 118 and 247 EV drivers across the region between June 2018 and May 2019.

The aggregate profile reflects 78% residential and 22% non-residential, he said.

Natural Gas Use Rises in NE

Tom Kiley, CEO of the Northeast Gas Association, gave a brief *review* of the natural gas industry in the region, as well as of what turned out to be a mild winter. He referred to a separate winter *review* posted that day by the RTO for stakeholders seeking greater detail on the season.

"We plan for a lot of eventualities and scenarios, but certainly this COVID-19 pandemic is quite extraordinary ... and clearly emphasizes how industry coordination and communication during challenging times remain of critical importance," Kiley said.

U.S. natural gas production in 2019 set new all-time records (92.2 Bcf/d), as did consumption (85 Bcf/d).

"The EIA reported U.S. natural gas consumption grew in the electric power sector by 2.0 Bcf/d, or 7%, but remained relatively flat in the commercial, residential and industrial sectors," Kiley said.

New gas generation capacity in New England last year included PSEG Power's 485-MW Bridgeport Harbor Station 5 in Bridgeport, Conn.; NRG Energy's 333-MW Canal 3 plant in Sandwich, Mass.; and Exelon's 200-MW West Medway unit in Medway, Mass.

Two New England pipeline capacity expansion projects went into service in 2019, both part of the Portland Natural Gas Transmission System: the second phase of Portland Xpress and the first phase of Westbrook Xpress.

Projects expected to go into service this year are the second phase of Enbridge's Atlantic Bridge Project in Weymouth, Mass., the third phase of Portland Xpress, and the Station 261 Upgrade on the Tennessee Pipeline in Agawam, Mass.

Since 2012, more than a million new households have been connected for natural gas use in the six New England states plus New Jersey, New York and Pennsylvania, he said.

"Today this represents over 12 million households in total," Kiley said. ■

— Michael Kuser

MISO News

Virus Fear Sends MISO Board Week to the Web

By Amanda Durish Cook

MISO said March 16 that it will hold its quarterly Board Week via conference call only, canceling the New Orleans event as the COVID-19 coronavirus extends its reach.

The cancellation was announced in a joint *letter* from CEO John Bear and Board of Directors Chair Phyllis Currie. The two said the six committee meetings and full board meeting scheduled for March 24-26 will continue as *planned*, but in WebEx/dial-in format.

"At this point, the board and MISO senior management have concluded that it is prudent for us to take more aggressive steps to keep our employees and stakeholders safe and do our part to limit the spread of this virus," Bear and Currie wrote. "We did not take this decision lightly. MISO's Board of Directors views these meetings as extremely important aspects of the stakeholder process that provide valuable opportunities for engagement with our stakeholders. As we have monitored the situation overall, paying special attention to member and state travel policies, we have concluded that this is the right decision for the region."

MISO's March 2019 Board of Directors meeting in New Orleans | © *RTO Insider*

MISO also announced that all other stakeholder meetings will continue to take place via conference call through May 1. The RTO's conference call-only policy originally applied to meetings held March 9-13. (See *MISO Steps Up COVID-19 Response*.)

MISO has hosted its spring quarterly Board Week in New Orleans uninterrupted since 2011, two years before Entergy joined the RTO and made the city part of the footprint.

The cancellation occurred less than one week before stakeholders and MISO staff were set to converge on the Westin Hotel in downtown New Orleans. The RTO apologized for the short notice, explaining that it tried to collect "as much input and direction as possible" before its decision.

Advisory Committee Chair Audrey Penner said she fully supported MISO's decision "to protect its staff and stakeholders while the uncertainty over the COVID-19 situation continues to play out." She pointed out that the committee has held meetings via conference call in the past.

"While they are a little trickier to manage, I don't anticipate any issues next week that would prevent us from having a good discussion. Having said that, holding 'policy-type' discussions via conference call [isn't] ideal, so we are limiting those types of discussions next week," Penner said in an email to *RTO Insider*.

Penner said she will prepare a verbal report to the board as usual, this time covering the AC's recent recommendation that the RTO create a new "affiliate" sector for hard-to-define members. (See *MISO Advisory Committee OKs 11th Sector*.)

Steering Committee Chair Tia Elliott canceled the March 25 meeting of her committee and said it will next meet in an April conference call.

Elliott, who also serves as vice chair of the Advisory Committee, said she had full confidence in MISO and Penner to navigate the AC meeting by conference call.

"No doubt it can be tricky at times, but there is a chance we have a glitch during an in-person meeting too," Elliott said. "I would encourage stakeholders to be patient, kind, and show grace during these conference calls, and to each other, especially during this unprecedented time we are all living through together."

The AC has more than 50 *members* and alternates; audiences regularly exceed 100 people at Board Week.

MISO promised more updates on COVID-19's effect on its stakeholder process and echoed Elliott's message of unity.

"In times such as these, it is essential that we all work together to deliver electricity reliability to serve our customers," Bear and Currie said. ■

MISO News

BlueIndy Pulls Plug on EV Rideshare Service

By Amanda Durish Cook

Marketed as an eco-friendly alternative to car ownership, Indianapolis' BlueIndy electric vehicle rideshare service will cut the engine and go out of business this spring.

After four years of providing shared EVs, French owner Bolloré Logistics will end BlueIndy's operations May 21, leaving city leadership to decide whether to purchase the company's assets.

BlueIndy said it "did not reach the level of activity required to be economically viable," reporting that it attracted about 11,000 members who took about 180,000 rides over the ride-sharing service's existence.

Complicating matters, BlueIndy indefinitely suspended the service beginning this week in response to the spreading COVID-19 pandemic in Indianapolis.

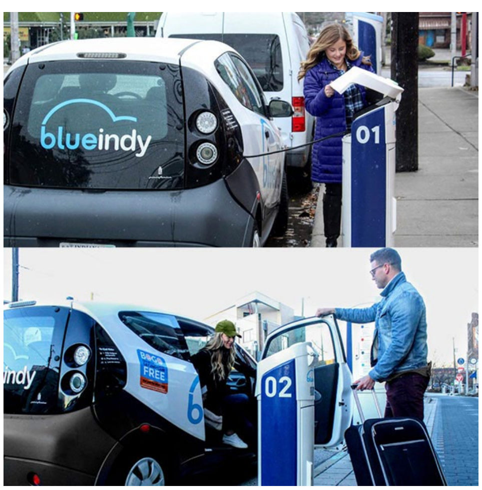
"We thank you for your understanding and hope to be able to restore service as soon as the situation permits. Let us remain united and responsible," BlueIndy's homepage read.

It remains to be seen whether customers will ever again have the chance to drive a BlueIndy car.

Wrong Market?

BlueIndy had bestowed the Indiana capitol with the distinction of the largest network of public charging stations of any U.S. city. However, critics from the start said the service only makes sense in a higher-density city with a smaller geography — not Indianapolis' nearly 880,000 inhabitants spread over 372 square miles. Bolloré Logistics spun off a Los Angeles version of the service — *BlueLA* — in partnership with the Los Angeles Department of Transportation. The sister rideshare remains open though operations there are also suspended due to COVID-19.

One of 90 BlueIndy charging stations across Indianapolis | © *RTO Insider*



BlueIndy promotional photos | *BlueIndy*

"Indianapolis drivers have been slow to adopt alternative transportation options and car ownership remains extremely high," BlueIndy explained in a late 2019 press release.

Now Indianapolis is weighing whether it should purchase the approximately 90 EV charging stations scattered on public rights-of-way throughout the city. BlueIndy originally anticipated owning as many as 500 cars and up to 200 stations in the city.

"Leading up to [May 21], we will be having conversations with neighbors, corporate partners and personal mobility advocates to explore whether financially sustainable options exist that would allow us to put the existing infrastructure to use — either with another ride sharing program or as charging stations for electric vehicles," City of Indianapolis Deputy Chief of Staff Taylor Schaffer said in an email to *RTO Insider*.

Schaffer said Indianapolis' 15-year contract with Bolloré Logistics stipulates the city can notify the company it would like to purchase the infrastructure at any point within 90 days of the contract's end.

"This means the city has until mid-August to decide whether to purchase the infrastructure or not," Schaffer said.

Schaffer did not comment on a possible purchase price for the assets, though the city has previously said it has the option to appraise and negotiate a fair market value.

BlueIndy got off to a rocky start in 2016 when the Indianapolis City-County Council contended that Bolloré Logistics' process for placing stations lacked transparency. (See *BlueIndy EV Sharing Program Seeks Rebound.*) As a result of negotiations, BlueIndy paid the city an annual $45,000 franchise fee meant to cover the loss of parking meter payments due to the curbside stations.

The project was slated to cost a total of $50 million, with the company investing $41 million, the city contributing $6 million and Indianapolis Power & Light Co. ratepayers covering the remaining $3 million.

In 2017, BlueIndy *showed* a $22.5-million deficit. The company has not released recent financial standings.

Indianapolis' former Republican Mayor Greg Ballard called the service a "clean, affordable transit option to help connect visitors and residents with all that Indy has to offer" when the collaboration was announced in 2015.

It's unclear how much BlueIndy was affected by IndyGo's new rapid transit electric *bus line*, which opened its first route last year along many of BlueIndy's curbside electric charging stations.

Multiple requests to interview remaining BlueIndy employees went unanswered. BlueIndy Managing Director James Delgado appeared to stop *tweeting* about the service in early 2019.

"We believe that the continued reliance and predominant use of traditional personal vehicles is not sustainable long term in a growing urban environment and the need for additional mobility options to complement operators in Indianapolis including BlueIndy, IndyGo and the Pacers Bikeshare is significant," BlueIndy said last year. ■

MISO News

Memphis Muni Mulls Move to MISO

By Amanda Durish Cook

Memphis Light, Gas and Water is mulling whether to defect from the Tennessee Valley Authority to acquire power from MISO or another wholesale supplier.

A decision could come as early as this spring.

MLGW spokesperson Angelika Taylor confirmed that the utility is weighing an exit from TVA for another supplier for economic reasons.

"We are doing an integrated resource plan to determine the optimal electricity-producing resource mix to provide MLGW customers and our community with reliable, low-cost power as we consider whether or not to discontinue being a wholesale customer of TVA," Taylor said in an email to *RTO Insider*.

The municipal utility's *IRP* is scheduled to be completed by May, though Taylor warned that the spread of COVID-19 could delay that schedule. The city's elected officials are expected to decide on the plan sometime this year.

Their decision could allow MISO to add another state to its 13-state footprint. As a rule, MISO does not reveal the names of utilities and companies that approach it for membership until its board of directors vote on approval during one of its public meetings.

| *TVA*

MLGW's move makes sense to environmental nonprofit Friends of the Earth (FOE), which for two years has urged the utility to pursue an alternative to TVA.

FOE commissioned The Brattle Group to prepare an *analysis*, released in September, that finds MLGW could save anywhere from $240 to $333 million per year by 2024 if it accesses lower-cost power across the Mississippi River and builds at least 350 MW or more of its own renewable generation.

"Certainly in our analysis, and the work that The Brattle Group has done for us, MISO is right at the top" as an alternative supplier option, said FOE attorney Herman Morris, Jr., also a former MLGW CEO.

MLGW has a few options as it crafts its IRP: Attempt to join MISO or another wholesale power supplier, produce its own power or undertake a combination of the two. The utility doesn't currently generate any of its own power.

Another less probable option would involve sales from the embattled and unfinished Bellefonte Nuclear Power Plant in Alabama. Former Chattanooga developer Franklin L. Haney is trying to finalize the *purchase* of the plant from TVA, which contends he lacks the proper permitting. The dispute will likely head to trial this year.

'Really Significant' Savings

"From at least the Friends of the Earth perspective, all alternatives are preferable for the potential for new green and renewable sources as well as reliability and lower cost," Morris told *RTO Insider*. "It's certainly my personal view that MISO is a more than viable option … They serve a lot of capacity, and they're reliable, greener and a whole lot cheaper than TVA. My sense is we'll probably see some combination of self-generation and purchases of power from across the river, somewhere, somehow."

Morris said TVA's wholesale power costs about 7.5-8 cents/kWh versus the 4-4.5 cents/kWh that MISO offers.

"It's simply hard to overcome the math in these things. That's not just significant, that's really significant. You can go a long way with savings of $300 million a year," Morris said.

Some of MLGW's savings from switching suppliers could be spent on the construction of its own renewable generation and to defray

MISO News

the cost of connection to the MISO system, Morris said.

"Interest rates are so low, especially now. It just can be done," he said.

"As large as [MISO] is, there's a river between us. There's not a great understanding by people on our side of the river of who MISO is," Morris said. "[FOE] is not trying to promote MISO so much as we're trying to educate the community as to what its options are. What we want to see is a fact-driven discussion: Is it possible to get a wholesale supplier less expensive than TVA? Is it possible to create a greener portfolio? We want to put these in front of community leaders and have them make a decision."

TVA's current generation *portfolio* consists of 37% nuclear, 24% coal, 20% natural gas, 9% hydro, 7% energy efficiency and 3% wind and solar generation, with a total capacity of about 35 GW. Peak load can reach 32 GW, and MLGW accounts for about 10% of TVA load. TVA sometimes purchases power from MISO.

"When you've got a fleet of old coal plants, many of which are supplied by Kentucky and West Virginia coal fields in the valley, and you've got 50-plus-year-old nuclear generation, you can't turn that on a dime. You can't say, 'we're going to be this next year,'" Morris said.

Majority in Favor

Last year, TVA's board of directors approved an *integrated resource plan* that adds 14 GW of new solar generation, 5.3 GW of energy storage and up to 2.2 GW of energy efficiency savings by 2038. The plan also includes between 2 and 17 GW of new natural gas generation. TVA also has plans to retire its Paradise and Bull Run coal plants in 2020 and 2023, respectively.

Morris points out that about a third of Memphis residents live at or below the poverty line. "It's important for people at the bottom economic rung that we are prudent and judicious in selecting our supplier. We believe that by having a more economical source of wholesale power, we can save this community close to a million dollars a day."

He said there's popular support in Memphis for getting cheaper and cleaner energy, especially considering that TVA generation and transmission costs comprise about 80% of customers' residential electric bills.

"Right now, if you're in the TVA valley, TVA sells you 100% of your power. And that's it. It's an all-requirements contract. And that's probably made them a little less energetic — no pun intended — and more willing to ride these coal and nuclear plants to the bitter end," Morris said. He also questioned the societal cost of TVA's coal ash and spent nuclear rods.

The reduction in load from a MLGW exit could make it easier for TVA to consider speeding up retirement of some of its aging, inefficient plants, Morris added.

He estimates it would take at least five years for MLGW to make the transition from a non-generator to a modest generator for some of its load. He also noted that an exit from TVA would involve negotiations.

"There might be some legal issues to parse through, but we think the philosophy of the industry — and FERC — is strongly supportive of communities getting the best-cost supplier they can find."

FOE this month conducted a *poll* that found 57% of Memphis residents would like to see MLGW leave TVA, with 20% opposed to such a move.

"The most important thing for this community is to identify a cheaper, more economical and greener source of wholesale power, and MISO is all of those things," Morris said. "There is a robust voice from environmentally-conscious citizens in our community. I think whatever the outcome is, it will have to involve some element of renewable, clean, green supply." ■

MISO News

FERC Shelves Grievances over MISO Capacity Auction

By Amanda Durish Cook

FERC on Thursday denied what might be a final bid to recalibrate the results of MISO's 2015/16 capacity auction, blocking Public Citizen's request for rehearing over the highest capacity prices ever seen in the footprint.

MISO's 2015/16 Planning Resource Auction has lived on in legal proceedings for more than five years. FERC last year wrapped up a three-year investigation into the PRA when it ruled the RTO's Zone 4 $150/MW-day clearing price just and reasonable, declining to set up an evidentiary hearing. It also found that Dynegy had not manipulated the market to produce the high prices in southern Illinois. (See *FERC Clears MISO 2015/16 Auction Results*.)

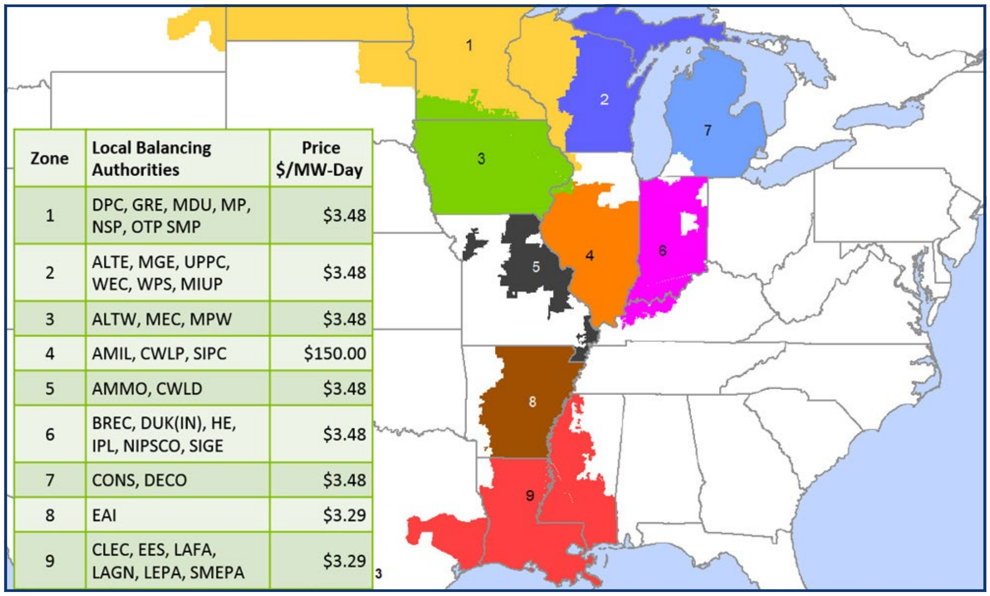
The commission said a clearing price isn't unjust simply because it's higher than expected. However, the decision remains unsubstantiated because FERC didn't make any evidence from the investigation public when it abruptly ended the probe.

Soon after the ruling, Public Citizen claimed FERC wrongfully dismissed complaints alleging Dynegy manipulated pricing in the auction, violating the *Administrative Procedure Act* for not providing explanation or summarizing evidence and abandoning its just and reasonable ratemaking responsibility under the Federal Power Act. (See *Public Citizen Contests FERC Ruling on MISO Auction*.)

The commission rebuffed those arguments in its March 19 order (*EL15- 70*), leading Commissioner Richard Glick to once again issue a dissent and separate statement over the transparency of FERC's investigation.

FERC's other two commissioners, Chairman Neil Chatterjee and Bernard McNamee, said they remained unpersuaded that results were underhanded because Dynegy's bids were permitted under a "valid, market-based rate tariff" and the bids met criteria under the FERC-approved MISO Tariff at the time. They also said they have discretion in market manipulation investigations, though they again declined to reveal any specifics of the investigation into Dynegy and Zone 4 prices.

The commissioners said they were able to monitor Dynegy's market-based rate through accurate quarterly reports, triennial market power updates and change-in-status updates. They also said they oversaw the market monitoring and mitigation rules in MISO's Tariff.



Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$3.48
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$3.48
3	ALTW, MEC, MPW	$3.48
4	AMIL, CWLP, SIPC	$150.00
5	AMMO, CWLD	$3.48
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE	$3.48
7	CONS, DECO	$3.48
8	EAI	$3.29
9	CLEC, EES, LAFA, LAGN, LEPA, SMEPA	$3.29

2015/16 MISO PRA results | *MISO*

Public Citizen had argued that just eight months after the auction, FERC found MISO's 2015 market power provisions no longer just and reasonable and ordered MISO to reset its $155.79/MW-day maximum bid to about $25, while also directing the RTO to better gauge power exports. (See *FERC Orders MISO to Change Auction Rules*.) But the commission said those new policies were to be viewed on a going-forward basis.

Glick Hints at Unfinished Investigation

However, Glick said the order was another "sidestep" of the crux of the proceedings, failing to answer the question of whether the resulting prices were reasonable considering the allegations of market manipulation on Dynegy's part.

"Rather than directly confronting that issue, the commission states that the relevant Tariff language was followed and that a non-public investigation was conducted and did not, in my colleagues' view, uncover manipulative conduct. That enforcement proceeding, however, was terminated by the chairman without a vote by the commission and the details of that investigation remain confidential," Glick wrote. "Accordingly, the commission has at no point provided Public Citizen with an adequate response to the concerns raised in its complaint or explained why, in light of those concerns, the auction results were just and reasonable."

Glick added that following relevant tariffs does not create a "safe harbor" for market manipulation.

"I am not aware of any authority to support the proposition that a market participant can commit market manipulation with impunity so long as it does not violate the relevant tariff language," Glick said. He also said that courts' interpretations of the Securities Act of 1934 "have repeatedly recognized that a facially legal action can constitute manipulation when it is taken for an improper purpose."

Glick also reiterated his displeasure that he was not consulted before Chairman Chatterjee closed the nonpublic investigation. He also hinted that there might have been evidence that Dynegy had committed wrongdoing.

"Had I been consulted, I would have argued against terminating the enforcement process. Because the details of the investigation remain non-public, I cannot explain why I believe that the chairman erred in terminating the enforcement process. Suffice it to say that I am confident that the evidence uncovered in that investigation was more-than-sufficient to press ahead," he wrote.

Glick ended by echoing complaints that the commission's decision "does not provide even the scantest reasoning to support its finding that the nearly 1,000% year-over-year increase in the MISO Zone 4 capacity price had nothing to do with market manipulation.

"Instead, all we have is the Commission's unsubstantiated assurance that there is nothing to see here." ■

MISO News

Rehearing Denied over MISO RA Construct

By Amanda Durish Cook

FERC last week affirmed its 2018 ruling approving MISO's current resource adequacy construct, rejecting multiple rehearing requests from critics of the decision.

Among those requesting rehearing were a collection of Midwest transmission-dependent utilities, a group of major capacity suppliers, Main Line Generation and MISO's Independent Market Monitor.

The commission said most of those arguing for rehearing sought to make MISO's RA construct more like the centralized capacity markets of Eastern RTOs/ISOs. But FERC noted that those designs ignore the fact that the RTO must defer to multiple state jurisdictions in its 13-state reach and that its RA design is meant to be complementary to states' authority (*ER18-462*).

The commission also pointed out that 90% of MISO's load is served by vertically integrated load-serving entities that for the most part don't use the RTO's capacity auction to meet capacity requirements.

"... [U]nlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's auction is not — *and has never been* — the primary mechanism for its LSEs to procure capacity," the commission stressed.

Two years ago, MISO pre-emptively refiled its entire RA construct in response to a D.C. Circuit Court of Appeals ruling that FERC overstepped its "passive and reactive" role when it prescribed revisions to PJM's minimum offer price rule. MISO was concerned the decision could impact some of the RA rules that had been guided by FERC's recommendations.

In a pair of orders a few months later, FERC both vacated and reinstated MISO's entire RA construct, ultimately leaving the RTO's current capacity auction format — and past auction results — undisturbed. (See *FERC Vacates, Upholds MISO Resource Adequacy Rules*.)

Still No Sloped Demand Curve, MOPR, Forward Mechanism

MISO Independent Market Monitor David Patton used the RA refiling as an opportunity to ask FERC to order the RTO to employ a sloped demand curve in its capacity auction in order to produce more efficient pricing. (See *MISO Monitor to FERC: Order Sloped Demand Curve*.)

MISO Little Rock headquarters | *MISO*

On rehearing, Patton again argued that a good RA design "will produce price signals sufficient to attract and retain the necessary amount of capacity" and that FERC itself made that issue paramount when accepting the sloped demand curves used in NYISO, PJM and ISO-NE's capacity auctions.

But in last week's ruling, FERC said MISO's high percentage of vertically integrated utilities sets it apart it from NYISO, PJM and ISO-NE because MISO's RA is not determined by its capacity auction prices alone. It said the RTO's vertical demand curve is fine for now.

"... [W]e continue to find that MISO's resource adequacy construct enables the MISO region to maintain sufficient resources to meet system-wide and locational reserve requirements," the commission said, noting that last year's Organization of MISO States-MISO RA survey indicates sufficient capacity supply through 2022.

The commission also rejected the capacity suppliers' request that the RTO conduct the auction on a three-year forward basis for retail-choice areas in Illinois and Michigan. FERC found that both a prompt auction and a multi-year forward capacity auction can be reasonable, and the suppliers' support of one design over the other wasn't a justification to order MISO to change its auction timing. The commission also told the suppliers that MISO's auction didn't require a minimum offer price rule, again noting that vertically integrated utilities own about 90% of capacity in MISO.

The commission also rejected the suppliers' argument that it's discriminatory for the MISO capacity auction to be voluntary for buyers and mandatory for sellers who have uncommitted capacity. FERC said while it does have an obligation to ensure that "similarly situated market participants are not unduly discriminated against ... it does not follow that market participants who are not similarly situated are unduly discriminated against simply because they are subject to different sets of rules."

The transmission-dependent utilities argued that the RA construct should allow new capacity resources to obtain long-term financial hedges to shield against inter-zonal price separation in the auctions. FERC said such a provision fails to consider the capacity auction's main purpose of ensuring reliability during peak days.

The commission said MISO's local clearing requirements and capacity import and export limits are essential to zonal reliability and declined to order alterations so more resources could compete inter-zonally. The commission also left in place MISO's zonal delivery charge, which the RTO uses to cover congestion between zones when an LSE that submits its own fixed resource adequacy plan taps resources in a lower-priced local resource zone to serve demand in a higher-priced zone. The commission disagreed that the zonal delivery charge is a form of rate pancaking, pointing out that the charge is meant to cover auction price separation between the LSE's location and its load, not transmission service. Capacity prices should reflect the "locational cost of capacity," FERC said.

MISO's RA construct "appropriately balances the competing goals of maximizing competition and ensuring reliability by allowing LSEs to serve their load with remote resources but having them bear the risk of auction price separation if there are impediments to the deliverability of such resources," FERC said. ■

MISO TO Cost Recovery Provision Approved

By Amanda Durish Cook

FERC on Thursday approved a new MISO Tariff provision that allows transmission owners to recover interconnection facility operations and maintenance costs from interconnection customers.

The decision allows MISO to include a new rate schedule — Schedule 50 — to allow TOs to recoup costs from interconnection customers for "reasonable expenses, including overheads, associated with operation and maintenance, and repair" of TO-owned interconnection facilities (*ER20-170*).

MISO TOs filed in October for the new rate schedule.

"While relevant provisions of a MISO generator interconnection agreement … already explicitly provide that interconnection customers 'shall be responsible' for all reasonable [operations and maintenance] expenses, there is presently no mechanism in the Tariff to enable the calculation and recovery of such expenses from interconnection customers," the TOs explained to FERC.

| *MISO*

MISO joined the filing as administrator of its Tariff but took no stance on the proposed revisions.

The TOs plan to allocate O&M annual charges based on a calculation involving the interconnection facilities' installed costs as a share of a total annual transmission gross plant. When installed costs aren't available for calculation, TOs will have to submit filings so FERC can review the alternate calculations.

In accepting the new schedule, FERC disagreed with renewable energy proponents that the Schedule 50 approach would "unduly" shift costs to interconnection customers. Some had argued that a process including transmission facilities didn't translate well for interconnection facilities because they're newer and less prone to maintenance charges. But the commission said the average useful life or O&M costs of an interconnection facility aren't much different than the average useful life or O&M costs "of other similar transmission facilities."

Other clean energy advocates said O&M costs should be assigned directly to interconnection customers instead of using a calculation. FERC again disagreed.

" … [E]ven in the instances where transmission owners utilize direct billing, not all costs are able to be directly assigned, some are assigned based on various allocators, and some costs are not even recovered," the commission explained. ■

Another Rejection for MISO Cost Allocation Plan

By Amanda Durish Cook

| MISO

MISO's effort to implement a new cost allocation method for large economic transmission projects was dealt a major blow last week when FERC rejected the plan for a second time (*ER20-857*).

The commission's March 20 order raised the same cost-causation issues that dogged the RTO's first cost allocation filing, rejected last June. (See *MISO Allocation Plan Fails on Local Project Treatment*.)

At the heart of the issue was the same new local economic project category, meant for smaller, economically driven transmission projects between 100 kV and 230 kV, where 100% of costs would be allocated to the local transmission pricing zone containing the line.

MISO altered its original filing so that local economic projects had to pass only a local benefits test, no longer requiring them to demonstrate a regional 1.25:1 benefit-to-cost ratio while only allocating their costs to the local transmission pricing zone where they are located.

But FERC pointed out that MISO's latest proposal would have still effectively measured the value of a local economic project on a regional basis through use of three benefit metrics used on regionally allocated projects — with the project costs shared at only the local level.

"[T]he proposed cost allocation method inappropriately relies on a benefits metric, the MISO-SPP Settlement Agreement metric, that determines benefits outside of the local transmission pricing zone where the local economic project is located, but then disregards these benefits by allocating costs for the project solely within that transmission pricing zone," FERC said. " … [T]he proposed local economic project local benefits analysis will likely require MISO to disregard regional transmission benefits that it will necessarily uncover when applying the MISO-SPP Settlement Agreement costs benefit metric."

MISO's proposal would have lowered the voltage threshold for its market efficiency projects from 345 kV to 230 kV, eliminated the current 20% postage stamp allocation and added new benefit metrics for savings from the avoided costs for reliability projects and cost reductions related to the MISO-SPP transmission contract path. The proposal also would have provided limited exceptions to the competitive bidding process if a transmission project were needed immediately for the sake of reliability. As it did with the first rejection, FERC again said it had no problems with the other aspects of the plan.

Some stakeholders had previously argued that MISO's revised proposal still wrongly presumed that all sub-230 kV projects cannot deliver regional benefits. They said the projects shouldn't be excluded from a regional allocation when appropriate. (See *MISO Makes U-turn on Cost Allocation Policy*.)

FERC seemed to agree, saying MISO's proposal to use the adjusted production cost savings metric would have required RTO staff to be willfully blind to some benefits of the smaller projects for purposes of cost allocation.

"It is incongruous to state that a metric is the most reliable measure of benefits, and then to ignore that measure for purposes of cost allocation for local economic projects," the commission said.

Interregional Filing Also Rejected

In a separate order, FERC similarly ruled out MISO's companion filing to update its cost allocation for interregional projects with PJM over the same deviation from the cost-causation principle. (*ER20-862*).

The commission ordered MISO to instead use a design based on adjusted production costs for economic interregional projects 100 kV and above with PJM, exercising its authority to ensure just and reasonable rates.

FERC said MISO should use its existing adjusted production cost savings metric to allocate its share of the cost of MISO-PJM interregional economic transmission projects.

Using MISO's own words, FERC said the adjusted production cost savings metric "has been regarded as one of the most reliable measures of the net economic impact of a planning decision on energy cost in MISO."

A new cost allocation for MISO's share of interregional projects with PJM was necessary under a six-year-old FERC compliance directive requiring MISO to lower its interregional market efficiency project voltage threshold to 100 kV. MISO and PJM were ordered by FERC in 2013 to lower thresholds after the Northern Indiana Public Service Company complained about shortfalls in the RTOs' interregional planning process.

"While we recognize the complexity of the issues underlying MISO's proposal, we also recognize the need for MISO to come into compliance with the NIPSCO compliance order's directive in a timely manner," FERC said.

The commission said it rejected the filing without prejudice because the interregional allocation proposal referred to and relied on provisions in MISO's regional cost allocation filing. The RTO also filed in January to create a cost allocation for its share of some interregional projects with PJM and had also proposed that its share of interregional economic projects with voltages below 230 kV — but at or above 100 kV — be allocated 100% to the transmission pricing zones where the project is located. ■

NYISO News

FERC Denies Brooklyn Battery Waiver

By Michael Kuser

FERC on Thursday denied NYC Energy's (NYCE) request for a limited waiver of *NYISO* interconnection rules for its 80-MW energy storage facility proposed to be situated on a barge moored at the Brooklyn Navy Yard.

NYCE sought waiver of a Tariff provision that requires a project to withdraw from the ISO's interconnection queue if it fails to comply with certain interconnection procedure requirements (*ER20-629*).

NYCE explained that its project is a modification of a previously permitted combined cycle gas/oil-fired generating facility and that the ISO also completed a materiality review of the project regarding a change in technology in August 2019. Further, the developer said it notified NYISO of its intention to enter the 2019 class year of the interconnection queue, and the ISO acknowledged the request on Aug. 16, 2019.

In addition, NYCE said it delivered an executed facilities study agreement (FSA) to NYISO on Sept. 11, 2019, along with all other required materials, including a $100,000 FSA study deposit.

But the company noted that when it submitted the FSA, it learned that NYISO had concluded that a previous finding of no adverse environmental impacts under state law applied only to the original project, not to the newer battery project, meaning the latter did not satisfy regulatory milestones required for the queue.

NYCE withdrew its effort to join the 2019 class year but sought a Tariff waiver in order to hold a position in the queue. NYISO supported NYCE's waiver request, saying that absent a waiver from the commission, the ISO could not accept the two-part deposit for NYCE's project after Sept. 16, 2019.

The ISO further said it did not dispute NYCE's assertion that no adverse harm will result to other projects if the waiver request is granted because NYCE's project no longer sought to participate in the 2019 class year.

The commission rejected NYCE's arguments, saying "the record reveals no reason why NYCE could not have satisfied the regulatory milestone in accordance" with NYISO's Tariff provisions, and the company "has not adequately explained why it assumed that prior regulatory reviews for a different generating facility would satisfy the regulatory milestone in the [Tariff]."

"Specifically, although we find no evidence of ill intent by NYCE, we find that NYCE has not demonstrated that it acted in good faith," said the order confirmed by Chairman Neil Chatterjee and Commissioner Bernard L. McNamee.

The commission also found that NYCE failed to demonstrate that its waiver request was limited in scope.

It said "a waiver is not limited in scope if the party requesting waiver does not provide a compelling reason why it should be afforded special treatment compared to others. Here, NYCE seeks to shield itself from the consequences of its choices."

Commissioner Richard Glick dissented in a separate statement.

"First, I see nothing in the record — or today's order — indicating that NYCE did not act in good faith," Glick said. "After all, it does not strike me as totally unreasonable to assume that, if an oil/natural-gas fired unit can pass environmental muster, then a non-emitting battery storage facility is likely to clear that bar as well."

Glick argued that the waiver request is limited in scope insofar as it applies only to this facility and only to this single failure to comply with the applicable deadlines, and that the request remedies a concrete problem.

"Finally, I agree with NYISO that granting the waiver would not have undesirable consequences, such as harming third parties," Glick said. "I also understand why NYCE sought to rely on its previous environmental determinations rather than fork over an additional quarter-million dollars in collateral ... [which] does not, in my view, indicate that it acted in bad faith." ■

Manhattan as seen from the Brooklyn Navy Yard.

NYISO News

NYISO Business Issues Committee Briefs

Storage Tariff Changes Approved

NYISO's Member Relations team: (from left) Selina Dean, Leigh Bullock, Kirk Dixon, team manager Mark Seibert, Debbie Eckels and Jennifer Davies. | *NYISO*

The Business Issues Committee on Wednesday approved additional Tariff language for the energy storage resource (ESR) participation model to address issues identified during software development for the ESR project.

The language spells out details regarding day-ahead margin assurance payments (DAMAP); the method for setting feasible day-ahead and real-time schedules; generator offer caps, mitigation and reference levels; and installed capacity (ICAP) supplier bidding requirements.

The revisions to *MST Section 25 Attachment J* clarify which of the two energy contribution formulas will apply to ESR schedule changes.

A portion of the attachment that applies to fast-start units also will be revised to specify that those units that increase their minimum generation bids in real-time will not be eligible for DAMAP, consistent with Tariff rules that apply to increasing incremental energy bids or start-up bids in real-time.

The ISO also is revising MST 4.4.2.1 to support the market software used to ensure feasible real-time schedules for ESRs.

The ISO's real-time dispatch software will account for the energy level of all ESRs to prevent infeasible dispatch of both self-managed and ISO-managed resources. The ISO's original Order 841 compliance filing stated that the software will reduce the ESR's upper operating limit (UOL) or increase its lower operating limit (LOL) as needed to produce a feasible schedule. But during the software development, the ISO realized such adjustments are unnecessary and may be inefficient. (*See FERC Partially Accepts NYISO Storage Compliance*.)

Under the change, the software will determine feasible real-time schedules based on an ESR's actual telemetered energy storage level.

The offer price capping logic in MST 23.7.2 will be revised so that offers to withdraw energy are capped at the lowest of the energy offer, the price allowed by the current capping logic or the price needed to account for the unit's round-trip efficiency. The ISO said the change will prevent performance issues with security-constrained unit commitment (SCUC), real-time commitment (RTC) and real-time dispatch (RTD).

The current price capping logic will continue to be applied if a unit's energy offer does not cross zero and will be applied to all energy segments that are greater than zero.

Revisions to MST 23.4.2.2 will allow adjustments to the mitigation of an ESR's incremental energy curve if needed to account for the ESR's round-trip efficiency.

Revisions to Section 23.1.4.3 will exempt ESRs from requiring a new unit reference level, specifying that they should be calculated using cost-based reference levels. "New unit reference levels are based on historical LBMPs and would not be representative of ESRs' costs or operating parameters such as round-trip efficiency," the ISO said in a *presentation*.

The ISO had proposed that ESR ICAP suppliers have a day-ahead market (DAM) bid/schedule/notify (B/S/N) obligation equal to the ICAP equivalent of unforced capacity (UCAP) sold, like other ICAP suppliers.

After making its Order 841 compliance filings in December 2018 and May 2019, the ISO realized that when an ESR uses the ISO-managed energy level bidding parameter and enters the DAM with an energy level insufficient to satisfy its obligation, the ESR could submit bids to inject energy that appear to satisfy the B/S/N commitment, but that would not provide the ISO with all the promised energy.

NYISO is proposing that all ESR ICAP suppliers must B/S/N the full range of the ESR, including both the ISO- and self-managed energy level bidding parameters.

The ISO said the language is needed to "harmonize" the physical and operating characteristics of ESRs with the purpose of the existing B/S/N requirements: to either make the energy backing the ICAP supplier's capacity available or notify the ISO that the capacity is unavailable so the NYISO can respond to maintain reliability. "Without the proposed requirement for an ESR, an ESR could meet its Tariff obligation and yet not make that energy available, which is inconsistent with the purpose of the requirement," the ISO said.

Failing to reflect an ESR's anticipated charging in the DAM "could cause reliability issues in real-time by not having enough resources committed from the DAM to meet actual load, reserves, and the ESRs' charging," the ISO said.

The ISO will bring the Tariff modifications to the March Management Committee meeting and hopes to make them effective with its other Order 841 compliance changes, no later than Sept. 30.

BIC OKs BTM:NG Revisions to Load Forecasting Manual

The BIC also approved the first *revisions* since 2013 to the Load Forecasting Manual, reflecting the impact of behind-the-meter net generation (BTM:NG) in the installed capacity market forecast. A BTM:NG is a BTM generator that has excess capability after serving its host load at the same location.

If a BTM:NG resource does not require power to serve load from the hour of the NYISO or locality peak, the load of the resource will not be included in the actual and weather-adjusted load in the transmission district (TD).

If the resource does require power, its load

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will be deducted from the TD's actual load and weather-adjusted load.

The forecast load of a BTM:NG resource will be based on a weather adjustment of its actual load, a projection of the load's losses and a growth rate "consistent with" that of the transmission district in which it is located, the ISO said.

"This is a little different than other loads … We normalize [transmission district loads] as a whole. But we recognize that BTM:NG might have load characteristics much different than the average load in the area," explained engineer Arthur Maniaci, the ISO's principal forecaster.

The ISO said the changes will reflect the specific weather response of each resource and is consistent with the Tariff and ICAP Manual, using the top 20 hours of each resource from within the top 40 New York Control Area hours during summer. It also mirrors current NYISO demand response processes.

The changes were developed by the Load Forecasting Task Force in 2018 and 2019 and modified after feedback from the ICAP Working Group last year.

Working During the Coronavirus Pandemic

Several stakeholders had questions about the impact of the coronavirus pandemic on ISO operations.

Mark Seibert, manager of the Member Relations team, said the ISO will provide a secondary call-in number for meetings because of heavy loads on remote meeting services that resulted in some stakeholders getting busy signals in attempting to listen to the BIC meeting.

He also said that ISO staff who interact with stakeholders were directed to forward their work phones to their cell phones to remain accessible while working from home. Stakeholders should contact Seibert or Debbie Eckels in the Member Relations team if they have difficulty reaching an ISO official, he said.

Mike DeSocio, director of market design, said ISO employees are able to access the grid operator's software systems remotely to allow continuity of operations. "Folks are able to get into the systems they need to get into and perform the work they need to perform, so we don't expect any issues there," he said. ■

— Rich Heidorn Jr.

PJM Makes MOPR Compliance Filing

By Rich Heidorn Jr.

PJM on Wednesday submitted proposed Tariff changes to comply with FERC's controversial December order requiring expansion of the minimum offer price rule (MOPR) to new state-subsidized resources.

A quick review of the 683-page filing did not reveal any major surprises (*EL16-49, ER18-1314, EL18-178*). The RTO had discussed its planned compliance filing in nine stakeholder meetings since December, including two last week. (See *PJM MOPR Floor Prices Reduced for Gas, Nuclear, Solar Units*.)

"These issues have been the subject of rigorous review and consideration of varying stakeholder interests within the time limitations allotted by the commission for the submission of this compliance filing," PJM said, noting that RTO officials also have communicated with state regulators and the Organization of PJM States Inc. (OPSI).

"PJM has heard and thoroughly considered the views of all stakeholders and representatives of states and, through this compliance filing, has attempted to balance all of the competing views on these various issues into a proposal … which is designed to meet the commission's Dec. 19 order's directives while also ensuring orderly and timely capacity auctions going forward."

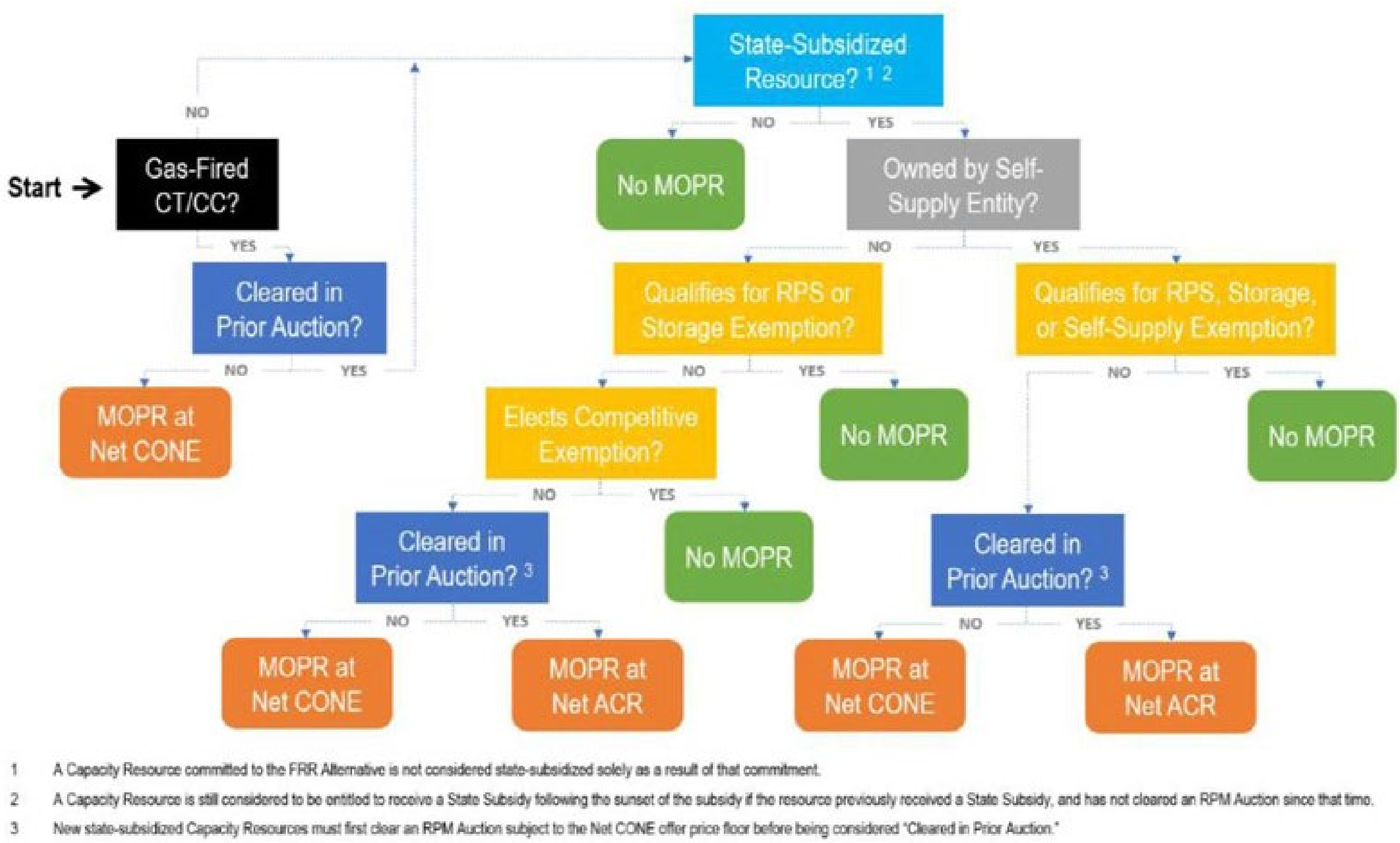
In addition to extending the MOPR to new state-subsidized resources, the rules would continue the existing MOPR on new combustion turbine and combined cycle natural gas resources.

"Where certain elements of the commission's Dec. 19 order required additional details to support the design and application of the modified MOPR, PJM has used its best efforts to add these additional detailed elements to comply with the overarching goal of the Dec. 19 order," the RTO said. "To provide market certainty, PJM will await commission action on this filing before implementing the modified MOPR in the next Base Residual Auction (BRA)."

Schedule

PJM asked the commission to allow at least 35 days for comments on its filing (no sooner than April 22). "Such an extension is appropriate given the volume of this filing and current circumstances," the RTO said. "This will afford market participants sufficient time to review and comment on the proposed changes, which is necessary given the relative importance of this filing to PJM's capacity market."

It proposed "an orderly, but compressed" auction schedule following commission action on the compliance filing, saying it would complete all pre-auction activities and open the BRA for the 2022/23 delivery year within six-and-a-half months after the commission's acceptance of the compliance filing. (See *PJM Proposes Auction for 6 Months After FERC Ruling*.)



MOPR eligibility flow chart | *PJM*

PJM News

"Capacity market sellers should know before they make concrete auction preparations, for example, the specific definition of a state subsidy, the details of available exemptions, the net CONE [cost of new entry] and ACR [avoidable-cost rate] screening values for the various resource categories, and the parameters of an acceptable unit-specific exception showing — just to name a few," it said.

Exemptions

Exempted from the MOPR would be existing resources participating in state renewable portfolio standard (RPS) programs; existing demand response, energy efficiency and storage resources; and existing self-supply resources. Federal subsidies would not trigger the MOPR.

FERC's order also provided for exemptions for resources that forego state subsidies and those that can prove through the resource-specific exception that their costs are lower than MOPR reference values.

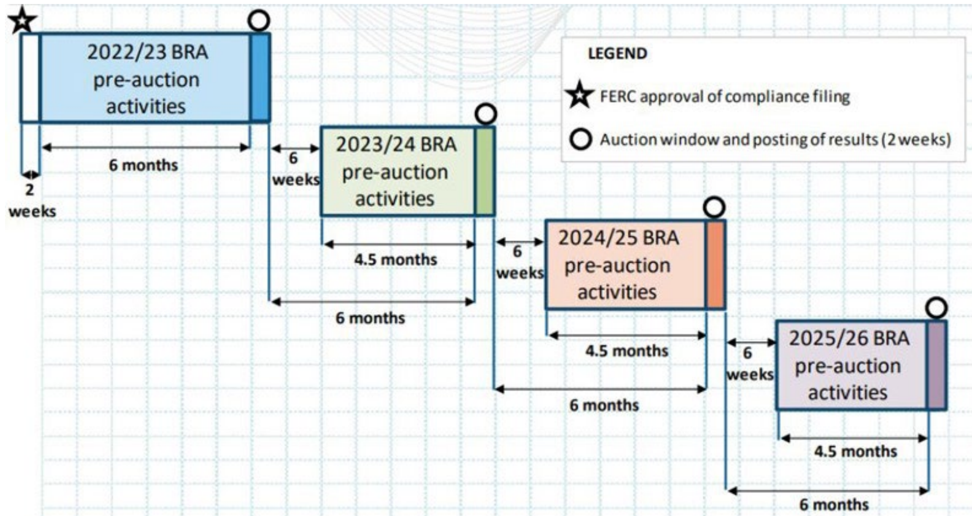
"While FERC's order combined exemptions for demand resource, energy efficiency resources and capacity storage resources, PJM proposes to separate out capacity storage resources as a separate categorical exemption given the distinctions with demand resources and energy efficiency resources," the RTO said.

It said it will offer "non-binding guidance" for capacity market sellers as to whether their resources qualify as subsidized.

"PJM and the Market Monitor will work together to develop a non-exhaustive list of programs, based on information provided by capacity market sellers, that they consider to be a state subsidy and post this list in a guidance document. Given the myriad state and local programs that may exist throughout the PJM region and the fact that such programs may change over time, it would not be practical to include a list of specific state subsidies in the Tariff," it said.

"Instead, PJM will develop and maintain, in collaboration with the Market Monitor, a list of specific state subsidies to provide guidance on many of the most common programs that may be applicable to capacity resources. Importantly, however, it is ultimately the capacity market seller's responsibility to ensure that they correctly certify whether its capacity resource is subject to a state subsidy, irrespective of any guidance provided by PJM and the Market Monitor."

It said such certifications should be subject to fraud and misrepresentation rules modeled



Proposed capacity auction schedule | *PJM*

on the provisions the commission previously approved regarding to capacity market sellers seeking a categorical exemption from the MOPR (ER13-535).

Legal Challenges Expected

FERC approved the expanded MOPR on a 2-1 vote, saying it was needed to combat price suppression from growing state subsidies, such as those for nuclear plants in Illinois, New Jersey and Ohio. Commissioner Richard Glick dissented, calling the order an attack on decarbonization efforts that would add billions in increased capacity costs.

Dozens of stakeholders filed requests for rehearing or clarification of the order, with some observers predicting the issue will end up in front of the Supreme Court. (See *PJM MOPR Rehearing Requests Pour into FERC*.)

Todd Snitchler, CEO of the Electric Power Supply Association (EPSA), whose members own and operate more than 50,000 MW of capacity in PJM, praised the filing. "Since December, there has been a productive and extensive public conversation among all stakeholders about how competitive electricity markets can best serve the interests of consumers and the power grid," he said. "PJM has worked diligently under a compressed timeline to conduct a thorough stakeholder process and develop a MOPR implementation plan while ensuring that perspectives from all relevant groups were considered and incorporated into its compliance filing. … Now, FERC must act expeditiously in order for PJM to move forward and hold its long-delayed Base Residual Auction as soon as possible."

The American Wind Energy Association also gave an upbeat review.

"PJM's proposal provides the flexibility necessary for renewable resources to demonstrate that they are among the lowest cost and most reliable sources of capacity available today," said Amy Farrell, AWEA's senior vice president of government and public affairs. "We appreciate PJM's efforts to develop sensible responses to the unsustainable policies that FERC mandated for the region's competitive market. AWEA and our members will continue working constructively with PJM to restart the capacity market and find practical solutions that recognize the value of renewable energy and protect the ability of states to control the fuel mix within their borders."

Katherine Gensler, vice president of regulatory affairs for the Solar Energy Industries Association, said that although the organization "objects to the underlying policies presented in the current MOPR construct, PJM took a positive step in proposing how to comply with FERC's December order. PJM's submission will allow renewable generators to properly identify a project-specific bid price for bidding into the capacity market auctions. This process provides renewable generators a better opportunity to compete on a level playing field with other capacity providers and to help meet states' clean energy goals.

"We request that FERC act swiftly to restore PJM's annual capacity auctions in a timely manner. Our member companies are ready to see market certainty return to PJM and to put this multi year debacle to a close." ■

PJM News

MOPR May Not be Death Knell for Renewables in PJM

IMM: MOPR Won't Impact Next BRA Prices

Continued from page 1

it "threatens states' rights and hinders their ability to bring more clean energy to their communities." The Sierra Club called it "disastrous," saying it will "essentially exclude new renewable energy resources from the PJM capacity market."

But AWEA and the Solar Energy Industries Association said last week that PJM's interpretation of the order would allow new renewable generation to clear the capacity market in the short term.

PJM's conclusion that voluntary renewable energy credits (RECs) are not state subsidies and its decision to allow an asset life of up to 35 years means that new wind and solar projects will be able to bid below the default MOPR floor values and clear the market, officials for the organizations said.

"PJM's submission will allow renewable generators to properly identify a project-specific bid price for bidding into the capacity market auctions," said Katherine Gensler, vice president of regulatory affairs for SEIA. "This process provides renewable generators a better opportunity to compete on a level playing field with other capacity providers and to help meet states' clean energy goals."

"PJM's proposal provides the flexibility necessary for renewable resources to demonstrate that they are among the lowest cost and most reliable sources of capacity available today," said Amy Farrell, AWEA's senior vice president of government and public affairs.

AWEA said that while PJM's compliance filing offers renewables short-term relief, the wind industry will be seeking long-term changes to the RTO's resource adequacy construct to ensure renewables' future.

IMM Analysis

The Monitor's analysis concluded that the new MOPR rules won't impact prices in the next BRA in part because they don't significantly change the treatment of gas-fired resources and they allow categorical exemptions for existing self- supply, demand response, energy efficiency and storage resources. It also cited the "competitiveness of unit specific offers for existing subsidized nuclear resources."

The Monitor said "although preliminary estimates of the default MOPR floor prices for new renewables are relatively high, those estimates are based on existing renewable facilities in PJM and based on standard assumptions about technologies, financing costs, capacity factors and revenues. Renewables suppliers assert convincingly that many new renewables are competitive now and will demonstrate that fact through requests for unit specific exceptions to default MOPR floor prices. Renewables suppliers also assert that they will become even more competitive in the future and for the 2024/2025 RPM BRA."

Lazard's current levelized cost of energy analysis estimates utility scale solar PV at $32-$42/MWh and onshore wind at $28-$54/MWh — well below nuclear ($118-$192/MWh), coal ($66-152/MWh) and gas peakers ($150-$199/MWh) and competitive with combined cycle plants ($44-$68/MWh).

The Monitor's analysis included a base case with current MOPR rules, offers from the 2021/22 Base Residual Auction and an adjusted supply curve to account for retirements, must-offer exceptions, projected new supply and updated offer caps for the 2022/23 delivery year. The demand curve was updated using the 2022/23 planning parameters.

The impact analysis applied the new MOPR rules to the base case supply and made no changes to fixed resource requirement (FRR) elections. The Monitor said its report did not include detailed locational deliverability area (LDA) prices or cleared quantities for confidentiality reasons.

Errors in Glick Analysis?

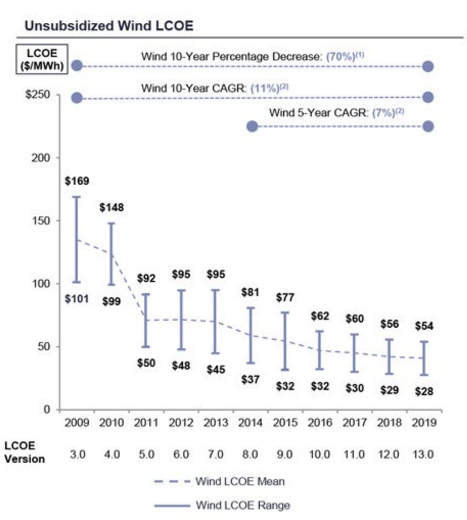
The Monitor contrasted its conclusions with analyses by Commissioner Richard Glick and consulting firm Grid Strategies, both of which predicted an expanded MOPR would add billions in annual capacity costs. "Neither are based on supportable, detailed analysis of the capacity market," the Monitor said.

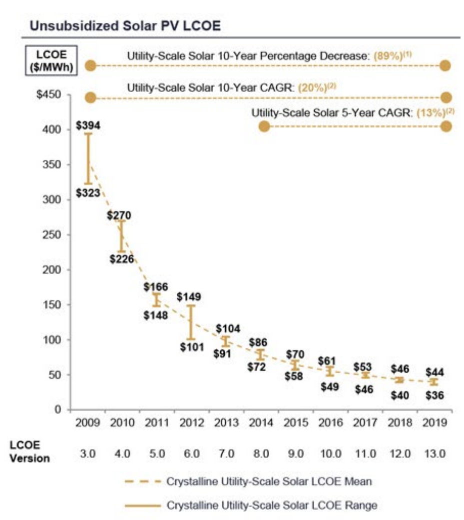
Glick dissented on the December order, calling it an attack on decarbonization efforts and warning it could increase PJM capacity costs by at least $2.4 billion annually.

The Monitor said Glick's "back of the envelope" calculation is based on an incorrect assumption on the total capacity of previously cleared nuclear power plants that receive zero-emissions credits in Illinois and New Jersey (4,837 MW, not 6,670 MW). The Monitor said Glick also incorrectly assumed the order would cut cleared demand resources by 25% when the order allowed a categorical exemption for existing DR.

The Monitor said Glick also erred in his assumptions about the slope of the demand curve and failed to adjust a baseline of 2021/22 BRA prices for changes to the supply and demand side.

"We are aware of the Bowring report and we





In the last decade, the levelized cost of energy (LCOE) for utility-scale solar has dropped by 89% and the LCOE for onshore wind has declined by 70%. | *Lazard*

PJM News

are reviewing it," Glick said via email. "I can't say more because this remains a pending proceeding and the issue is likely to be part of my consideration of the rehearing requests."

Grid Strategies Report

The Monitor also challenged Grid Strategies' *report* last August that concluded an expanded MOPR could increase capacity market prices by $5.7 billion annually, a 60% increase. Grid Strategies President Rob Gramlich repeated that estimate in *testimony* before the Illinois legislature earlier this month. (See *MOPR Impact Study Ruffles Feathers Ahead of FERC Ruling*.)

The Grid Strategies report drew "broad and incorrect conclusions [due] to a conflation of the IMM's analysis of the PJM extended resource carve out proposal (RCO) with all proposals to modify PJM capacity market rules," the Monitor said.

Gramlich said the Monitor's study cannot be verified because its "data, methods and assumptions are covered in six sentences of words with no numbers." The Monitor said details of its report cannot be published because it is based on confidential data.

Gramlich agreed that "if all of PJM's rehearing and compliance proposals are accepted by FERC, and the unit-specific process turns out favorably for clean resources, then that version of broad MOPR will likely be less costly initially than some of last year's versions. Of course, those are some big 'ifs.' And it won't change the fact that broad MOPR gets costly soon and fails the `over-mitigation' test since it is not tied to any identified market power.

"While the immediate impacts may be muted, the longer-term harm exists, and states are likely to pick up consideration of alternative options when they are able to resume policy making," he said. (See related story, *Study: Retail Design Key to Escaping Capacity Markets*.)

Mike Hogan, a senior adviser with the *Regulatory Assistance Project*, said the Monitor's report "conspicuously addresses only the impending auction, when it was clear that, due to FERC's shrewd grandfathering of the small share of existing renewable resources, the significant economic impact would grow increasingly over subsequent auctions."

Hogan, who collaborated with Gramlich on a June 2019 *report* on market designs for decarbonization, said the Monitor has "for years publicly maintained a doctrinaire and widely discredited insistence that scarcity pricing offers in the energy market should be presumed to be an abuse of market power to be suppressed unless proven otherwise, which leaves them with no option but to defend the [Reliability Pricing Model] as a way of maintaining resource adequacy. This despite the fact that while the Market Monitor has consistently found the energy market to be workably competitive, they have just as often found the RPM to have market power issues."

IMM Joe Bowring denied that he has opposed scarcity pricing. "The IMM has been and continues to be supportive of scarcity pricing as an essential element of wholesale power markets as documented in multiple FERC filings and in the State of the Market Reports," he said.

The IMM supported a different approach to the definition of competitive offers which was rejected by FERC in the MOPR order. The IMM has also published a report pointing out that the [fixed resource requirement] option referenced by Grid Strategies is likely to cost state consumers substantially more than remaining in the PJM capacity market."

Market Power Allegation

The Monitor said its conclusion that MOPR won't affect prices in the next auction does "not mean that the IMM expects that prices in the 2022/23 BRA will be unchanged from the 2021/22 BRA," noting its previous *conclusion* that market power was exercised in the 2021/22 auction. (See *IMM: PJM 2018 Capacity Auction was 'Not Competitive.'*)

The Monitor filed a complaint with FERC last year alleging PJM consumers will be overcharged by $1.2 billion for 2021/22 because PJM's market seller offer cap is too high (EL19-47). "Those overpayments would be eliminated if the commission modifies the market seller offer cap as requested," it said. PJM has disputed the Monitor's conclusions and sought to have its complaint dismissed. (See *Monitor Defends Offer Cap Complaint*.)

Will PJM's Interpretation Stand?

How renewables ultimately fare will depend in part on whether the commission accepts PJM's interpretation of the order.

The commission said that privately funded voluntary RECs cannot be distinguished from those issued under state-mandated or state-sponsored procurements.

But PJM said owners of renewable generation that generate RECs would qualify for the competitive exemption if they certify that the credits "will only be used and retired for voluntary obligations as opposed to state-mandated renewable portfolio standards." The RTO said it will modify its Generation Attribute Tracking System (GATS) to "to ensure that any capacity market sellers' self-imposed limitations on use of the RECs can be effectuated."

In their joint rehearing filing in January, the Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Sustainable FERC Project and Union of Concerned Scientists contended the unit-specific review will not prevent over-mitigation and excessive prices.

They cited the nominal levelization of gross costs, an assumed asset life of 20 years, exclusion of sunk costs and assumptions based on the economic incentives of gas units, and said the rules fail to reflect the low incremental avoidable costs of renewable resources. "Far from providing a safety valve, unit specific review is of a piece with the order's blanket exclusion of state-supported renewable resources from the capacity market," they said.

In its compliance filing, PJM said it would allow capacity market sellers to submit resource-specific justifications of an asset life other than the default 20-year assumption. It said it would cap the permissible term at 35 years, identical to the asset life assumption used in the Avoidable Cost Rate (ACR) for existing resources.

Representatives of the environmental groups said this week that PJM's filing did not resolve their concerns.

"While some renewable energy projects may be able to clear using resource-specific offer floors, that's only if developers can convince the Market Monitor that they are competitive on terms that FERC allows. And critical resources like offshore wind are almost certainly priced out," said Casey Roberts, senior attorney in the Sierra Club's Environmental Law Program.

"This conflict is not resolved if — in the near term — some renewable projects qualify with unit-specific costs," agreed UCS's Mike Jacobs.

"PJM embraces the conflict with state policies and has not addressed the problem of environmental externalities," he added. "The two sides (policy vs markets) haven't agreed on the terms of this debate. PJM and market adherents point to the cost of distorted investment signals, while policy proponents are watching for the costs of air quality and climate." ■

— Michael Yoder contributed to this article.

PJM News

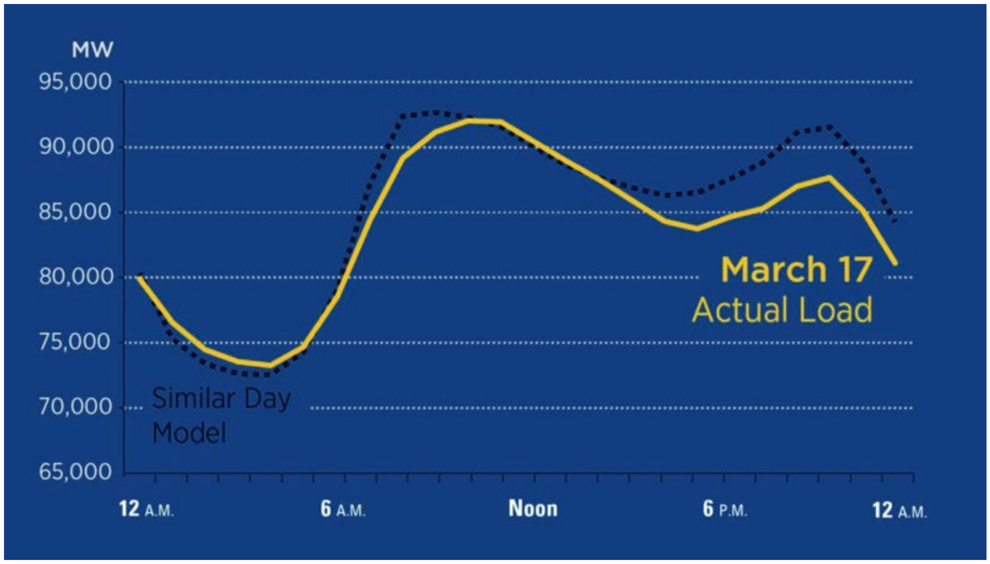
PJM to Hold Weekly Calls on COVID-19

RTO Sees Later Morning Peak, Lower Demand

By Michael Yoder and Rich Heidorn Jr.

PJM announced Monday it will hold a *weekly call* beginning Friday to update stakeholders on operational impacts from the COVID-19 pandemic. The calls, from 11 a.m. to noon, will continue until further notice.

The RTO said data from March 17 to 19 show the normal 8 a.m. morning peak has shifted to 9-10 a.m., and the evening peak is about 5% lower than expected. "The load curve also is flatter, without the same fluctuations usually shown by morning and evening peaks and valleys, when people are preparing for work in the morning or dinner at night," PJM said. "The impact so far has been noticeable, but not severe," said Michael Bryson, senior vice president of operations. "This is similar to patterns we typically see on a snow day."



PJM actual load on March 17 compared to a similar day model pre-coronavirus | *PJM*

PJM said telecommuters may be getting up later without having to commute. While commercial use of electricity is down with schools and businesses closed or operating remotely, the reductions will be partially offset by an increase in residential use.

On Monday, March 16, when PJM would normally have expected about 100,000 MW of load, it lowered its forecast to 94,500 MW. Load came in at about 95,500 MW.

PJM has implemented a work-from-home policy through April 10 for employees, with the exception of system operators and other shift personnel. Employees are also working longer shifts to minimize shift changes. The RTO said it successfully tested its work-from-home capabilities on March 13. PJM markets, planning, stakeholder meetings and member relations can all be operated remotely, it said.

Survey

On Friday, PJM opened a survey of its generation operators to identify operational risks resulting from the COVID-19 pandemic. PJM said the survey, in the eDART application, will remain open indefinitely to allow updated responses as conditions change.

The survey includes both company- and unit-level questions to identify potential delays or restrictions on fuel and consumable item deliveries and contractor and staff health concerns that may impact scheduled outages.

Example *questions*:

> **"This is similar to patterns we typically see on a snow day."**
>
> —Michael Bryson, PJM senior vice president of operations

- Are you currently experiencing any workforce impacts (either plant personnel or contractors) that could impact the unit's availability or reliability in any way?
- Regarding outages that are currently active, do you foresee any chance of needing to extend the duration of the outage to complete the work to return the unit to service?
- Regarding outages currently scheduled over the next 12 weeks but not yet started, do you foresee the need to cancel or postpone these due to contractor or resource limitations?
- Are you aware of any staffing limitations on any of your fuel suppliers, including gas pipeline operators?
- Do you anticipate any changes to any of your unit's operational parameters (e.g., emergency minimums, minimum down time etc.)?
- Is there anything PJM can do to help support any specific needs of this unit during this period?

The survey asks for ideas on best practices. "Examples could include: Segregating MOC dispatchers to multiple locations; limiting interactions between shift personnel (MOC or Plant) as much as possible; implementation of enhanced cleaning processes; evaluation of upcoming outages to determine the feasibility of deferral."

Questions on the survey can be sent to *edartgosurvey@pjm.com*.

SOS Committee Meetings

PJM's Joint System Operations Subcommittee (SOS) also is holding weekly meetings on how the pandemic is impacting generation and transmission operators.

PJM's Paul McGlynn announced plans for the meeting at the March 12 Operating Committee meeting. (See "*SOS to Meet Weekly on COVID-19 Impacts," PJM Operating Committee Briefs: March 12, 2020*.)

"I recognize that many of you are competitors in our markets … on a normal day-in-and-day-out basis," McGlynn said March 17 during a 30-minute conference call to prepare for Thursday's session. "But our industry has a

PJM News

long tradition of working together to operate the grid reliably and … keep the lights on through some pretty challenging conditions. [The weekly calls are] to get us on the same page."

The agenda for the first meeting included discussions on PJM's Pandemic Response Plan; transmission outage rescheduling; generation availability and maintenance outages; gas pipeline coordination; COVID-19 prevention best practices; and waivers that may be required due to impacts of the pandemic.

Bryson paraphrased testimony astronaut Frank Borman gave to Congress in a hearing on the Apollo 1 fire that killed three astronauts in 1967.

"The comment he made was, 'The thing we were most guilty of is a failure of imagination,'" Bryson said. "The emphasis I really want to put on this is give us any of your ideas. … We need to be thinking outside the box."

Stakeholders asked PJM to inform them of any contacts with state and federal officials and how the RTO would deal with minimum generation events caused by reduced loads from manufacturing shutdowns and office workers telecommuting.

"With the mild weather coming through right now and … this feeling almost like a weekend or a holiday, that is something we will keep looking at," promised SOS Secretary Paul Dajewski.

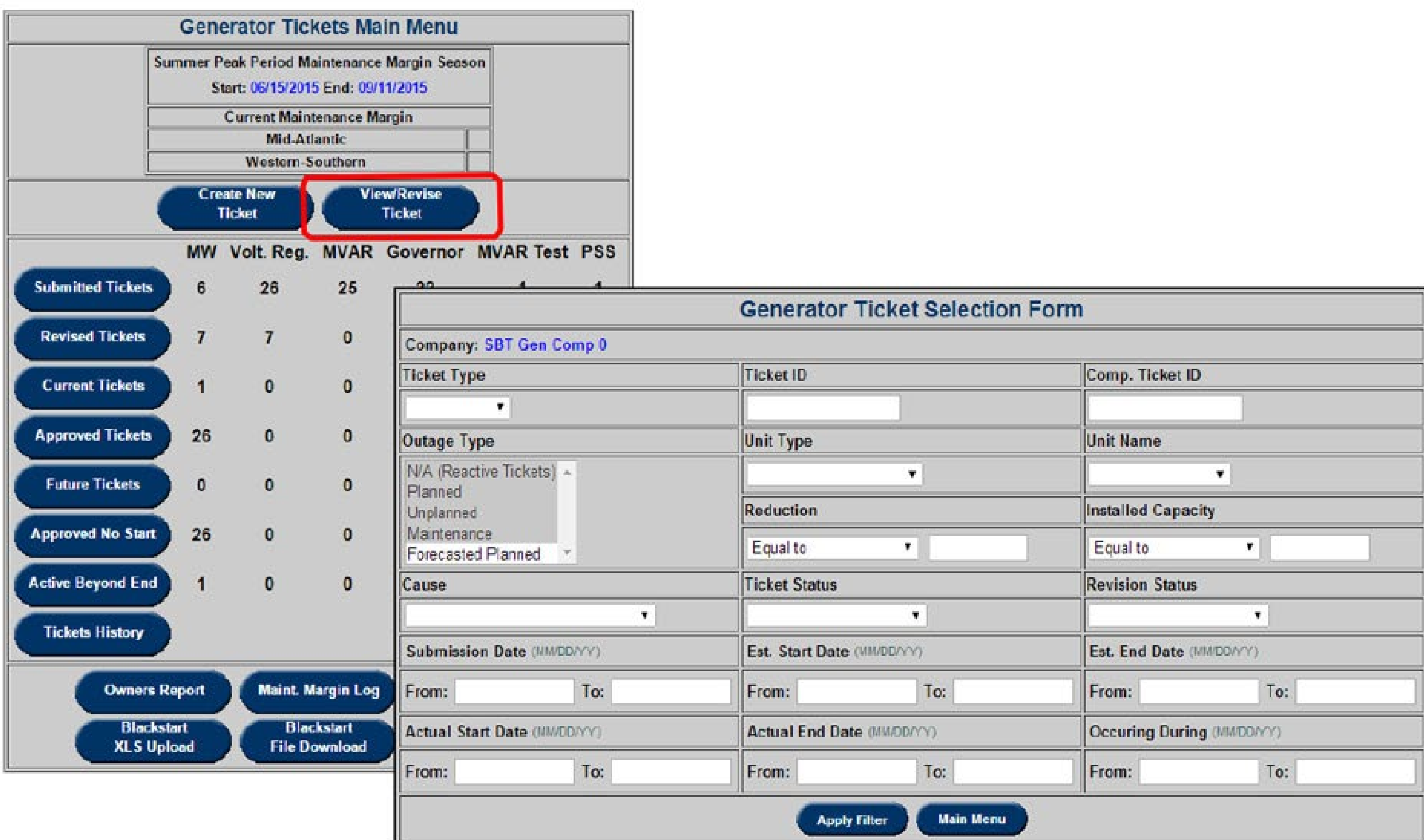
Calpine's David "Scarp" Scarpignato said generators may need "proactive action" from PJM if there are mandatory quarantines.

"If we're unable to get our contractors there to do the major maintenance that has to occur in March and April, and you put it off … into June or July, then all the sudden you need this stuff done for the generators to perform during peak [demand], [and] you're not going to have" sufficient generation, Scarp said. "It is really critical that our personnel and our contractors are considered essential personnel."

PJM announced after the meeting that it was canceling the PJM System Operator Seminar scheduled in Columbus, Ohio, from March 31 to April 24.

Bryson said companies that have operators whose NERC or PJM certifications are at risk of lapsing should contact the RTO's member training team. "We can try to work with you to try to get those [continuing education] hours," he said. "Our first approach is to push the training to maintain certification. And then if we need to do something different, we'll work with ReliabilityFirst and SERC [Reliability] and NERC to handle that.

"They will work with us," he added. ■



PJM's eDART application | *PJM*

PJM News

FERC OKs PJM TOs' Critical Tx Process

By Rich Heidorn Jr. and Michael Yoder

FERC on March 17 approved the PJM Transmission Owners' critical infrastructure mitigation plan, the subject of several months of contentious debates over complaints that it lacks transparency and improperly restricts input by stakeholders and the RTO (*ER20-841*).

The TOs' plan, which details a confidential process for removing critical transmission infrastructure from NERC's critical infrastructure protection (CIP-014) list, became Attachment M-4 to the PJM Tariff, effective March 17. Attachment M-4 allows for consultation with PJM and the affected state commissions regarding CIP-014 Mitigation Projects, including discussion of siting issues and the estimated costs of a project, subject to confidentiality safeguards.

"The proposed revisions provide a just and reasonable approach to planning CIP-014 Mitigation Projects that appropriately balances the need to maintain strict confidentiality regarding the names, locations and vulnerabilities of CIP-014-2 facilities with stakeholders' interests in transparency regarding the PJM Transmission Owners' planning of these projects," FERC said.

NERC requires TOs to protect CIP-014 assets, whose loss or sabotage could result in widespread instability, uncontrolled separation or cascading outages. Incumbent TOs say their proposal will harden these facilities — of which fewer than 20 exist within PJM's footprint — and get them off the list, improving reliability for everyone. But other sectors remain in the dark about most of the plan's details, including which assets are involved and how much it will cost.

Consumer advocates, industrial customers and state regulators asked FERC to reject the plan while trade groups WIRES and Edison Electric Institute called for approval. State consumer advocates were particularly upset that PJM endorsed the plan in a FERC *filing* despite a stakeholder resolution at the January Members Committee meeting arguing that the proposal conflicts with the RTO's Operating Agreement. (See *PJM Supports TO Critical Tx Plan*.)

FERC disagreed, saying CIP-014 Mitigation Projects are a "a subset of Supplemental Projects and therefore are appropriately planned by the PJM Transmission Owners, rather than PJM.

"In interpreting the Operating Agreement, the question is not, as protestors argue, whether a CIP-014 Mitigation Project offers a reliability benefit by removing a facility from the CIP-014-2 critical facility list, but rather whether the project is required by PJM planning criteria," the commission said. "PJM confirms, in its supporting comments, that there are no PJM planning criteria in the Operating Agreement that would allow PJM to plan CIP-014 Mitigation Projects through its RTEP [Regional Transmission Expansion Process] process, and therefore CIP-014 Mitigation Projects can be developed only as Supplemental Projects.

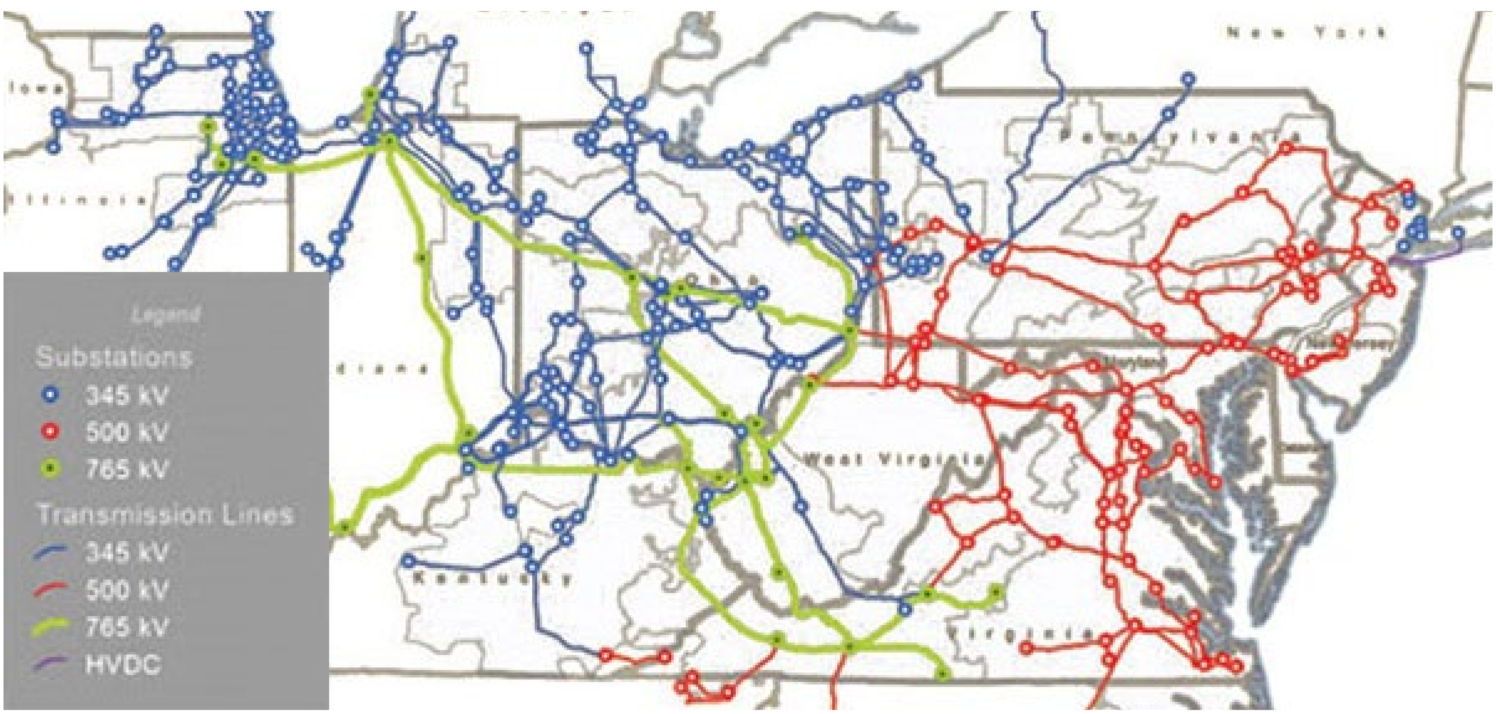
"Similarly, we disagree with protestors' arguments that PJM should implement competitive bidding procedures for CIP-014 Mitigation Projects," FERC added. "Supplemental Projects are not part of the RTEP process and thus are not part of the competitive window process."

Cost Allocation, Transparency Provisions Upheld

The commission also rejected challenges to the cost allocation of M-4 projects as beyond the scope of the proceeding.

"Although protestors raise concerns regarding the potential for double-recovery, unjustified project costs and a lack of transparency regarding the prudency of costs incurred, we find that the currently effective cost recovery process provides sufficient safeguards against these concerns," it said.

Continued on page X



PJM backbone transmission system | *PJM*

PJM News

Beaver Valley Nuclear Plant to Stay Open

Pa. Efforts to Join RGGI Cited

By Rich Heidorn Jr. and Michael Yoder

The owners of the Beaver Valley nuclear plant have told PJM they will keep the plant in operation, citing Pennsylvania's efforts to join the Regional Greenhouse Gas Initiative (RGGI).

FirstEnergy Solutions had filed a deactivation notice for the two-unit, 1,872-MW nuclear plant in Shippingport, Pa., in March 2018, targeting a 2021 retirement.

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

Energy Harbor CEO John Judge said Gov. Tom Wolf's commitment to join RGGI "will begin to help level the playing field for our carbon-free nuclear generators. In addition, our retail growth strategy now offers carbon-free energy that allows customers to meet their environmental, social and sustainability goals.

"We are excited about the RGGI process implementation in early 2022 but would need to revisit deactivation if RGGI does not come to fruition as expected," he added. Pennsylvania's Republican-controlled legislature has challenged Wolf's authority to enroll the state in RGGI. (See *Critics: Pa. RGGI Hearing Stacked with Detractors*.)

Company officials did not respond to requests for comment on the revenue impact expected from RGGI.

According to the PJM Independent Market Monitor, Beaver Valley has been profitable in all but two of the last 12 years and had a surplus of $3/MWh in 2019. The IMM projects that Beaver Valley will have a surplus of $0.91/MWh in 2020 ($13.6 million total) and $3.41/MWh in 2021 ($50.3 million).

The company said it has verbally notified the Nuclear Regulatory Commission of its rescission of the deactivations and will submit written notification within 30 days.

Beaver Valley Unit 1, which went into service in 1976, is licensed through 2036. Unit 2, which went into service in 1987, is licensed through 2047.

Energy Harbor also inherited from FES one unit at the Davis-Besse Nuclear Power Station in Oak Harbor, Ohio, and one unit at the Perry Nuclear Power Plant in Perry, Ohio. FES *withdrew* its retirement notices for Davis-Besse and Perry in July after Ohio lawmakers approved legislation subsidizing the plants. (See *Ohio Supreme Court Dismisses FES Nuke Lawsuit*.)

Beaver Valley Nuclear Power Plant

But FERC's order requiring PJM to apply the minimum offer price rule to the subsidized plants may jeopardize their ability to collect capacity market revenues going forward. (See related story, *PJM Makes MOPR Compliance Filing*.)

Perry, which began commercial operations in 1986, is licensed through 2026 but may seek a 20-year license extension. Davis-Besse, in operation since 1977, is licensed through 2037.

FES was unable to win legislative approval for subsidies in Pennsylvania. ■

FERC OKs PJM TOs' Critical Tx Process

Continued from page X

"We find that members of OPSI [Organization of PJM States Inc.] will receive sufficient information regarding the estimated costs related to CIP-014 Mitigation Projects. After submitting its preferred and potential solutions for a project to PJM, the Transmission Owner will seek a meeting with the relevant state commission(s). Upon completion of PJM's review and assessment of the CIP-014 Mitigation Project ultimately selected for construction, the Transmission Owner will again seek to meet with the relevant state commission(s) to discuss … the efficiency and cost-effectiveness of any and all of PJM's recommendations. …When public notice is provided regarding the existence of the CIP-014 Mitigation Project and cost recovery is sought, OPSI has the ability to submit a formal challenge regarding the prudency of costs associated with a CIP-014 Mitigation Project."

FERC also rejected complaints that M-4 failed to comply with Order 890's transparency provisions. "Order No. 890 allowed for flexibility in how the RTOs and transmission owning members meet these requirements for open, coordinated and transparent planning," FERC said. "CIP-014 Mitigation Projects present unique concerns related to openness and transparency. The standard non-disclosure agreements upon which PJM and the PJM Transmission Owners typically rely to protect confidential information in the transmission planning process are insufficient for CIP-014 Mitigation Projects."

Partial Dissent

FERC Commissioner Richard Glick dissented in part from the ruling, saying the mitigation projects should be planned by PJM and their costs regionally allocated because "by their very nature [they] have the potential to benefit the region as a whole."

"In my view, the better course of action would have been for PJM to plan and allocate the costs of these projects regionally, but to create whatever procedural safeguards are appropriate in light of the need to keep these critical stations and substations confidential," he continued.

Because the projects will be allocated only to customers in the zone in which each project is located, rather than in a manner commensurate with their benefits, Glick said, the proposal is unjust and discriminatory.

Glick cited a D.C. Circuit Court of Appeals ruling that "'the commission generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse.' And yet that seems to be the most likely outcome of today's order." ■

FERC Approves PJM Tx Cost Containment

By Rich Heidorn Jr.

FERC on Friday approved PJM's proposed rules on how the RTO will evaluate voluntary cost commitment proposals on competitive transmission projects (*ER19-2915*).

The Operating Agreement changes, which resulted from stakeholder-drafted motions at the Markets and Reliability Committee, require PJM to evaluate projects submitted in competitive proposal windows on multiple criteria, including "cost effectiveness." (See *PJM TOs Wary of Cost Containment Rules*.)

The revisions clarify that PJM may not require developers to submit cost containments and that those that are voluntarily proposed are binding.

PJM would evaluate "the quality and effectiveness" of provisions that limit project construction costs, total return on equity (ROE) including incentive adders or capital structure.

The RTO will submit to the Transmission Expansion Advisory Committee (TEAC) an analysis comparing the risks to be borne by ratepayers as a result of developers' binding cost commitments or non-binding cost estimates.

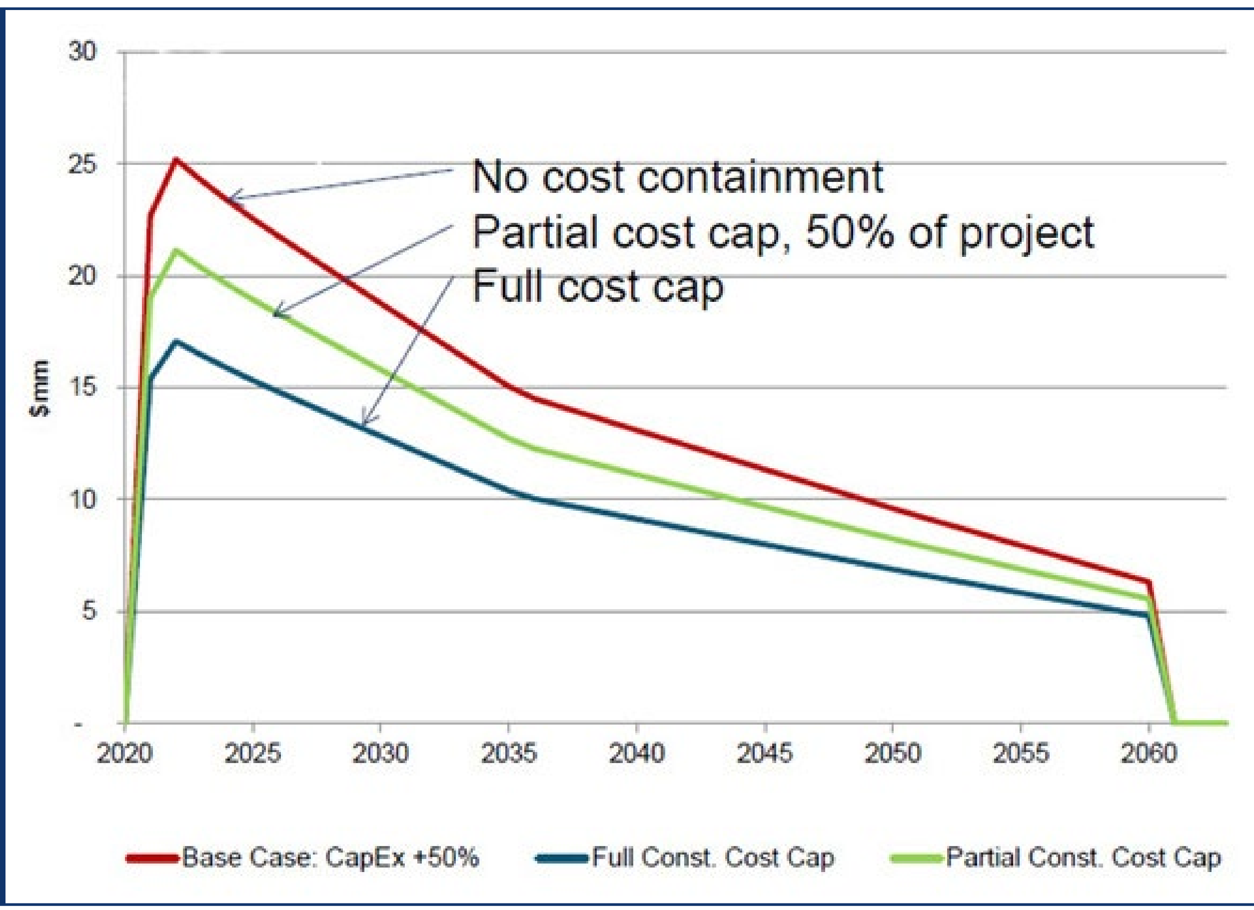
In approving the rules, the commission rejected the objections of transmission owners, which argued the revisions did not provide enough details on how PJM will conduct its comparative analysis.

"We find that PJM's filing is just and reasonable because it may assist PJM in its selection of the more efficient or cost-effective transmission solution and provides additional transparency of PJM's evaluation of competing proposals," the commission said. It noted that PJM is developing implementation details for the comparative analysis in Manual 14F.

"The proposed revisions provide reasonable flexibility both for developers to decide how to craft their voluntary cost commitment proposals and for PJM to evaluate and select the more efficient or cost-effective transmission solution. Moreover, the proposal provides for transparency, allowing stakeholders the opportunity to review any particular analysis conducted by PJM and raise any concerns via the TEAC process."

FERC disagreed with arguments that the filing infringed on the rights of PJM transmission owners and nonincumbent transmission developers to exclusively make Federal Power Act Section 205 filings concerning transmission rates, revenue requirements and cost recovery.

It also rejected contentions that PJM will be determining whether the rate design elements under a proposal will result in just and reasonable rates. "PJM is proposing for the commission to determine, in reviewing the nonconforming DEA [designated entity agreement between PJM and a selected developer] with the cost commitment provision, whether any rate design component included in that provision is just and reasonable." ■



Annual revenue requirement under partial and full cost caps | *PJM*

PJM News

FERC Sides with PJM on Pseudo-tie Challenges

Rejects Rehearing Requests by AMP, IMEA

By Michael Yoder

FERC on Friday rejected rehearing requests by American Municipal Power and Illinois Municipal Electric Agency over the commission's November 2017 order approving PJM's tougher requirements for pseudo-tied generators. The commission also approved PJM's December 2017 compliance filing required by the order (*ER17-1138*).

"The commission found that PJM's new pseudo-tie requirements would help ensure that external resources bidding into the PJM capacity auctions are comparable to internal resources in assuring that they will be deliverable to PJM's system when needed," FERC said last week. "With this principle in mind, we continue to find that PJM's proposed treatment of pseudo-tied resources is just and reasonable."

AMP's Challenge

AMP's rehearing request alleged five errors by the commission, including a challenge to PJM's decision to set the electrical distance requirement at 0.065 per-unit impedance. AMP said the commission "failed to weigh and substantiate the impact of the proposed electrical distance requirement with the level of reliability assurance" and "failed to address the relationship between the value selected as the electrical distance requirement and the impact on PJM's state estimator."

PJM said the 0.065 threshold was based on a distribution factor analysis (DFAX) to identify the external facilities that would be impacted by PJM's dispatch of external resources. PJM said the distance requirement made at least 130 GW of existing external resources in the Eastern and Midwestern U.S. eligible for pseudo-ties. The commission accepted PJM's threshold, saying it was the "result of significant analysis and requiring PJM to rely on an external resource with a higher impedance value would increase the risk to PJM's state estimator."

The commission reiterated its previous finding that the electrical distance requirement was just and reasonable "because establishing a bright-line test for external participation strikes an appropriate balance between allowing external resources to participate in PJM's capacity auctions, while providing PJM with a level of reliability assurances."

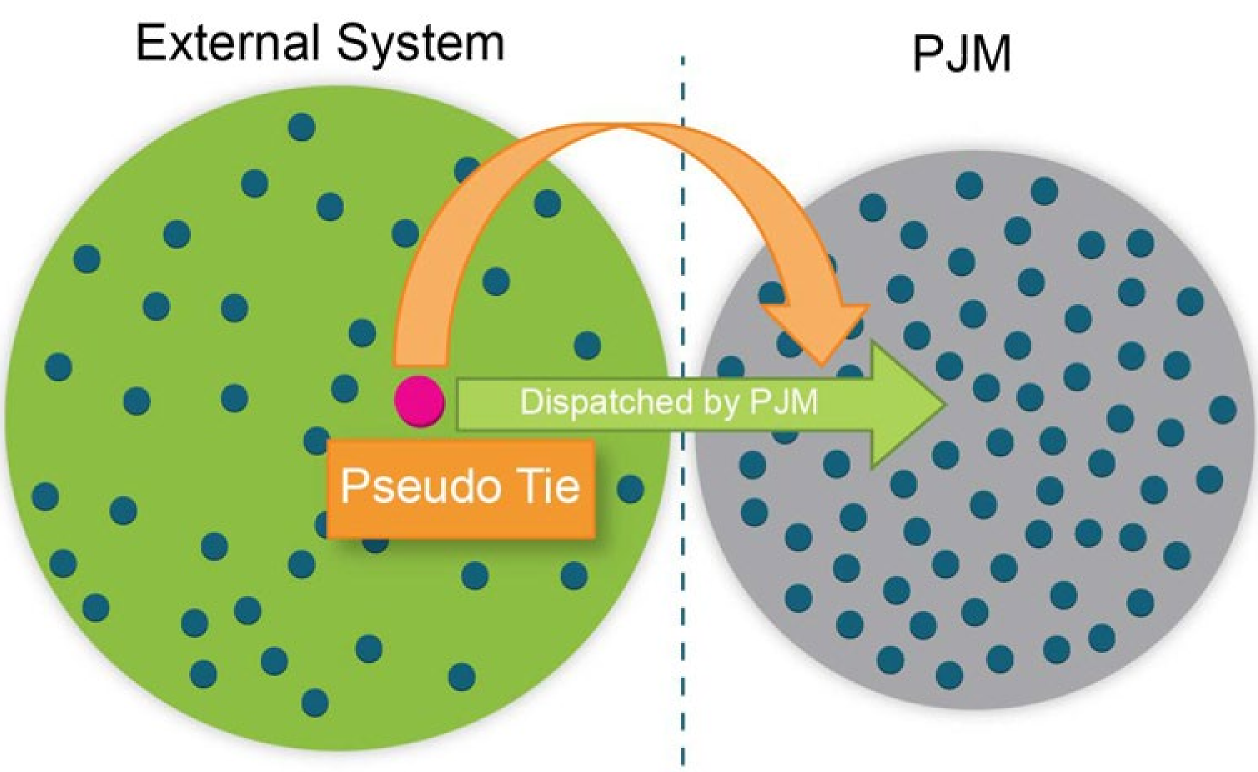
IMEA's Arguments

IMEA questioned FERC's interpretation of Section 217(b) of the Federal Power Act and whether the commission's decision "violated the sanctity of contracts."

The agency argued that the commission's determination that Section 217(b) of the FPA only applies to the energy markets and not capacity markets "effectively destroys the self-supply rights of load serving entities (LSEs)."

It said that if Section 217(b) does not apply to capacity markets, then PJM and other RTOs could make filings through Section 205 of the FPA to eliminate all "self-supply options" based on a finding that having control of all resources and planning would ensure better reliability.

FERC was unmoved. "Unlike energy markets, RTOs implement capacity markets to ensure long-term reliability and resource adequacy and, therefore, different requirements for using generation may be applied to capacity and energy markets," the commission said. ■



| PJM

MRC/MC Preview

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

RTO Insider will be covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:45-9:50)

Members will be asked to approve the following manual changes:

B. *Manual 12: Balancing Operations*. Periodic review.

C. *Manual 13: Emergency Operations*. Periodic review.

D. Manual 14A: New Services Request Process, Manual 14E: Upgrade and Transmission Interconnection Requests and Manual 14G: Generation Interconnection Requests. *Incorporating changes* related to FERC Order 845 on generator interconnection procedures and agreements.

E. *Manual 22: Generator Resource Performance Indices*. Periodic review.

F. *Manual 33: Administrative Services for the PJM Interconnection Operating Agreement*. New sections added for member roles and responsibilities and contact management and company account manager (CAM) roles and responsibilities. Existing sections relocated.

G. *Manual 37: Reliability Coordination*. Periodic review.

Endorsements/Approvals (9:50-10:35)

1. Opportunity Cost Calculator (9:50-10:05)

PJM will seek approval of a *compromise proposal* to eliminate the RTO's opportunity cost calculator and make the Independent Market Monitor's calculator the required tool for market sellers, effective June 1. The switch includes changes to Manual 15: Cost Development Guidelines to document the IMM calculator and provide for an annual review of the calculator to ensure compliance with the manual and Operating Agreement (OA). (See "PJM Seeks to Retire Opportunity Cost Calculator, Use IMM Tool," *PJM MRC/MC Briefs: Feb. 20, 2020*.)

2. Market Participation Risk Evaluation Enhancements (10:05-10:35)

The MRC will be asked to approve OA and Tariff revisions endorsed by the Financial Risk Mitigation Senior Task Force (FRMSTF) to improve the RTO's risk evaluations of market participants. At a daylong "page turn" of the proposed changes last month, some stakeholders complained that PJM was seeking excessive authority and that several of its proposed definitions were overly broad. (See *PJM Stakeholders Debate Credit Rule Changes*.)

Members Committee

Consent Agenda (1:05-1:10)

C. Members will be asked to approve *changes* to the fuel cost policy as proposed by the PJM Industrial Customer Coalition. The changes were approved by the MRC last month on a sector-weighted vote of 3.57 (71%) despite concerns that new safe harbor provisions would create loopholes permitting the exercise of market power. The new rules are spelled out in revisions to Schedule 2 of the OA and Manual 15: Cost Development Guidelines. (See *PJM MRC OKs Revised Fuel-cost Policy*.)

Endorsements/Approvals (1:10-2:00)

1. Opportunity Cost Calculator (1:10-1:20)

See description in MRC, above.

2. Market Participation Risk Evaluation Enhancements (1:20-1:45)

See description in MRC, above.

3. Elections (1:45-2:00)

A. Members will be asked to *elect* a new End Use Customer sector representative on the 2019-2020 Finance Committee to replace Mike Peters of Messer LLC, whose term expires in 2020.

B. The committee will be asked to approve on first read a *waiver* of the Manual 34 requirement that elections of board members be by secret ballot. The waiver is needed to allow use of the PJM Voting Application "due to potential exigent circumstances."

— Rich Heidorn Jr.

SPP News

SPP Launches Western Market Groups

By Tom Kleckner

An executive committee charged with overseeing administration of SPP's Western Energy Imbalance Service (WEIS) last week launched the working group responsible for developing and maintaining the market's protocols.

The Western Markets Working Group (WMWG) will report to the Western Markets Executive Committee (WMEC), which approved both the group's scope and its leadership during a March 19 conference call.

The WMWG will work with other stakeholder groups in recommending the protocols and associated Tariff changes to the WMEC and prioritizing approved system and process changes. It will also coordinate with regulators and task forces in implementing the WEIS market.

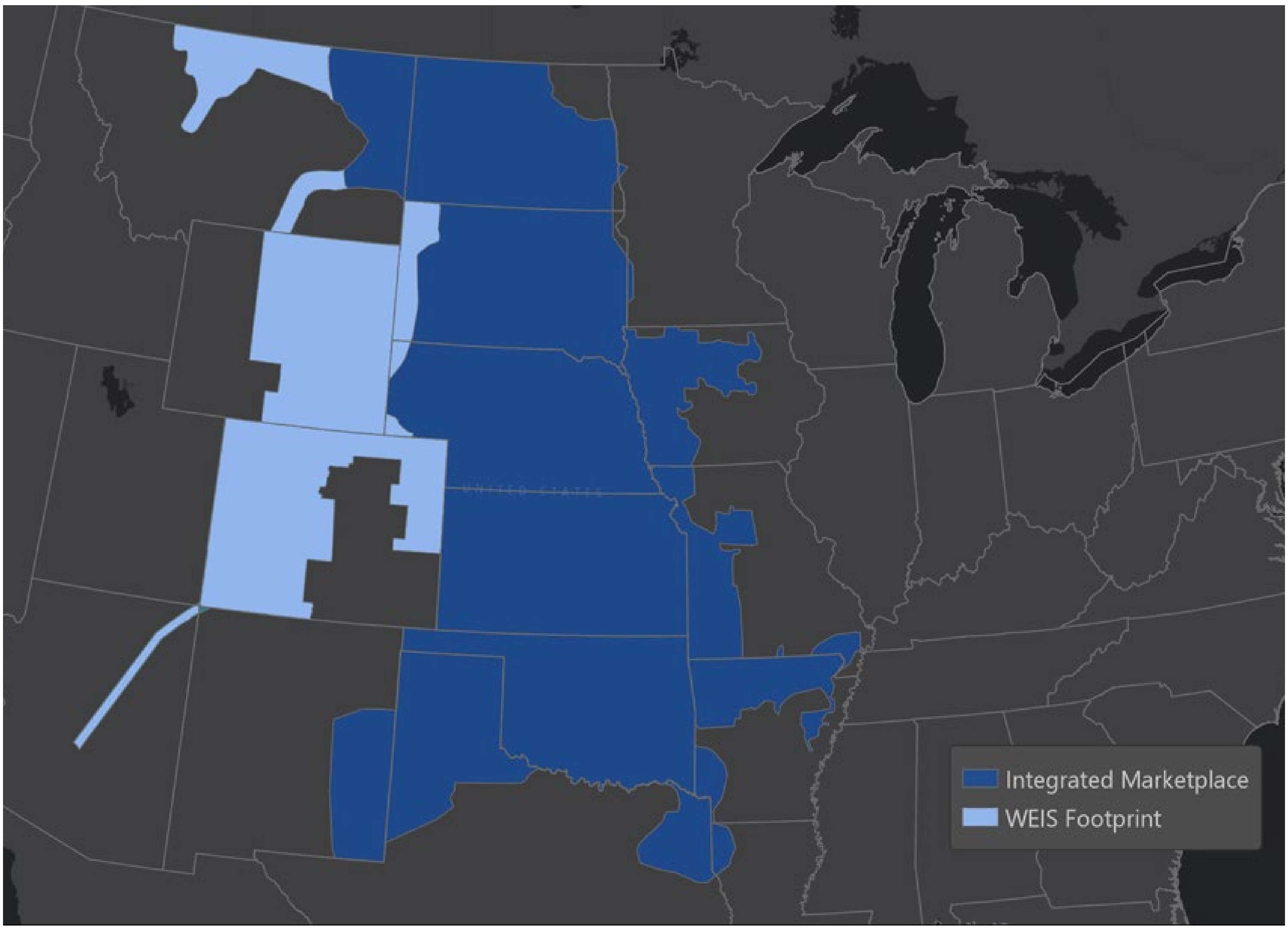
The committee unanimously approved Basin Electric Power Cooperative's Valerie Weigel as the WMWG's chair and Municipal Energy Agency of Nebraska's Jeff Lindsay as vice-chair. They will serve two-year terms.

The working group will replace the WEIS Protocol Review Task Force, which has been developing the market's *protocols*. The WMWG will consist of up to 12 members, with one representative from each non-affiliated signatory to the Western Joint Dispatch Agreement, the contractual arrangement between SPP and WEIS participants that governs SPP's obligations to administer the market and its compensation.

SPP *filed* its WEIS *Tariff* in February, asking for an effective date of Feb. 1, 2021.

The WEIS market is modeled on the Energy Imbalance Service market SPP operated from 2007 to 2014. The RTO will centrally dispatch energy from the participants every five minutes using the most cost-effective generation to reduce wholesale electricity costs for participants. SPP says the market will provide price transparency and bilateral trades.

The WEIS market has attracted eight participants with the early March addition of Utah's Deseret Power Electric Cooperative, a regional generation and transmission cooperative with six member retail systems. It is scheduled to launch next February. (See *SPP Board OKs $9.5M to Build Western EIS Market*.) ■



SPP's WEIS and legacy footprints. | *SPP*

SPP FERC Briefs

Ruling Permits Tri-State to Become FERC Jurisdictional

FERC last week accepted Tri-State Generation and Transmission Association's petition for a declaratory order that recognizes the cooperative as jurisdictional to the commission when it added its first non-utility member last year *(EL20-16)*.

The commission agreed with Tri-State's contention that the admission last September of Mieco, a wholesale energy services company that provides natural gas to Tri-State and other purchasers, made the cooperative a non-exempt jurisdictional public utility for purposes under the Federal Power Act (FPA).

FERC found that since Sept. 3, Mieco has "continuously been earning patronage capital through its sales of natural gas below index prices" and that Mieco and Tri-State have engaged in transactions that generated patronage capital — or the difference between a cooperative's yearly operating income and expenses. It said Mieco has a vote in Tri-State's operations "tailored to its status as a non-utility member," noting that although the natural gas marketer holds voting rights different from those held by utility members, the commission has not found that the FPA "requires that owners have equal levels of control to demonstrate ownership."

It said because no party provided evidence countering Tri-State's claim that Mieco is not an exempt entity under the FPA, Tri-State "has demonstrated that Mieco's rights are sufficient … to establish that Tri-State has not been wholly owned by entities exempt under [the FPA] since Sept. 3.

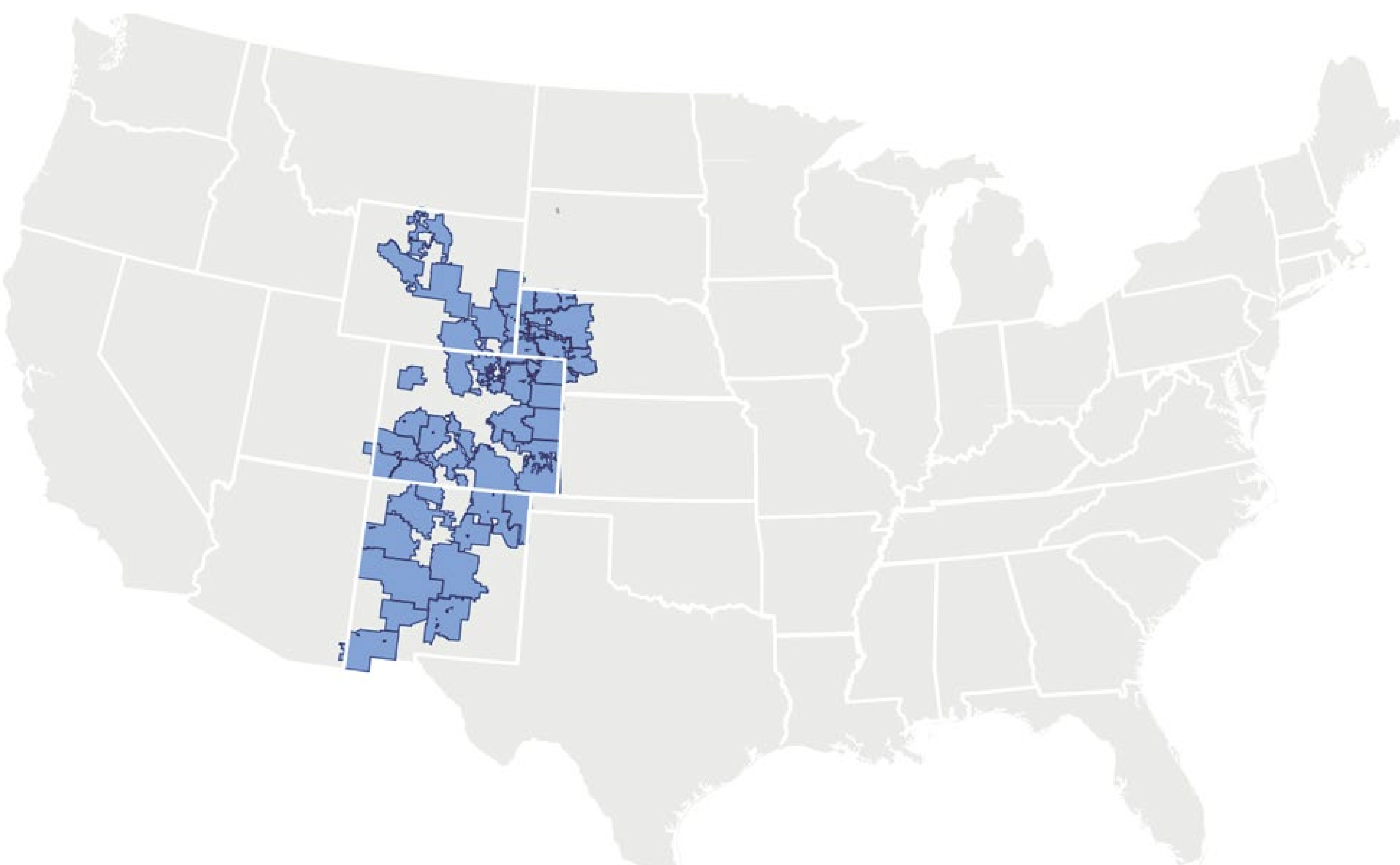
"Tri-State is grateful to FERC for its actions today and looks forward to working with FERC in a constructive manner for the benefit of Tri-State's members," Tri-State CEO Duane Highley said in a *statement*.

The company noted that it advances member flexibility for more self-supply and local renewable energy development. As part of Tri-State's *Responsible Energy Plan*, members have additional flexibility for the self-supply of power and more local renewable energy development.

Partial requirements contracts address the concerns of some members that desire self-supply above the 5% provisions in their current contracts.

Tri-State also requested relief to terminate controversy and remove uncertainty due to pending complaints filed in November before the Colorado Public Utilities Commission by members La Plata Electric Association and United Power. The cooperative said the utilities asked the PUC to "establish an exit charge [for the Member to be relieved of its obligations under its Wholesale Service Contract and exit Tri-State] that is just, reasonable, and nondiscriminatory."

FERC said that while it had jurisdiction over Tri-State's exit charges, it declined to rule that the jurisdiction is exclusive, recognizing that no federal court has found the commission has exclusive jurisdiction over "rules or practices



Tri-State G&T's service territory spans much of the Rockies. | *SPP*

SPP News

that directly affect a jurisdictional rate.

"We find that the Colorado PUC's jurisdiction over complaints before it regarding Tri-State's exit charges is not currently preempted," FERC wrote. "A ruling by the Colorado PUC on those complaints would not be preempted unless and until such ruling conflicts with a commission-approved Tariff or agreement that establishes how Tri-State's exit charges will be calculated."

Tri-State is a generation and transmission cooperative that provides wholesale electricity to 43 member electric distribution cooperatives and public power districts in Colorado, Nebraska, New Mexico and Wyoming.

Other Tri-State Requests Accepted

The commission also issued four other orders related to Tri-State's request for FERC jurisdiction that the cooperative said ensure "consistent wholesale rate regulation" for its member distribution utilities. Those orders:

- Granted Tri-State's and Thermo Cogeneration Partnership's request for market-based rate authorization. FERC denied Tri-State's request for certain waivers and blanket authorization and granted Thermo Cogen's request for waivers commonly granted to market-based rate sellers (*ER20-681*).
- Found that Tri-State and Thermo Cogen had rebutted the presumption of market power in the Western Area Power Administration's Colorado-Missouri balancing authority area and that they met the criteria for Category 2 sellers in the Northwest, Southwest and SPP regions and Category 1 sellers in the Southeast, Northeast and Central regions.
- Denied Tri-State's request for regulatory waivers and blanket authorizations, saying it does not typically grant waivers where the seller makes sales at cost-based rates.
- Accepted Tri-State's stated rate Tariff and wholesale electric service contracts and instituted a Section 206 proceeding under the FPA to determine whether the cooperative's Tariff and electric service contracts are just and reasonable. The order establishes a refund effective date, as well as hearing and settlement judge procedures (*20-676*).
- Found that Tri-State's filings raised issues of material fact that could not be resolved based on the record before it, saying they would be more appropriately addressed through hearings. It accepted the cooperative's state rate Tariff and wholesale contracts to be effective Feb. 22 and Feb. 25.
- Accepted Tri-State's Tariff and instituted a Section 206 proceeding and hearing and settlement judge proceedings (*ER20-686*).

FERC's 206 investigation will determine whether Tri-State's proposed formula rate, base return on equity (ROE), formula rate implementation protocols, reactive supply and voltage control service rates and real power loss factor are just and reasonable.

The commission also accepted Tri-State's proposed service agreements and a notice of cancellation for filing. It held two contested cancellation notices in abeyance. It rejected without prejudice a board policy that describes members' option to use self-owned or -controlled distributed or renewable generation resources to serve up to 5% of that members' requirement (*ER20-689*).

FERC also found the cooperative's board policy and generation contracts are deficient without another board policy on file that comprises specific rate mechanisms, terms and conditions that significantly affect the rates utility members must pay if they produce energy in excess of the 5% allowance. It directed Tri-State to refile the rate schedules. The commission did accept the cooperative's bylaws and other rate schedules for filing.

Commission Partially Accepts GridLiance Filing

The commission found that GridLiance High Plains' amendments to FERC's pro forma large generator interconnection agreement (LGIA) and pro forma large generator interconnection procedures partially comply with requirements of orders 845 and 845-A, requiring a further compliance filing within 120 days (*ER19-1961*).

The commissioners said GridLiance's proposed revisions regarding the option to build transmission partially comply with the orders' requirements because they incorporate most of their language without modification. However, FERC found that GridLiance had not justified its proposal to retain language of its pro forma LGIA that the commission removed from FERC's pro forma LGIA in the revisions set forth in the orders.

The language at issue provides that the "interconnection customer shall so notify transmission provider within 30 calendar days" as required by orders 845 and 845-A.

FERC issued orders *845* and *845-A* in 2018 and 2019, respectively, to increase the transparency and speed of generator interconnection processes. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections* and *'Boring Good' Rulemaking Seeks to Clean up Order 845*.) ■

— Tom Kleckner

Company Briefs

FERC Gives Partial OKs on Order 845 Compliance

FERC last week partially accepted Order 845/845-A compliance filings by six transmission owners in the West. The companies were ordered to make additional filings to address issues including the option to build and the methods for determining contingent facilities and provisional interconnection service.

The commission ruled on compliance filings by GridLiance High Plains (*ER19-1961*); Idaho Power (*ER19-1936*); NV Energy (*ER19-1904*); Puget Sound Energy (*ER19-1947*); Sky River (*ER19-2112*); Western Interconnect, LLC (*ER19-2165-001*).

The commission also granted a waiver of Order 845/845-A for Alcoa Power Generating's limited transmission facilities (*ER19-1965*).

MISO, SPP Agree to Conduct 2020 Joint Study

MISO and *SPP* staff last week agreed to perform a joint study in 2020, keeping hope alive that the RTOs will agree on an interregional project.

The RTOs' Joint Planning Committee, comprised of staff from both MISO and SPP, voted unanimously during a March 19 conference call to perform a coordinated system plan (CSP) this year. The approval clears the way for the CSP's scope development. Initial portfolios are scheduled to be filed by each grid operator in August.

Staff have identified 10 congestion areas they believe need further evaluation. The areas were selected based on their level of congestion and shadow prices, which both RTOs use to identify economic congestion issues.

Three previous CSPs have failed to come up with a mutually agreeable joint project. The criteria for interregional projects have since been revised to eliminate a "triple hurdle" of requirements.

More: *MISO, SPP Staff Recommend 2020 Joint Study*

EDF, ODEC Developing Solar in VA, DE and MD

Old Dominion Electric Cooperative (ODEC) and EDF Renewables N.A. last week announced they will develop 15 solar projects totaling 60 MW across Virginia, Maryland and Delaware. They are expected to be in service sometime next year.

EDF will develop the projects while ODEC will buy the power at a fixed rate through power purchase agreements. The new deal expands a contract ODEC signed with EDF in 2019 for 30 MW of solar across as many as 12 sites.

More: *Power Engineering*

NIPSCO Depreciation Calculation Set for Hearing

FERC last week ordered hearing and settlement procedures on Northern Indiana Public Service Co.'s proposed calculation of depreciation, saying it may not be just and reasonable.

NIPSCO tapped Gannett Fleming Valuation and Rate Consultants, which used an "equal life group" procedure for depreciation, where NIPSCO's assets are subdivided according to service life. But FERC said the procedure approach may not be appropriate and called for a fuller examination of the method in a hearing.

More: *(ER20-855)*

SWEPCO Nears Deal for Influx of Wind Power

Southwestern Electric Power Co. (SWEPCO) last week announced it reached a deal with the Louisiana Public Service Commission, the Alliance for Affordable Energy and Walmart to add 810 MW of wind energy to the utility's generation capacity.

FERC has approved plans by SWEPCO and sister company Public Service of Oklahoma (PSO) to acquire three wind farms in Oklahoma known as the North Central Energy Facilities. The Oklahoma Corporation Commission approved PSO's plan to add 675 MW of wind on Feb. 20.

The destination for the rest of the wind farms' output will depend on rulings by Louisiana and Arkansas regulators. States that approve the project would have the ability to increase the MW allocated to them if a third state turns down the proposal.

More: *SWEPCO*

Utilities Continue with Shutoff Suspensions

The Edison Electric Institute announced last week that all EEI member companies are suspending shutoffs over non-payments due to the COVID-19 coronavirus pandemic. "This crisis will create significant financial hardships for many Americans, and we know that now, as always, ensuring access to reliable electricity is essential to the health and safety of all our customers," EEI President Tom Kuhn said. "To help reduce the impact of the crisis on the most vulnerable, EEI members are committed to working collectively with our state public utility commissions to appropriately suspend power shut-offs for non-payment."

Ameren Illinois and Indianapolis Power & Light last week said they will suspend disconnection of services for nonpayment until May 1 and April 15, respectively. DTE Energy will do the same for low-income customers through April 5. Alliant Energy also said it will do the same for its Iowa and Wisconsin customers but did not specify an end date.

Pacific Gas & Electric said its workers will continue to respond to service problems during the Bay Area's three-week shelter-in-place order but will suspend all system upgrades that could cause outages for the next three weeks.

More: *WISHTV*, *WGEM*, *ClickonDetroit*, *The Mercury News*, *KIMT*, *EEI*

Federal Briefs

Clean Energy Sector Seeks Subsidy Help to Confront Slowdown

In a letter to House and Senate leadership last week, seven clean energy trade groups including the American Wind Energy Association asked lawmakers to extend deadlines for projects to qualify for wind and solar federal tax credits. The letter said disruptions caused by the spread of the coronavirus could put 35,000 jobs at risk and threaten $43 billion in investment.

Solar projects currently qualify for a credit of 26% (due to drop to 22% in 2021). If companies start construction or spend 5% of a project's cost by the end of the year, they will be eligible for the credit. Wind projects can claim a credit worth 1.5 cents for every kWh if they break ground before Jan. 1, 2021. The industry is asking for those deadlines to be extended, and for the credits to be available for direct pay, meaning they could be converted to cash.

More: *Reuters*

Solar Led Generation Additions in 2019

Solar energy accounted for 39.8% (13.3 GW) of all new electric generating capacity in the U.S. in 2019, its highest share ever and more than any other source, according to the U.S. Solar Market Insight 2019 Year-in-Review report. It is the second time solar was the leading source of new capacity, and the first since 2016. Natural gas (32%) and wind (27%) were second and third, respectively.

The report finds the U.S. solar market grew by 23% from 2018. Furthermore, the total installed PV capacity is projected to rise by 47% in 2020, with nearly 20 GW of new installations expected by the end of the year. Each of the next two years are expected to be the largest on record for the country's solar industry.

The residential sector saw record-setting installation totals as well, with more than 2.8 GW installed.

More: *Solar Power World*, *GreenTech Media*

N.M. Delegation Seeks More Time for Input on Nuclear Fuel Proposal

Citing the coronavirus pandemic, members of the New Mexico congressional delegation asked the Nuclear Regulatory Commission to extend the 60-day public comment period on an environmental review of a complex that would house spent nuclear fuel from commercial power plants. The NRC recently issued a preliminary recommendation in which it favored approval of a license for Holtec International to build the facility in southeastern New Mexico.

The NRC staff's preliminary recommendation stated that there were no environmental impacts that would preclude the commission from issuing a license for environmental reasons and was based on a review of Holtec's application and consultation with local, state, tribal and federal officials. However, Gov. Michelle Lujan Grisham and others have concerns about the potential environmental effects and the prospects of the state becoming a permanent dumping ground for spent nuclear fuel.

More: *The Associated Press*

TVA Submits RFPs for Renewables

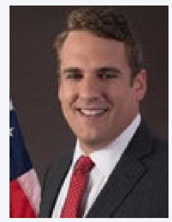
The Tennessee Valley Authority (TVA) last week issued a request for proposals (RFPs), due by April 24, to develop 200 MW of renewable energy projects that can be brought online by the end of 2023.

TVA procured more than 1.3 GW of energy through similar RFPs in 2018 and 2019. In 2018, the company reached an agreement with two developers to design the largest solar installations in Tennessee and Alabama at the time. Then, earlier this month, TVA announced it had contracted 484 MW of solar, including a 200-MW plant paired with a 50-MW battery system.

TVA expected to announce the selected proposals this fall.

More: *PVTech*

Watchdog Raises Concerns Over Danly



Watchdog group Accountable.US is spotlighting concerns about newly confirmed FERC Commissioner **James Danly** and his connections to two projects the agency regulates.

According to ethics forms obtained by the group, Danly worked at a law firm from 2014 to 2017 and had Exelon and NextEra Energy as clients. Both companies have ongoing natural gas projects, which the agency has jurisdiction over under the Natural Gas Act. NextEra US Gas Assets, a subsidiary of NextEra, is the part-owner of the proposed Mountain Valley Pipeline project in Virginia and West Virginia, while Exelon partially owns the proposed Annova LNG export facility in Texas. Both projects had environmental question raised about them last year.

"There is clearly a conflict of interest in these cases," said Chris Saeger, Accountable.US's director of strategic initiatives. "And I think the fact that (the projects) have already been approved with little transparency as to his involvement in these projects is incredibly disturbing."

More: *The Hill*

State Briefs

ARKANSAS

Entergy Arkansas Announces Rate Reduction

Entergy Arkansas said last week that its customers will see a bill reduction for a second straight year, with the typical residential customer using 1,000 kW saving $4.10 per month. The rate cut is in addition to a $4.20 reduction that took effect in April 2019.

Reasons for the reduction include lower gas prices, projects that have improved the performance of Arkansas Nuclear One, and transmission upgrades that have helped alleviate congestion.

More: *Arkansas Business*

CONNECTICUT

Pandemic Prompts Request to Delay Renewable Bid Deadline

Brian Farnen, general counsel for the state's

Green Bank, last week asked the Public Utilities Regulatory Authority to extend the deadline from June 12 to July 12 for bids in the state's renewable energy credit and shared solar programs.

Farnen said extending the deadline during the coronavirus crisis would allow more bidders to participate and drive down prices for ratepayers. At the same time, Farnen said a 30-day delay isn't too long that it will penalize developers who are ready to submit.

It will be the ninth round of bid solicitations under the utility-managed, low-emission and zero-emission renewable energy certificate program.

More: *Energy News Network*

INDIANA

Richmond Solar Park Gets Final Approval

The Richmond Advisory Plan Commission unanimously approved a zoning change for an Indiana Municipal Power Agency (IMPA) solar park that will consist of 55,000 panels on 75 acres.

IMPA had to get city approval for the project because the land had to be rezoned from dense residential to institutional zoning.

Construction is expected to start late this year or early next and finish up by the end of 2021.

More: *Richmond Palladium-Item*

MAINE

CMP Power Line Project Wins Initial Approval from DEP

The Department of Environmental Protection (DEP) last week issued a draft permit for Central Maine Power's $1 billion New England Clean Energy Connect Project. The approval comes more than a week after officials said expansion opponents had gathered enough signatures for a referendum on the project in November.

The draft order requires a 54-foot corridor width; preserving the natural forest canopy or trees at least 35-feet tall along a specific 14-mile segment; conserving more than 700 acres of deer wintering area along the Kennebec River; and prohibiting herbicide use for the first 53.5-mile segment from the Canadian border to the river. The order also requires CMP to conserve 40,000 acres of forest in western Maine and provide $1.8 million for a culvert replacement program meant to improve fish habitat and water quality and prevent erosion.

The DEP said it will review and consider all written comments before making its final decision.

More: *Portland Press Herald*

Regulators Approve Emera Maine Sale

The Public Utilities Commission last week approved the $1.3 billion sale of Emera Maine to Enmax, a Canadian utility company. The sale is expected to close this week.

The approval comes after a settlement was reached between Enmax, Emera Maine, the Office of Public Advocate and other parties. The settlement includes rate credits for customers totaling $8.1 million and a freeze on rate increases until October 2021.

More: *Portland Press Herald*

MASSACHUSETTS

State Set to Launch Clean Peak Standard

The Department of Energy Resources last week filed with the state legislature its Clean Peak Standard regulations, which will now go through a 30-day review period. Massachusetts will be the first state to enact such measures when it is expected to take effect in June.

The bill creates credits for clean energy delivered during peak hours for a given season. Utilities must obtain clean peak credits equal to a percentage of total electricity delivered in the year, starting at 1.5% this year and growing annually. The goal is to create a price signal to shift clean power to the hours it's most valuable.

More: *GreenTech Media*

MINNESOTA

High Court to Review Nemadji Trail Environmental Review

The state Supreme Court last week agreed to review a Court of Appeals decision that found the Public Utilities Commission should have considered the environmental effects of building the proposed Nemadji Trail Energy Center when it advanced the project in October 2018. The ruling could force regulators to conduct a new environmental review of the project, resulting in a significant delay.

Minnesota Power, which would own the plant, argued that because the plant would be in Wisconsin, the appeals court had overstepped its authority in ordering an environmental analysis. The Supreme Court has yet to set a date for oral arguments.

The project, which received approval from the Wisconsin Public Service Commission in January, still faces a plethora of hurdles that could derail construction. Despite the Wisconsin PSC's approval, the project needs to secure permits from the Wisconsin Department of Natural Resources, the city of Superior and the U.S. Army Corps of Engineers.

More: *The Daily Reporter*

MISSOURI

Supreme Court Upholds Decision on Grain Belt Express

The state Supreme Court last week upheld the Court of Appeals Eastern District's 2019 decision reaffirming the Public Service Commission's approval of a certificate of need and necessity for the Grain Belt Express Project. The ruling ends an effort by opponents to overturn the PSC's decision.

The $2.2 billion project would run 780 miles from western Kansas across Missouri, Illinois and Indiana where it would connect to the Eastern power grid.

More: *KTTN*

NEVADA

State to Adopt Energy Storage Target

Nevada became the sixth state in the U.S. to deploy an energy storage target last week, as it aims from 1 GW by 2030.

The Public Utilities Commission adopted a permanent regulation which shoots for 100 MW by the end of this year and increases by 100 MW each year for the next 10 years. It was adopted after more than two years of deliberation since the investigation and rulemaking docket was opened by the commission in August 2017.

More: *Energy Storage News*

OREGON

Jordan Cove Gets Federal Approval but State Permit Denials Remain

FERC's 2-1 decision last week to approve the Jordan Cove LNG project does not

mean the project can move forward because Pembina Pipeline Corp. still needs to qualify for state permits. Three of those permits have so far been denied for the project, which includes a 229-mile natural gas pipeline, liquefication plant and shipping terminal.

Last month the Department of Land Conservation and Development (DLCD) objected to Pembina's pursuit of a permit to build in the state's Coastal Zone. The Department of Environmental Quality also denied a clean water permit and caused Pembina to withdraw its permit applications to the Department of State Lands.

The DLCD said the project would have significant adverse effects on state lands and determined the project was not consistent with the state's land use laws, It said neither FERC nor the Army Corps of Engineers "can grant a license or permit for this project unless the U.S. Secretary of Commerce overrides this objection on appeal." Even if the commerce secretary were to overturn the state's land use decision, it's not clear the project could obtain a water quality and dredging permit. A 2019 report determined that if the project gets built, it will become the largest greenhouse gas emitter in the state.

More: *The Oregonian*, *Oregon Public Broadcasting*

SOUTH DAKOTA

PUC Approves New Wind Farm

The Public Utilities Commission last week approved a construction permit for Xcel Energy's $380 million Dakota Range wind project, which will consist of up to 72 turbines across 44,500 acres.

The permit includes conditions addressing issues including bird mortality monitoring and aircraft detection lighting.

The project is expected to be finished in 2021.

More: *The Associated Press*

Two Crowned Ridge Wind Projects Get State Support

The Public Utilities Commission (PUC) last week unanimously approved two Crowned Ridge Wind projects being developed by NextEra Energy Resources.

The PUC's first decision was denying the revocation of a permit for the 300-MW Crowned Ridge Wind project in Codington and Grant counties. The commission granted the permit on July 26, but it is now being appealed in the state Circuit Court over sound, shadow flicker and avian-study issues. Commission staff requested the revocation be denied or receive no action in February, saying it didn't have jurisdiction to make the ruling.

The second decision was the approval of a permit for the 300-MW, 132-turbine Crowned Ridge Wind II project in Codington, Deuel and Grant counties.

More: *Keloland Media Group*

TENNESSEE

Knoxville Signs Agreement with TVA

The Knoxville Utilities Board (KUB) last week voted to approve a 20-year purchase power agreement with the Tennessee Valley Authority (TVA). Financial terms of the deal were not released.

As part of the agreement, TVA will provide a 3.1% rebate and save the city-owned utility $9.5 million a year. It will also help support the city's plan to build its own 212-MW solar farm projected to supply about 8% of KUB's annual electric load. Meanwhile, KUB will build the solar generating facility under TVA's Green Invest program to help meet the renewable goals of private companies wanting to buy only renewable power.

More: *Chattanooga Times Free Press*

TEXAS

Capital Power Agrees to Wind Deal

Capital Power

Canadian energy company Capital Power Corporation last week agreed to acquire the 100-MW Buckthorn wind farm from unnamed private investors for $60-$69 million. The purchase price range is dependent on the realization of future market performance and entering a tax equity partnership.

Buckthorn began commercial operation in January 2018 and features 29 Vestas turbines.

The deal is expected to close in the second quarter and is subject to regulatory approval.

More: *Renews*

WASHINGTON

Regulators Deny Avista Replacement Power Request

The Utilities and Transportation Commission last week said that Avista ratepayers will not be responsible for covering $3.2 million in costs for replacement power tied to the temporary shutdown of the Colstrip plant in September 2018.

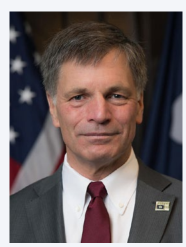
The plant exceeded federal emission standards in June 2018, forcing Avista, PacifiCorp and Puget Sound Energy to seek additional supplies during a partial shutdown. Commissioners said the utilities did not provide enough documentation to show they would have been unaware of the abrupt loss of energy since the plant tested at the allowable limit of pollutant standards in February 2018 following two years of testing well below. That should have served as a warning sign, the commissioners argued.

However, the commission will allow Avista to seek compensation for roughly a $500,000 worth of maintenance work and construction due to the outage.

More: *The Spokesman-Review*

WYOMING

House Bill Aims to Replace Retiring Sources with Small Nuclear Reactors



The state legislature last week passed House Bill 74, which would allow utilities and other power plant owners to replace retiring coal and natural gas plants with small modular nuclear reactors (SMRs). The bill easily passed both the Senate (29-1) and the House (56-3). The bill has been sent to Gov. **Mark Gordon**.

HB 74 would allow coal or natural gas plant owners to apply to replace the plants with SMRs up to the current capacity of the retiring plant. Although SMRs are defined as having a capacity of no more than 300 MW, the bill will allow multiple SMRs to be installed at the same site, so their combined capacity equals the capacity of the plant.

More: *JD Supra*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