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## PSEG, EXELON PUSH CAPACITY EXITS FOR NJ, ILL.

# PSEG Turns Bullish on NJ FRR Option

By Rich Heidorn Jr.

PSE&G has suspended nonessential fieldwork while continuing emergency work during the coronavirus pandemic.| *PSE&G*

Public Service Enterprise Group CEO Ralph Izzo said last week it would be "logical" for New Jersey to abandon the PJM capacity market by adopting the fixed resource requirement (FRR) option.

The New Jersey Board of Public Utilities opened a proceeding to consider the FRR option in response to FERC's December order expanding the PJM minimum offer price rule (MOPR) to all new state-subsidized resources — including PSEG nuclear

*Continued on page 24*

# Clock Ticking on Exelon Illinois Nukes Under MOPR

By Michael Yoder and Rich Heidorn Jr.

Kathleen Barrón, Exelon | *© RTO Insider*

Exelon officials told investors Friday the company's Illinois nuclear plants are "up against a clock," with the state legislature unable to meet to consider proposals for withdrawing from PJM's capacity market.

Illinois officials have been discussing leaving the market over the minimum offer

*Continued on page 26*



# Exelon Bid to Keep Mystic Units Running Provokes Outrage

By Michael Kuser and Rich Heidorn Jr.

When Exelon announced that it would retire its 2,001-MW Mystic Generating Station, ISO-NE was forced to amend its Tariff and sign an expensive and controversial out-of-market contract to keep the plant running through May 2024 for reliability.

Now, Exelon has filed interconnection requests to keep the two combined cycle units at the plant in Everett, Mass., running beyond the end of its $400 million cost-of-service agreement for "fuel security" in 2024. Exelon's April 20 filing with ISO-NE asked the RTO to treat the two gas-fired units — with a combined capacity of 1,600 MW in summer and 1,700 MW in winter — as "new" resources.

*Continued on page 12*

## COVID, WARM WINTER DENT UTILITY Q1 EARNINGS

Some utilities are revising their 2020 earnings targets as a result of the coronavirus pandemic while others are leaving them unchanged. Meanwhile, SPP extended its work-at-home rules through July.



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# In this week's issue

# FERC/Federal News

# DC Circuit Skeptical of NARUC Challenge to FERC Order 841

*By Michael Brooks*

A three-judge panel of the D.C. Circuit Court of Appeals did not seem particularly convinced last week by state regulators' and utilities' arguments that FERC exceeded its jurisdiction when it issued *Order 841*.

Representing the National Association of Regulatory Utility Commissioners, Jennifer Murphy told the judges on May 5 that FERC had violated provisions of the Federal Power Act that protected states' authority over their local distribution systems with Order 841. Issued in February 2018, the order directed RTOs and ISOs to revise their tariffs to allow energy storage resources full access to their markets. (See *FERC Rules to Boost Storage Role in Markets*.)

Murphy said NARUC is supportive of the order except for "one small, unnecessary aspect," in which the commission asserted that states could not prohibit storage resources on the distribution side from selling their power into wholesale markets. Along with Dennis Lane — representing organizations including the American Public Power Association and Edison Electric Institute — Murphy cited *FPA Section 201b*, which says FERC "shall not have jurisdiction ... over facilities used in local distribution."

Lane said that interconnecting distributed storage to the bulk electric system could require upgrades both to utilities' distribution and transmission systems. "Our concern as distribution utilities is what adjustments we are going to have to make ... to the distribution system to allow [a storage owner] to" sell wholesale power, he said. The distribution system "is assigned exclusively to states" under the FPA.

Judge Merrick Garland cited *FERC v. EPSA*, in which the Supreme Court overruled the D.C. Circuit and upheld FERC's jurisdiction over demand response resources through Order 745. The D.C. Circuit had ruled that, because DR was a retail product, it was not subject to federal regulation. (See *Supreme Court Upholds FERC Jurisdiction over DR*.)


AES battery storage | *AES*

But Murphy said 745 allowed states to "opt out" and prevent DR resources from participating in the markets, which the Supreme Court had noted made it in compliance with Section 201b, contrary to the Electric Power Supply Association's claims. "The issue in the *EPSA* case was the actual setting of [wholesale rates]; the opt-out happened beforehand, and the courts have said it is only an incidental effect if you're changing the amount of [what is] participating in the [wholesale] markets," she said.

Lane also noted that in *EPSA*, the Supreme Court had agreed with the D.C. Circuit that FERC could not regulate practices that indirectly affected wholesale rates and had noted that the commission had acknowledged this limitation when it issued 745.

Judge Robert Wilkins said, however, that if the petitioners' "argument was correct, the opt-out wouldn't fix the problem, because your argument is essentially that FERC can't mandate the use of these behind-the-meter storage facilities. ... It doesn't matter if they give the states the ability to opt out of the mandate. Your argument is that they don't have the power to do that in the first place."

"Well, Judge Wilkins, I don't want to sound facetious, but we're pretty practical people," Lane said, "and if they did an opt-out, we wouldn't be raising this issue."

"Although claiming the ability to negate such state decisions, the commission chose not to do so in recognition of the linkage between wholesale and retail markets and the states' role in overseeing retail sales," the Supreme Court wrote in *EPSA*.

Lane argued that the court had not addressed the question of whether the opt-out clause in 745 was legal under the FPA, only that it belied EPSA's arguments of infringement on state authority. "We're asking you now to address this question," he said.

### Standing?

The judges also questioned whether the petitioners had standing in the case. Wilkins noted that no request for rehearing of the order made the argument that Lane had about *EPSA*. He also noted that none of the petitioners had made the argument that FERC exceeded its authority in their opening briefs. They had only argued that the order adversely affected

# FERC/Federal News

states' ability to regulate their distribution systems.

The judges also asked multiple times how states and utilities were harmed by the order, noting that they had not made any claim that they were being forced to meet certain requirements. They also asked why the court should not wait until FERC challenged a state prohibiting a resource from accessing a wholesale market before it decided on the issue.

Garland asked Murphy if any state had laws or rules in place preventing distributed storage resources from selling into the wholesale market. Murphy conceded there were not. Garland also asked both her and FERC attorney Anand Viswanathan if the order usurped state authority to prevent storage resources from interconnecting at all; both said no.

Wilkins also asked if the order mandated that states facilitate storages' participation in the markets. Viswanathan said, "Absolutely not."

"The commission clarified throughout the rule that whatever authority states or retail regulators had before the rule to police matters like reliability and safety of the distribution system, none of those authorities are changed as a result of the rule," Viswanathan said.

The petitioners' arguments seemed to mirror those in Commissioner Bernard McNamee's dissent a year ago in Order 841-A, which clarified aspects of but ultimately upheld the original order. McNamee said he would have granted rehearing to reconsider not providing states the ability to opt out of the participation model for storage resources located behind the meter. (See *FERC Upholds Electric Storage Order*.)

But Viswanathan pointed out that "no one at the commission level made the argument that the commission simply does not have authority to regulate electric storage resources."

"What [the petitioners] have argued is that even if the commission has the authority over this practice, states still have to consent to it," he continued. "The problem with that ... is because of the limited nature of their challenge, either the commission has the authority over the practice, or it does not. ... There's no suggestion in the statute that the commission's Federal Power Act authority hinges on states approving" that authority.

## Analysis

"In our view, at least two of the three judges at the court appeared skeptical of claims brought by petitioners that FERC exceeded its statutory authority," ClearView Energy Partners said in a memo. "Therefore, we think the court may uphold the provision, either by rejecting petitioners' standing or by affirming the provision as within the commission's exclusive jurisdiction."

Even if the court agreed with the petitioners, ClearView said, "we do not expect a disruptive change to the opportunities for [storage] to participate in the wholesale markets and potentially earn new revenue streams" because their challenge was only to a narrow aspect.

"The court did not appear headed toward making a broad jurisdictional conclusion that would vacate 841," *tweeted* Jeff Dennis, general counsel for Advanced Energy Economy. "Seems like the court could either (1) dismiss for lack of standing, saying no state has shown precise harm to its regulation of distribution facilities or (2) find that 841 properly exercises FERC's authority over wholesale transactions by local storage resources, while leaving to a future case how this exercise of authority interacts with state actions to regulate safety and reliability of distribution facilities." ■

## FERC/Federal News

# FERC Extends Comment Deadline in Net Metering Dispute

*By Rich Heidorn Jr.*

FERC last week extended the deadline for comments in a high-stakes dispute over net metering until June 15 (*EL20-42*).

The New England Ratepayers Association (NERA) filed a *petition for declaratory order* on April 14 asking FERC to outlaw net metering for rooftop solar generation by ruling that the commission has exclusive federal jurisdiction over wholesale energy sales from generation sources located on the customer side of the retail meter.

The declaration would require such sales be priced under the Public Utility Regulatory Policies Act of 1978 or the Federal Power Act, which could require the customer to have a rate on file with FERC.

"In other words, the group seeks to end net metering as we know it," tweeted Ari Peskoe, director of the Electricity Law Initiative at the Harvard Law School Environmental and Energy Law Program.

FERC granted the 30-day extension in response to a request by the National Association of Regulatory Utility Commissioners, which cited the coronavirus pandemic and the potential impact of the commission's ruling in the case.

The association said states with full net metering programs treat the entire output of energy from an electricity consumer's generation source that is located on the same side of the retail meter as the consumer's load as subject to state jurisdiction.

"NARUC has not yet taken a formal position on this petition; however, many NARUC members have expressed serious concerns with the petition's timing, scope, jurisdictional implications and implementation challenges," it said in its *motion*.

The association, which had requested an extension until Aug. 12, was supported in its request by several state regulatory commissions, consumer advocates and other intervenors. NERA said it opposed any extension beyond 60 days.

*NERA* describes itself as a nonprofit advocacy group seeking to protect "families and businesses" from excessive utility rates.

The Energy and Policy Institute, however, *says* its "lobbying and regulatory advocacy often align with the interests of investor-owned utilities and the fossil fuel industry" and that it has close ties to New Hampshire Gov. Chris Sununu.

NERA's petition was filed by Steptoe & Johnson attorneys David B. Raskin and Richard L. Roberts and reiterates arguments that Raskin has been making for years. Raskin has represented the Edison Electric Institute in the past, but EEI has said it is not involved with the filing.

Dozens of stakeholders have filed to intervene in the FERC docket thus far, an indication of the stakes in the case. ■

FERC extended the deadline to June 15 for comments in a high-stakes dispute that could end net metering.

CAISO/West News

# CPUC, PG&E Agree to Record $1.9B in Penalties

## *Rechtschaffen Acknowledges 'Deeply Unsatisfying' Agreement Structure*

*By Hudson Sangree*

The California Public Utilities Commission unanimously approved a settlement Thursday with Pacific Gas and Electric that imposes record penalties of more than $1.9 billion on the bankrupt utility for safety and maintenance lapses that led to massive wildfires in 2017 and 2018.

But the unusual structure of the *agreement* left some dissatisfied — including the commissioner who authored it.

Commissioner Clifford Rechtschaffen | © *RTO Insider*

Instead of levying fines, the commission agreed to a package that denies PG&E recovery from ratepayers of approximately $1.82 billion in wildfire-related expenses, meaning shareholders will pay the costs. But half that amount probably would have been denied by the CPUC during ratemaking proceedings anyway because of PG&E's failure to operate its grid safely, said Commissioner Clifford Rechtschaffen, who led the effort to penalize PG&E.

The company also agreed to $114 million in system enhancements and corrective actions, to be paid by shareholders, and to return to ratepayers the hundreds of millions of dollars in tax savings it expects to recoup from operational expenses not covered by rate increases. The company will still benefit from tax savings from capital expenditures in keeping with Internal Revenue Service rules, Rechtschaffen said.

The only fine that's part of the agreement — $200 million that would otherwise go to the state's general fund — will be "permanently suspended," according to the terms of the settlement.

"I recognize that a permanent suspension of the fine is deeply unsatisfying to many," Rechtschaffen said. "Several intervenors strongly opposed this provision. I share this frustration. I think it's important to keep in mind, however, that this penalty action is only one of many aggressive steps that the commission's taking to hold PG&E accountable for its actions and to prevent future misconduct."

The commission has demanded enhanced oversight of PG&E and greater enforcement authority as part of its proposed approval of the utility's bankruptcy reorganization plan, which it intends to hear on May 21. (See *PG&E Deal with Gov. Allows for Utility's Sale*.)

Even so, Rechtschaffen said, "A fine is clearly appropriate here given the unprecedented scale and scope of harm from the wildfires that PG&E caused and because fines convey unique societal opprobrium."

The massive wildfires fires of 2017 and 2018 ignited by PG&E equipment included the Camp Fire, which leveled much of the town of Paradise and killed 85 residents, and the Northern California wine country fires of October 2017. A CPUC investigation found numerous lapses in equipment maintenance and vegetation management that were the basis for the penalties.

The fires were a "grim chapter in PG&E's history that had devastating consequences," Rechtschaffen said. "Our investigation found that PG&E's misconduct caused 15 of the wildfires resulting in unprecedented damage — over 100 people killed, 25,000 structures destroyed, hundreds of thousands of acres burned and the destruction of an entire community in Paradise."

The fires also led to bankruptcy, "an extraordinarily disruptive process for a company that provides essential utility services," he said.

PG&E said in a statement Thursday that it accepted the CPUC's decision and "will work to implement the shareholder-funded system enhancements and corrective actions called for in the settlement."

"We remain deeply sorry about the role our equipment had in tragic wildfires in recent years," the utility said.

### PG&E's Past Penalties

Thursday's settlement topped the CPUC's previous record of $1.6 billion in penalties imposed on PG&E in April 2015 for the San Bruno gas pipeline explosion in 2010, which killed eight and destroyed part of a suburban San Francisco neighborhood. PG&E was convicted in federal court of six felonies related to that disaster and remains on probation. (See *Judge Orders PG&E to Improve Line Inspections*.)

The settlement replaced an agreement reached in December between PG&E and the CPUC's Safety and Enforcement Division, among others, that would have penalized PG&E a total of $1.625 billion in disallowed costs and system enhancements, including $900 million in wildfire costs that the company may not have been entitled to recover from ratepayers in the first place, the commission said.

An administrative law judge recommended changes to that settlement in February, including $198 million in additional disallowed costs and the $200 million fine.

PG&E appealed, denying its potential liability for fires even as it was negotiating a guilty plea deal to 84 counts of involuntary manslaughter connected to the Camp Fire, Rechtschaffen said.

"The stridency of PG&E's appeal was highly unfortunate and deeply disappointing," he said, given the utility's "strongly professed recognition of the need to dramatically transform its culture, its approach to safety and its professed commitment to working collaboratively in the future with its regulators."

PG&E told the commission it would have to pay the $200 million fine out of the $13.5 billion trust for wildfire victims it plans to fund in its bankruptcy case. Otherwise the fine might upset the billions of dollars in financing agreements it needs to emerge from bankruptcy, PG&E contended.

The commission ultimately decided to adopt the judge's recommendations but to suspend the $200 million fine and allow PG&E to keep its tax write-offs for capital expenditures but not operational expenses. (The tax savings for all PG&E's disallowed wildfire costs is estimated to be about $500 million.)

PG&E's financial circumstances, and its need to emerge from bankruptcy by June 30 to participate in a state wildfire liability fund, made the concessions necessary, Rechtschaffen said.

The San Bruno fines included a $300 million state fine, a $400 million refund to gas customers and $850 million for gas system safety improvements.

PG&E was flush with cash then. Today, it is set to emerge from bankruptcy heavily indebted with its share price about $11 at the close of trading Thursday versus $52 when the CPUC levied the San Bruno fines.

"It is an extremely rare set of circumstances that justify a departure from our normal penalty rules as we've done here," Rechtschaffen said of the agreement. ■

## CAISO/West News

# EIM Board Hears COVID-19 Update

*By Hudson Sangree*

The coronavirus pandemic has curtailed demand for electricity and made it challenging for new entities to go live with the Western Energy Imbalance Market, but two recent activations went well despite the awkward timing, the EIM's Governing Body heard Wednesday.

Governing Body members were also briefed on EIM benefits and the impending departure of a member of the EIM's Body of State Regulators (BOSR).

On April 1, Arizona's Salt River Project (SRP) and Seattle City Light both went live with the EIM, joining the interstate real-time trading market's nine other active participants while many of their employees were working remotely.

"Since then, both entities have been operating smoothly in the market," said Petar Ristanovic, CAISO vice president of technology. In a slide, he wrote, "This was the smoothest EIM activation so far. Both entities were well prepared and their personnel trained so they were passing all hourly tests from the start."

The COVID-19 pandemic has kept most CAISO workers at home too, while control room staff have been isolated from others and separated by crews into two control rooms: one at the ISO's Folsom headquarters, and the other in its secondary control room in the nearby town of Lincoln, General Counsel Roger Collanton told Governing Body members. The ISO also set up a "virtual control room" in Folsom to use, for instance, when the main control room needs to be cleaned, Collanton said.

CAISO hasn't experienced any significant problems during the pandemic, he said. "We've seen no grid reliability issues, and we're not predicting any at this time."

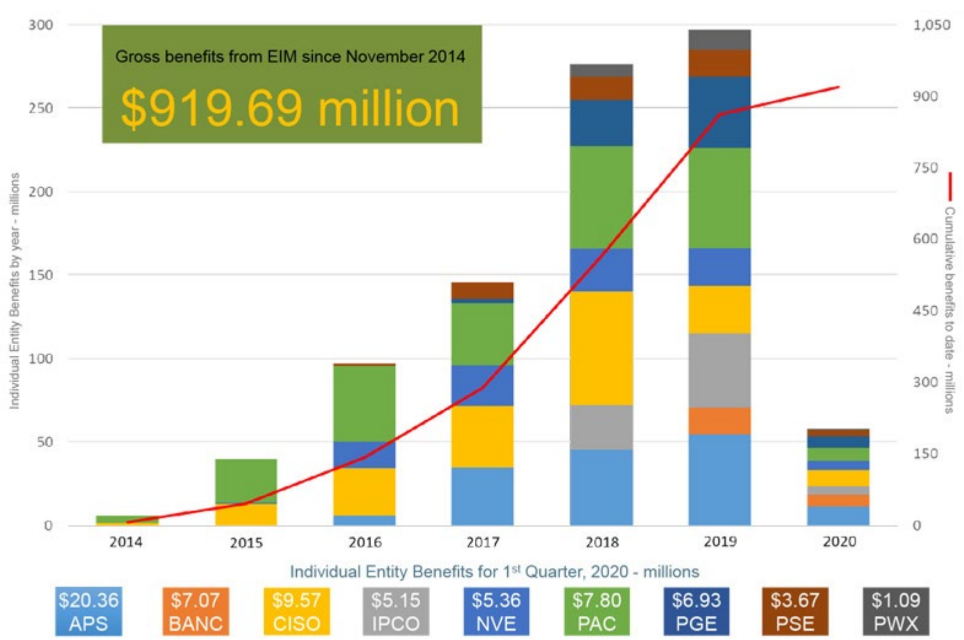
The ISO compared expected loads without California's stay-at-home order and actual loads with the order in place, Collanton said. Weekday loads were down by about 7.5% during peak-demand times and 5% during off-peak times. Weekend load reductions were less — 3% during peak demand and 1% off-peak.

Energy prices were down by 26% in the day-ahead market and 30% in the real-time market, he said.

### Benefits Heading Toward $1 Billion

Mark Rothleder, CAISO's vice president for market policy and performance, said the EIM saw "robust" member benefits of nearly $58 million during the first quarter of 2020, bringing its total benefits since its start in 2014 to almost $920 million.

SRP and Seattle City Light have already begun seeing benefits from joining the EIM, Rothleder and utility representatives said.




EIM benefits to date | *CAISO*

Salt River Project power lines traverse the desert near Tempe, Ariz. | *© RTO Insider*

The market is on course to accumulate $1 billion in benefits later this year, he said. The benefits often come from buying and selling excess renewable energy.

"We're seeing continued benefits and tracking well," Rothleder said. "In fact, we're probably tracking toward $1 billion in benefits since the start of the EIM — I'm estimating probably in the third quarter of this year."

### White Joining WECC

In a briefing from the EIM's BOSR, Chair Letha Tawney, with the Oregon Public Utility Commission, announced that Commissioner Jordan White, a familiar figure in Western energy circles, will be leaving the BOSR and resigning from the Utah Public Service Commission effective May 20.

White is joining the Western Electricity Coordinating Council, also headquartered in Salt Lake City, "so he's not going far, both literally and figuratively," she said. "But we will miss him. He is an engaged and effective member of the BOSR."

WECC announced May 1 that White will be filling a newly created role as vice president of strategic engagement and deputy general counsel. He has served in multiple roles in the EIM, both as chair of the BOSR just prior to Tawney's term and as a current member of the Governing Body's nominating committee.

"For those of you who've worked with him and know him personally, he's just very enjoyable and easy to work with and really brings a thoughtful perspective to the conversation," Tawney said. "We will wish him all the best in his new role."

Utah PSC Chair Thad LeVar will represent Utah on the BOSR after White's departure. Other BOSR members have started the process to replace White on the nominating committee. "We're hoping to have that done by May 20," she said. ■

# CAISO/West News

# Manmade Methane Could Replace Natural Gas, Backers say

## *Critics Call it Expensive Way for Gas Companies to Maintain Asset Values*

*By Hudson Sangree*

Calpine said it could operate its gas plants, such as the Yuba City Energy Center, with carbon-netural synthetic methane. | *Calpine*

Backers of manufactured methane say it could replace natural gas and help California meet its goal of 100% carbon neutrality by midcentury, but skeptics call it an unrealistic way gas companies are trying to hold onto the value of their plants and pipelines as demand decreases.

The issues were addressed last week during an industry webinar and separately in a *meeting* of the Western Energy Imbalance Market's Regional Issues Forum, both held May 5.

During the events, proponents said synthetic methane can be produced with carbon captured from the atmosphere using excess renewable power, making it "carbon neutral." They want California to recognize power-to-gas (PtG) as a non-polluting energy source under its renewables portfolio standard program, which requires all of the state's electricity to come from carbon-free resources by 2045.

California has renewable power in abundance, often with high curtailment rates. In April, for instance, CAISO *reported* a record of more than 318 GWh of solar and wind curtailment — the product of a shoulder month with high output and low demand coupled with reduced load because of the COVID-19 crisis.

"Any power system that has huge amounts of solar or wind in it, trying to push the 100% envelope, they will have as a necessary consequence huge amounts of overgeneration," said Joseph Ferrari, general manager of North American market development with Wärtsilä, a Finnish company that specializes in repurposing thermal generation infrastructure. "This is surplus electricity that just has to be dumped. There's really nowhere for it go.

Joseph Ferrari, Wärtsilä | *Wärtsilä North America*

"However, we can put it to use," Ferrari said during the Wärtsilä-sponsored webinar. "We can take that excess renewable energy to power electrolyzers, which take water and make hydrogen. We can take some of that excess renewable electricity and capture carbon directly from the air. And, finally, we can use more of that renewable electricity to power a methanizer process," which combines hydrogen and carbon to make methane.

"There's no fossil fuels involved, and there's no net increase in atmospheric carbon," he said. Existing gas plants can burn the fuel and current pipelines can carry it. It can be stored long-term or liquefied for transport.

A small percentage of hydrogen produced in the process can be added to methane without compromising generation or jeopardizing pipelines, the company and other proponents say.

### An Optimal Path?

In a Wärtsilä *white paper* Ferrari and three co-authors called PtG an "optimal path" for California to become carbon neutral by 2045 — the goal established by Senate Bill 100 — or even five years earlier. (See *Calif. Clean Energy Measure Goes to Governor*.)

The California Public Utilities Commission recently approved large increases in targets for renewable energy and storage, particularly batteries, to help meet the state's ambitious goals. (See *CPUC Approves Big Boost in Storage, Solar Targets*.)

But serious doubts remain about the ability of renewables and battery storage to meet California's energy needs. The state still relies heavily on gas generation to meet peak demand and to compensate during times of prolonged cloud cover and low wind, both common in winter.

CAISO has made it a top priority to fill an expected capacity shortfall starting this summer and worsening next year. Imports from outside the state are becoming limited with coal plant retirements and growing demand in other Western states. The shortfall is expected to occur primarily during peak evening demand in

# CAISO/West News

summer as solar goes offline. (See *CAISO, CPUC Warn of 'Reliability Emergency'*.)

Storage is key, but the current industry standard is four-hour batteries, not enough to cover prolonged shortages, Karl Meeusen, CAISO senior adviser for infrastructure and regulatory policy, said during the webinar.

"We need to make sure that that's not all we get," Meeusen said. "We need to have a diversity of storage duration —from four, six, eight and even longer hours — for availability of resources."

PtG advocates say synthesized methane can be stored for months and used for long run-times to cover seasonal shortfalls in summer and winter.

Meeusen stopped short of saying CAISO endorses synthetic methane, but he said all options need to be considered to maintain reliability and reach 100% carbon-neutral status.

Wärtsilä argues it has the answer in manmade methane.

"As fossil fuels are phased out, thermal assets [can be converted] to renewable fuel to form a large, distributed long-term energy storage system with durations of weeks, not hours, providing seasonal balancing and security of supply during extreme weather events," the company's white paper says. "Benefits of this approach include reaching RPS goals by 2040, five years ahead of schedule, and net-zero carbon by 2045."

Calpine, one of the major owners of natural gas generation in California, also argued for the introduction of renewable natural gas at the EIM's Regional Issues Forum.

"Gas capacity retention is part of a cost-effective resource mix to meet aggressive [greenhouse gas reduction] goals, the company said in its presentation. "Gas is needed even with a large storage buildout."

## Avoiding Stranded Assets

Skeptics, however, argue making methane is too costly and uses too much renewable power. They say owners of natural gas infrastructure just want to preserve the value of their assets as buildings are electrified and gas gets phased out.

"As fewer people use gas, it will become so expensive to run the gas system that people will flee," said Merrian Borgeson, a senior scientist with the Natural Resources Defense Council.

Owners of plants and pipelines are worried about seeing their assets stranded in the future, but instead of making methane, "our view is that gas companies are going to have to look at how to contract their infrastructure," Borgeson said.

In April, the California Energy Commission released a *report* by Energy and Environmental Economics (E3) and the University of California Irvine's Advanced Power and Energy Program that concluded PtG is problematic for widescale use. E3 also presented on the future of natural gas in the West at the RIF.

Merrian Borgeson, NRDC | *NRDC*

To meet California's climate goals, use of fossil fuels such as natural gas will need to decrease 80% by midcentury, it said. E3 said it hadn't found a solution that eliminates pipeline gas altogether, making some form of renewable gas a likely alternative. (Biomethane, produced from cow manure and other sources, is less expensive but limited by nature.)

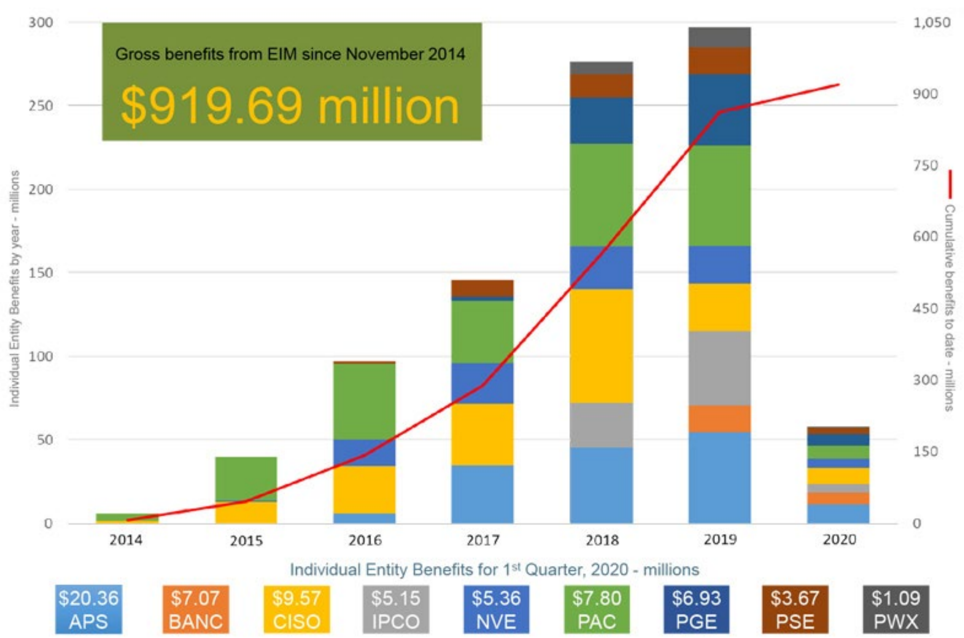
The study concluded that using only curtailed renewables could not synthesize enough methane to meet demand. Far more renewable electricity would be needed to produce enough manmade gas to replace natural gas at current demand levels, it said.

Another major problem is cost. E3 estimated that synthetic methane could run as high as $86/MMBtu in 2050 compared with $5/MMBtu for natural gas. Nearly 80% of all homes in California use natural gas, but faced with far higher gas bills, customers may decide that switching to electric furnaces and water heaters makes financial sense.

"Building electrification is likely to be a lower-cost, lower-risk long-term strategy compared to renewable natural gas," including manufactured methane, E3 said.

Addressing the situation now could help avoid having gas assets "not used or not useful" in the future, it said.

"By taking a long-term view of the state's climate goals and evaluating the role of the natural gas infrastructure in that future, this research allows the state to potentially avoid stranded assets in the gas system," the study said. ■




Excess renewables could be used to make methane and hydrogen for longer-term storage and generation. | *Wärtsilä*

ISO-NE News

# NEPOOL Participants Committee Briefs

## COVID-19 Precautions to Last All Summer

ISO-NE is planning to bring staff back to its Holyoke, Mass., headquarters in phases over the summer, CEO Gordon van Welie told the New England Power Pool Participants Committee on Thursday.

The RTO has had 95% of its workforce working remotely because of the COVID-19 pandemic since March 14, with remote deployment to continue through at least June 1, and is paying special attention to the health of crews for the two control centers, van Welie said.

ISO-NE has some questions about President Trump's May 1 executive *order* banning "any acquisition, importation, transfer or installation of any bulk power system electric equipment" controlled by or involving any foreign country or person, van Welie said. (See *Trump Declares BPS Supply Chain Emergency*.)

The order directs the energy secretary within 150 days to "publish rules or regulations implementing the authorities delegated."

In response to stakeholder questions, van Welie said nothing in the order has the RTO concerned, but he noted the need to live with uncertainty during the Energy Department's 150-day period for ruling on imported equipment that might fall under the ban of such critical energy infrastructure.

## Pandemic Load Factors

ISO-NE created a "backcast" model to provide a baseline of what loads should have been absent the pandemic, COO Vamsi Chadalavada said.

"The backcast is for March 1 to April 28, so that's about 59 days, and we've built a composite of what a load curve would look like by averaging every hour of those 59 days," Chadalavada said.

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

"It's interesting to see how those societal actions are reflected in a daily load profile ... a slower morning ramp, a later morning peak; mid-day loads are lower, evening peaks are lower, and the transitions to night loads are less steep," he said.

The RTO continued to observe approximately 3 to 5% lower loads in April, and there has been an approximately 6% reduction in average load when comparing this year to last, he said.

The pandemic accounts for up to 5% of the decreased load, but additional energy efficiency and PV installations likely make up a majority of the difference.

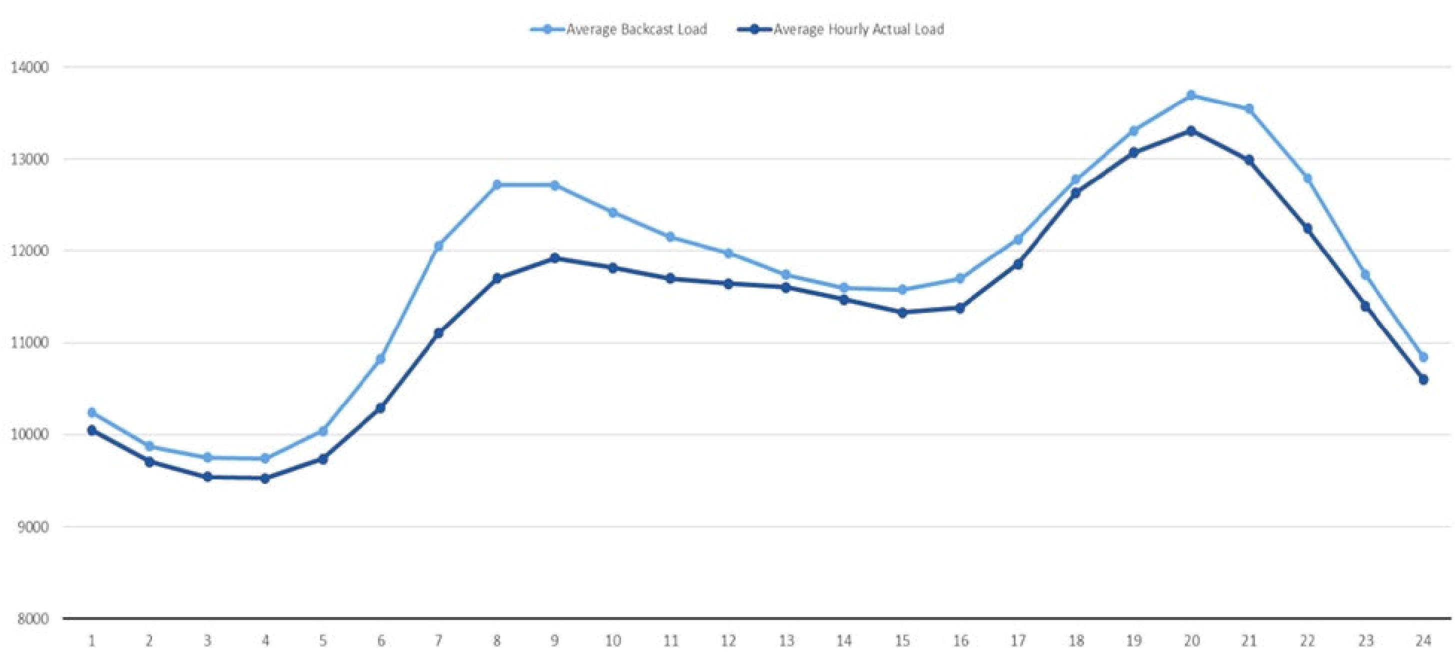
"Energy efficiency has been on a steady track in recent years, but PV has picked up lately, so it's not clear exactly how consistent this contribution to lower load is with historical trends," Chadalavada said.

## Faster Boston RFP

The RTO's competitive transmission solicitation for Boston garnered 36 proposals from eight qualified parties by the March 4 deadline. With the evaluation process moving faster than expected, stakeholders will see the early cut in July rather than August.

"I know there's been a lot of interest in the responses that we've received for the Boston [request for proposals], and in the volume, and the range of dollars, and the timelines," Chadalavada said.

The RTO is confident that some proposals in the phase one study process are going to be




Comparison of average hourly actual loads to backcast loads (March 1 through March 28) | *ISO-NE*

# ISO-NE News

available for New England ahead of June 1, 2024, the current retirement date for Mystic 8 and 9, he said.

"I think we had left you with an expectation that we will be sharing with all of you those proposals that move from phase one to phase two at the end of August," he said. "We are going to be able to do that in July, so it's at least going to be an acceleration of up to four weeks, but that doesn't mean we're stopping there. If we continue to make the progress that we are, we could maybe even be sooner in front of you with those proposals."

## Consent Agenda

Given the uncertainty surrounding the loosening of social restrictions in Massachusetts, the PC will hold no in-person summer meeting in June, said Chair Nancy Chafetz, of Customized Energy Solutions.

The PC on its consent agenda approved a revision to Operating Procedure 14 (*OP-14*) related to technical requirements for generators, demand response resources, asset-related demands and alternative technology regulation resources.

The PC also approved clean-up changes and enhancements to the RTO's billing policy, which were raised in conjunction with certain clean-up changes to the ISO-NE Financial Assurance Policy that are still under review by the NEPOOL Budget and Finance Subcommittee. The subcommittee discussed the changes during its March 26 and April 21 teleconferences, and no members objected to the changes.

## Litigation Report

NEPOOL Secretary David T. Doot delivered the monthly litigation report and highlighted several items, starting with the RTO's filing of its Energy Security Improvements (ESI) market design with FERC on April 15, for which the commission has set a May 15 comment deadline date (*ER20-1567*).

The second item was a technical conference on combined or hybrid resources to be held at FERC on July 23, focusing on a generation resource paired with storage.

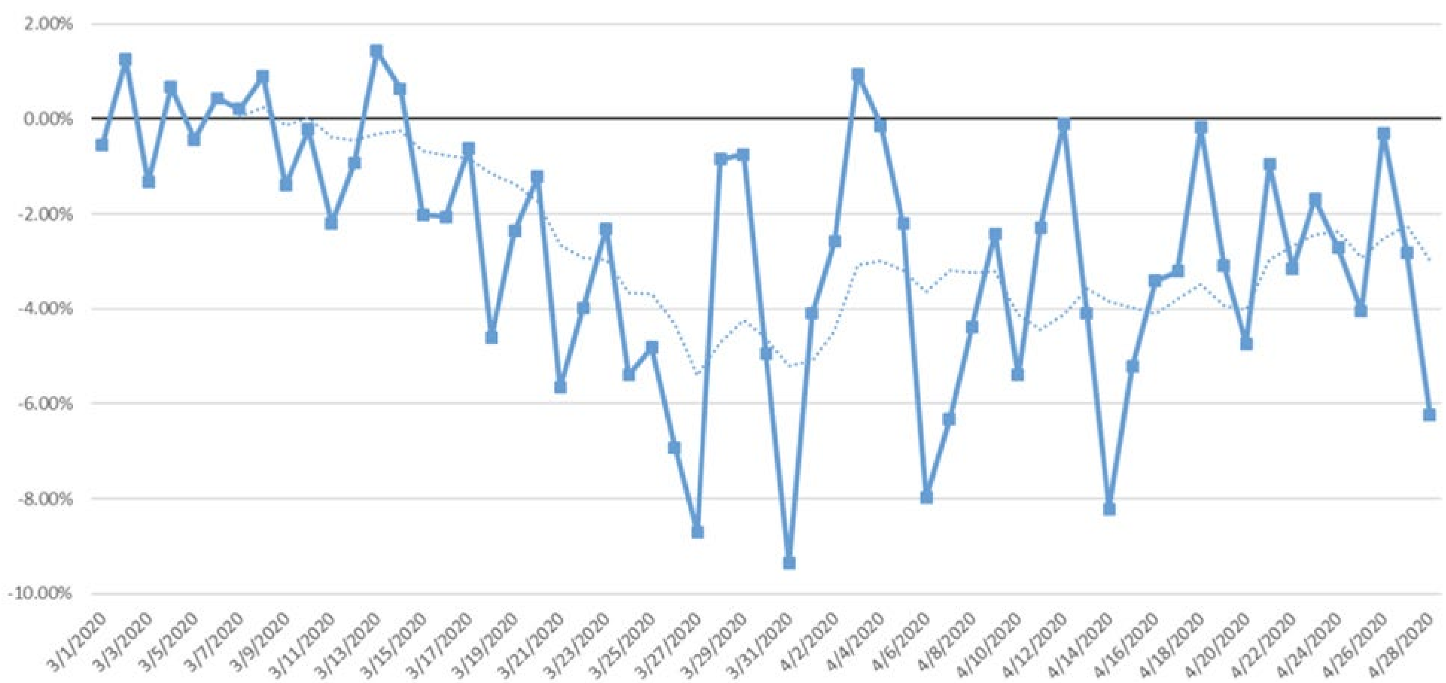
The third item concerned the New England Ratepayers Association (NERA) filing of a *petition for declaratory order* on April 14 asking FERC to outlaw net metering for rooftop solar generation.

NERA argues that the commission has exclusive federal jurisdiction over wholesale energy sales from generation sources located on the customer side of the retail meter. The commission on May 4 extended the deadline for comments in the dispute over net metering until June 15 (*EL20-42*). (See related story, *FERC Extends Deadline in Net Metering Dispute*.)

Another litigation item concerned a request that FERC convene a technical conference on the topic of carbon pricing, with the filing giving people until May 21 to submit comments.

The final item was ISO-NE's Inventoried Energy Program (Chapter 2B) proposal, for which a federal court granted FERC's motion to suspend briefing and for voluntary remand, directing parties to file status reports at 90-day intervals beginning July 20. (See "OKs Early EIP Sunset," *ISO-NE Sending 2 Energy Security Plans to FERC*.) ■

*— Michael Kuser*




Average hourly actual load deviations from backcast model | *ISO-NE*

## ISO-NE News

# Exelon Bid to Keep Mystic Units Running Provokes Outrage

*Continued from page 1*

"The filing preserves an additional option for Mystic 8 and 9 to provide unique fuel security and electric reliability benefits to the region following the cost-of-service period, if ISO-NE decides that it does not need Mystic 8 and 9 in the market for transmission security for at least one more year," Exelon Generation spokesman Mark Rodgers explained in response to questions from *RTO Insider*.

News of Exelon's change of heart provoked outrage among some stakeholders.

"Exelon is looking to keep the Mystic units in the market after holding the region hostage for millions of dollars in pursuit of short-term financial gain," Katie Dykes, commissioner of the Connecticut Department of Energy and Environmental Protection, told *RTO Insider*.

"Exelon's 2018 retirement announcement sought to exploit fuel security weaknesses in the region revealed by ISO New England's Operational Fuel-Security Analysis. Since then, the continuing failure of ISO-NE to timely address fuel security and recognize, rather than negate, state policies continues to expose our ratepayers to bald exercises of market power today," Dykes said.

Exelon's filing "appears to be a cynical ploy premised upon two inherent failings of ISO New England," said Greg Cunningham, director of Conservation Law Foundation's Clean Energy and Climate Change program.

"The first failing is to clear not much other than natural gas power plants in its Forward Capacity Auctions. And the other is the risk that it mismanages this [request for proposals] for transmission that will provide for an alternative to Mystic," he said, referring to ISO-NE's first-ever competitive transmission solicitation, issued in December.

**"Exelon is looking to keep the Mystic units in the market after holding the region hostage for millions of dollars in pursuit of short-term financial gain."**

— Katie Dykes, commissioner of the Connecticut Department of Energy and Environmental Protection

Everett High School engineering students visit the Mystic Generation Station in January 2020. | *Everett High School*

"This absurd result is entirely avoidable," Cunningham said. "If it manages this RFP well, ISO-NE can select projects that simultaneously address New England's clear public policy desire for clean resources, while avoiding a dinosaur of a plant like this coming back like a phoenix out of the ashes."

### No Gaming Allowed

"Under the ISO-NE Tariff, the rules are clear that the current Mystic generation must retire once the reliability needs are addressed," said Theodore Paradise, senior vice president of transmission strategy for Anbaric Development Partners. "Those rules were directed to be put in place by FERC to prevent gaming — seeking the higher of cost-of-service or market prices."

If the Mystic units try to lock in another high-priced contract triggered by their retirement announcement, that would "continue the injury to New England ratepayers already incurred by the astonishingly high annual cost-of-service agreement to keep both the plant and the LNG terminal," Paradise said.

"Mystic had its chance and made its decision for an economically challenged plant," he said. "Exelon has put in the binding retirement request, and those uneconomic, rate-

# ISO-NE News

inflating fossil units are going to be closed soon. Because of the lack of a gas supply situation, new LNG units at the site don't make sense economically at current energy and capacity prices."

## Uneconomical

Exelon two years ago said it would retire Mystic as uneconomical, given the plant's dependence on LNG that costs more than natural gas from pipelines.

The cost-of-service agreement for Units 8 and 9 and the Exelon-owned LNG terminal that supplies them is scheduled to expire in May 2024. The agreement pays Exelon an annual fixed revenue requirement of almost $219 million for capacity commitment period 2022/23 and nearly $187 million for 2023/24, subject to true-ups for fuel costs.

ISO-NE initially asked FERC to waive Tariff provisions to prevent the retirement because of the region's fuel-security reliability challenges in winter. FERC rejected the request, ordering the RTO to amend its Tariff — which then allowed cost-of-service agreements only to address local transmission security issues — to now allow such contracts for fuel security issues. The commission also ordered the RTO to develop market-based solutions to address fuel security, setting off a two-year effort that culminated with the RTO's filing of its Energy Security Improvements (ESI) market design on April 15. Exelon filed its interconnection request five days later.

## FCA 15

Exelon's mention of providing "fuel security" had some observers scratching their heads, considering the RTO's assertion at the New England Power Pool Reliability Committee meeting last month regarding FCA 15, the auction that will be held next year for capacity year 2024/25.

ISO-NE *presented* the RC with its initial inputs to the fuel security reliability review, which indicate that no resources that submitted a retirement delist bid for FCA 15 or were previously retained for fuel security will be retained for fuel security for the period. (See "FCA 15 Fuel Security Reliability Review," *NEPOOL Reliability Committee Briefs: April 22, 2020*.)

But maintaining interconnection access would allow Exelon to extend Mystic's stop-gap role if there were delays to either the planned transmission upgrades or the approval and implementation of ESI. ISO-NE asked FERC to approve ESI effective Nov. 1.

ISO-NE has kept Exelon's Mystic Generating Station operating under an expensive and controversial out-of-market contract for reliability reasons. | *Anbaric Development Partners*

**"If it manages this RFP well, ISO-NE can select projects that simultaneously address New England's clear public policy desire for clean resources, while avoiding a dinosaur of a plant like this coming back like a phoenix out of the ashes."**

— Greg Cunningham, director of Conservation Law Foundation's Clean Energy and Climate Change program

Exelon also would face an obstacle from the commission's requirement in its December 2018 order accepting the Mystic agreement that it include a "clawback" mechanism.

The order said that if Mystic re-entered the market after the agreement ends rather than retiring, Exelon would have to refund to the RTO "all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation" of Mystic during the agreement (*ER18-1639*). The commission said the clawback "will not apply if ISO-NE chooses to extend the agreement."

The commission disputed Mystic's contention that cost-of-service agreements used for fuel security purposes merit different clawback treatment than those for transmission. "We disagree. At the end of a cost-of-service agreement's term, the need for the unit to provide relief for a transmission constraint would be replaced by a transmission upgrade," the commission said.

"In this case, the need for cost-of-service treatment for Mystic will have been replaced by a market-based mechanism for fuel security," the commission said. "Under a market-based mechanism, if Mystic is not the most economic alternative to meet a fuel security need, then Mystic will not be selected to provide capacity and/or fuel security. The clawback mechanism helps place Mystic on similar footing with other resources that would not have benefited from a cost-of-service agreement in the new market-based mechanism."

Under ISO-NE's Tariff, to qualify as a "new" capacity resource, Mystic would have to add 40 MW of capacity over its last summer qualified capacity number or invest at least "$200/kW of the whole resource's summer qualified capacity after repowering … (in base year 2008 dollars)."

## RFP

ISO-NE received 36 proposals in response to its December 2019 solicitation to address reliability concerns over Mystic's retirement, specifically transmission facility overloads under peak load conditions in the Boston area and system restoration concerns with the underground cable system in the area.

# ISO-NE News

The RTO said the proposals ranged from $49 million to $745 million with in-service dates from mid-2023 to 2026. It said it would not disclose proposal details for 175 calendar days (until Aug. 26), after verifying details in the proposals. It expects to make a final selection in summer 2021. (See *ISO-NE Planning Advisory Committee: March 18, 2020*.)

The only proposal made public so far is one from Anbaric, which announced details for the 900- to 1,200-MW Mystic Reliability Wind Link *project* to bring offshore wind energy interconnecting in southeastern New England to Boston. It includes empty cable conduits for an additional 1,200 MW from offshore wind farms.

Massachusetts Department of Public Utilities Chair Matthew Nelson seemed unconcerned that Mystic might not retire as scheduled, saying the department "is encouraged by the ISO-NE competitive process for transmission and continues to be focused on ensuring Massachusetts ratepayers are provided with the most reliable service at the lowest possible cost."

## ESI

The ESI market design will allow ISO-NE to procure energy call options for three new day-ahead ancillary service products to improve the region's energy security, particularly in winter when natural gas shortages can leave generators without fuel. Option awards will be co-optimized with all energy supply offers and demand bids in the day-ahead market. (See *ISO-NE Sending 2 Energy Security Plans to FERC*.)

Based on a related proceeding at FERC in March, Exelon apparently believes that it is now free to pursue a separate cost-of-service agreement based on "transmission security" rather than fuel security.

While all six New England states pay for the cost of a fuel security cost-of-service agreement, the Tariff says the cost of a transmission security agreement for Mystic would be paid by the Northeast Massachusetts capacity zone, which includes Boston.

FERC in March rejected Tariff revisions filed jointly by the RTO and the New England Power Pool to clarify that resources retained for fuel security reasons will not be retained for other reasons once the fuel security retention period ends (*ER20-89*). (See *FERC Rejects ISO-NE Fuel Security Tariff Revisions*.)

Exelon in that proceeding argued that the proposal "unduly discriminates" against fuel security resources in general and the Mystic units in particular. The company contended that "the proposal results in different treatment for transmission security resources based on whether the resource has previously provided fuel security service, despite the fact that transmission security and fuel security resources are similarly situated for purposes of retirement."

The RTO's desire to develop a long-term market-based fuel security solution and competitively develop transmission solutions for the Boston area do not constitute substantial evidence that it is just and reasonable to eliminate a reliability safeguard, Exelon said.

In rejecting the revisions, the commission found that "instead of retaining such a resource for transmission security (as it would any other resource that was not previously retained for fuel security), ISO-NE would need to address this issue through either real-time operating procedures, such as shedding load, or through the use of a gap RFP solicitation." ■

**"Under the ISO-NE Tariff, the rules are clear that the current Mystic generation must retire once the reliability needs are addressed. Those rules were directed to be put in place by FERC to prevent gaming — seeking the higher of cost-of-service or market prices."**

—Theodore Paradise, senior vice president of transmission strategy for Anbaric Development Partners


Anbaric's proposed Mystic Reliability Wind Link would bury transmission cables underground and under the seabed from Plymouth, Mass., to Everett, Mass., site of Exelon's Mystic Generating Station. | *Anbaric Development Partners*

# Stakeholders Question High Mich. Capacity Prices

By Amanda Durish Cook

Stakeholders are asking if MISO's new long-term generation outage policy played a role in driving up Michigan capacity prices in this year's Planning Resource Auction.

While nearly all MISO local zones cleared under $7/MW-day in last month's 2020/21 PRA, Lower Michigan's Zone 7 cleared at the $257.53/MW-day cost of new entry price — 10 times the capacity price paid in the last planning year. (See *Michigan Prices Soar in 8th MISO Capacity Auction*.)

During a Resource Adequacy Subcommittee teleconference Wednesday, MISO Manager of Capacity Market Administration Eric Thoms told stakeholders that Zone 7 came up short of capacity to meet its local clearing requirement and had to import capacity, activating the CONE price.

Stakeholders asked if the Independent Market Monitor examined whether MISO's new long-term outage rules might have been used as a façade by some Zone 7 resources to physically withhold capacity and drive up prices. The new rule stipulates that planning resources cannot offer into the auction if they plan to be on outage for longer than 90 days of the first 120 days of the planning year. MISO deems the first four, warm months of the planning year as the time when capacity availability is most critical. The RTO's 2020/21 planning year begins June 1.

IMM staffer Michael Chiasson said the Monitor scrutinized long-term outages to make sure they were justified.

"We don't want people to have outages in there that give them an excuse to not participate," Chiasson said. "It's kind of like a road with two ditches: Don't participate if you shouldn't, and participate if you should."

Chiasson also said that some Zone 7 resources didn't offer all the capacity they had, but the unoffered supply was below the Monitor's conduct threshold of 50 MW per affiliated companies per zone. MISO's 2017 rule applies a 50-MW physical withholding *threshold* to affiliated market participants collectively, rather than individually to each affiliated company.

Last year, the Monitor had to enforce market mitigation for economic withholding in Zone 7, resulting in a 1 cent/MW-day reduction in the Lower Peninsula. Zone 7 also cleared higher than all other zones last year, at $24.30/MW-day compared to $2.99/MW-day everywhere else.

Thoms said MISO will discuss how it approached its loss-of-load sensitivity analysis for Zone 7 at the June 10 RASC meeting. He said MISO would also investigate whether Zone 7 would have come up short in the last planning year had the long-term outage rule been in place at the time.

MISO's 2020 Transmission Expansion Plan contains a special *study* into the increasingly tight capacity import and export limits (CILs/CELs) in Zone 7. The Michigan Public Service Commission requested the study, which will help the state "better understand the effects" of increasing either the CIL or CEL for Zone 7, according to MISO. (See *Northern Focus for MTEP 20*.)

Meanwhile, MISO says it wants to be more transparent in how it develops its loss-of-load expectation study.

"This is something we're struggling with. … We're trying to figure out how to get more stakeholder engagement earlier and up front. We want to make sure this process is meaningful," RASC Chair Chris Plante said.

Customized Energy Solutions' Ted Kuhn said the problem is that MISO makes a "fluffy," introductory presentation one month, then comes back with LOLE study results in the next month.

"We never saw how this was being developed in the first place. … So something needs to change in how they're developing their work products," Kuhn said. ■

Eric Thoms, MISO | © *RTO Insider*

## MISO News

# MISO Plugs SATOA Plan at FERC Conference

*By Amanda Durish Cook*


Jeff Webb, MISO | © *RTO Insider*

MISO defended its first storage-as-transmission proposal before FERC staff last week, maintaining that the plan is a good interim measure while the RTO designs a more permanent approach.

The contentious proposal was the focus of a May 4 technical conference to allow FERC to weigh the merits of the plan. (See *MISO SATOA Proposal Set for Technical Conference*.) Many MISO stakeholders have complained that the proposed ruleset would give incumbent transmission owners an effective monopoly on storage assets functioning as transmission, harming competition. (See *MISO SATOA Proposal Faces Opposition*.)

The plan limits storage-as-transmission assets to transmission-only functions operated by MISO-defined TOs. As such, a new category of storage-as-transmission-only assets (SATOA) would be barred from simultaneous participation in MISO's energy markets — for now. The RTO has contended that its plan will avoid introducing complexities around cost recovery, particularly the thorny issue of how to compensate non-TOs for providing transmission services.

But FERC in March ruled that MISO's bid to include storage options in its annual transmission planning might be "unjust, unreasonable, unduly discriminatory or preferential," suspending the provisions until Aug. 11 and calling for the conference (*ER20-588*).

FERC Chairman Neil Chatterjee opened the commission's first-ever virtual conference saying that he would pay special attention to the subject matter.


Brian Pedersen, MISO | © *RTO Insider*

"I believe electric storage is a transformative technology that will be crucial to the grid of the future," Chatterjee told listeners.

MISO Senior Manager of Competitive Transmission Administration Brian Pedersen called the proposal a "fundamental first step" in unlocking the full potential of energy storage facilities and said it represents a year-and-a-half of the RTO's efforts in considering stakeholders' opinions.

Pedersen acknowledged that some stakeholders advocated for storage to be allowed to simultaneously function as both transmission and energy market assets but said designing rules for dual-mode participation, a project selection process and a cost recovery mechanism for non-TOs would be too complex to implement right away.

"To do so would delay the issue by months, even years," Pedersen said.

MISO officials said their approach to approving SATOA projects will factor in the length of time to get a resource operational versus traditional wires solutions, its effectiveness in resolving contingencies, availability and reaction times, what right-of-way space is necessary and the resource's performance degradation over time. State-of-charge responsibilities will rest with the storage owner, though MISO could direct that a device be fully charged at certain times.

Pedersen said the RTO will also consider how the connection of a SATOA will impact generation awaiting interconnection in the queue.

Director of Planning Jeff Webb said MISO would not select SATOA devices in congested locations where several generation projects are vying for interconnection to avoid disrupting the queue. Stakeholders have voiced concern that SATOA projects would supersede planned generation projects by taking points of interconnection.

FERC staff said it wasn't evident where the RTO's proposal detailed such a no-harm process.

"I think it deserves some business practice manuals, but that's the idea," Webb said.

FERC staff also asked whether MISO expects SATOA to have the same impact on the generation interconnection queue as new traditional transmission projects.

"That's hard to put your finger on. … There's a number of possibilities," Webb said, adding that SATOA will be able to charge to offload lines as well.

Storage solutions that function more like energy resources will not be selected through the annual MISO Transmission Expansion Plan (MTEP); instead, they will have to go through the interconnection queue, Webb said. MISO expects that the more complicated a transmission issue is, the less likely a storage facility will be able to solve it.

Webb said the RTO envisions storage would most often resolve "N-1, steady-state issues." A battery is less likely to "be at the right state of charge" and ready for dispatch to solve rapidly emerging second contingencies. But MISO executives also said SATOAs could solve transmission issues complex enough that the

# MISO News

RTO will need functional control of them.

"We're at the front end of this; we haven't seen all transmission problems that storage could solve," Webb added.

Pedersen said that, "all things being equal," MISO would lean toward traditional wires solutions in the event of a tie because wires are historically better at mitigating stacked contingencies and currently have longer lifespans.

The RTO's MTEP report will include the rationale for SATOAs that are selected, Pedersen said. Stakeholders can address additional questions about SATOA selection to MISO's subregional planning meetings throughout the year. SATOA will be subject to the same planning studies required of other transmission projects.

In response to a FERC question about whether SATOA energy injections would impact MISO's market-based activity, Webb said even conventional wires have some impact on the energy market.

"Anytime you change the topology of the grid … yes, there will be some impact," he said. "We think these situations are going to be minimal."

"It isn't a completely new concept for transmission to affect markets," Webb added.

MISO will develop operational guides with SATOA owners to ensure energy market impacts are minimized. He said SATOAs, non-transmission alternatives (NTAs) and traditional transmission projects all involve assurances to the RTO that projects will be completed, either through the MISO Transmission Owner Agreement or through individual interconnection agreements.

## Not Comparable

DTE Energy's Nick Griffin, whose company is a vocal opponent of MISO's proposal, asked why the RTO couldn't simply ask market-based storage facilities to keep some charge reserved for transmission issues.

Webb said that discussion is best reserved for MISO's planned discussions on dual-mode participation in 2021.

Griffin said DTE continues to believe that the RTO's proposal creates unduly discriminatory preference for TOs over generation owners with comparable projects.

FERC staff said they were aware of the allegations of discriminatory treatment surrounding MISO's proposal. They asked why the RTO's proposal was necessary, as it already has rules in place for selecting NTAs in place of transmission projects. NTAs must first clear MISO's roughly three-year generation interconnection queue before being placed in-service, while SATOAs need only be selected in the annual MTEP process for grid connection.

"If someone came and invoked undue preference, I'm not sure how we could address it besides give them the same deal," FERC staffer Rahim Amerkhail said.

"What we're trying to do here is not reclassify assets and redefine revenue streams but see how we can extract extra value from storage with these specific boundaries around what is generation and transmission," Webb said.

Clean Grid Alliance's Rhonda Peters said she took issue with the fact that SATOAs and NTAs will be subject to different study processes that can include diverging assumptions.

Webb responded that issues stemming from the different assumptions in generator interconnection studies and MTEP studies are not unique to SATOA projects. MISO is currently working with stakeholders to better synch the two. (See *MISO Begins Bid to Merge Tx, Queue Planning*.)

"I think it's really up for debate that the studies produce comparable results," Peters said.

Responding to another FERC staff question, Webb said MISO has not contemplated a process for transitioning a SATOA to an energy market asset when it is no longer needed as a transmission resource because of load or grid changes.

"That's something we have not bitten off in this filing," he said. ■

# MISO Leans Toward Seasonal RA

By Amanda Durish Cook

MISO says it is contemplating creating a seasonal design for its resource adequacy construct to manage potential reliability risks outside of the summer months.

"Patterns of risk may already be shifting out of peak load periods," Jessica Harrison, MISO director of research and development, told stakeholders during a Resource Adequacy Subcommittee teleconference Wednesday.

MISO has said its current annual resource adequacy construct and yearly loss-of-load expectation (LOLE) study may not be enough to address the reliability risks it encounters throughout the planning year.

An evolving fleet is nudging MISO's loss-of-load risk to periods outside of the typical summer peak, the RTO said. It is increasingly encountering resources that have different capabilities depending on the season and a "notable increase in aging baseload units operating sub-annually."

Harrison said MISO's reliability risk also "increases noticeably in winter when accounting for seasonal patterns in outages." She said the RTO's analyses of 2018 data have found a "moderate" risk of loss of load in all of January and some days in February, in addition to the expected moderate to severe reliability risks in the summer months.

Harrison characterized the analyses as "initial" to determine whether "something other than an annual forced outage rate makes sense" in MISO's LOLE study.

WPPI Energy's Steve Leovy pressed MISO to provide a "comprehensive" loss-of-load analysis that proves a clear shift to risks outside of summer.

"The history of maximum generation events isn't satisfactory. … MISO still hasn't shown an analysis that shows a resource adequacy risk in non-summer seasons," Leovy said. "I believe, in MISO's mind, they've already decided there's a risk. We shouldn't be at a place yet where MISO proposes seasonal changes. And I'm very afraid that we're already there, and we're going to skip over a demonstration."

Harrison said MISO's initial studies don't yet provide a full justification for seasonality.

"However, we are starting to see some indicators," Harrison said, adding that stakeholders should expect more MISO analyses on seasonality in resource adequacy.

"We're trying to understand needs before we move into design," she said, adding that MISO also "has to keep the pace up" in reacting to industry change.

Customized Energy Solutions' David Sapper urged MISO to conduct its future analyses by giving some consideration to low load levels brought on by an economic depression triggered by COVID-19.

MISO's second annual Forward Report, released in March, concluded that it must soon break out its annual LOLE study and Planning Resource Auction by season. (See *MISO Forward Report Stresses Near-term Change*.) The RTO said it could begin making filings to move toward a seasonal resource adequacy construct late this year and in 2021.

Johannes Pfeifenberger, a principal of The Brattle Group, said multiple organized markets have turned to a seasonal resource adequacy construct, with NYISO's two-season capacity market implemented the earliest in 1999. CAISO enforced monthly resource adequacy requirements for load-serving entities starting in 2004.

He said PJM in 2016 attempted to implement a year-round availability requirement while maintaining a summer reliability benchmark.

"That's not really working well for some seasonal resources," Pfeifenberger said of PJM's treatment. "They've left it up to seasonal resources to figure out how they're going to provide a year-round product."

Pfeifenberger said even non-market entities like Southern Co. and the Tennessee Valley Authority have "migrated somewhat to winter reserve markets." He said Alabama Power shifted to winter peaking in 2011 and now uses a 25% winter planning reserve margin compared to a 15% summer planning reserve margin. ■

DTE Energy's Polaris Wind park | *DTE Energy*

## MISO News

# MISO Delays New LMR Accreditation Launch

*By Amanda Durish Cook*

MISO's plan to crop some load-modifying resources' capacity credits remains unpopular with many stakeholders, prompting the RTO to postpone the new accreditation for a year.

Scott Wright, Resource Adequacy Subcommittee liaison, announced during a conference call Wednesday that the new accreditation approach will be pushed to the 2022/23 planning year beginning June 2022.

MISO Director of Resource Adequacy Coordination Zakaria Joundi said the RTO would still file with FERC for the changes this month, adjusting the effective date for 2022 instead of 2021.

"So next year, there will be no change; the current methodologies will stay the same. But starting [the year after], you'll begin to see some changes," Joundi told stakeholders.

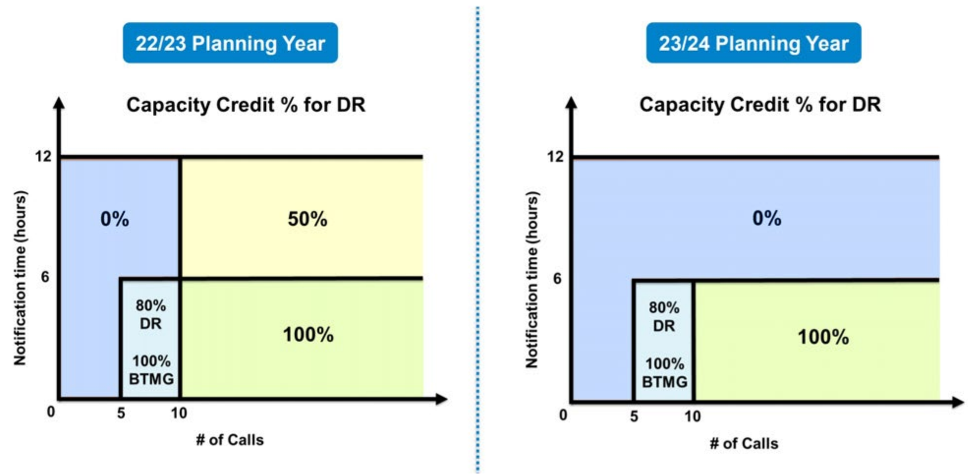
MISO plans to set an LMR's capacity accreditation at either an average of its actual availability over a three-year period or its tested availability, whichever is less. LMRs that can respond more often and with shorter lead times will receive a larger capacity credit; those that can respond in six hours or less to 10 or more calls per year will receive a full capacity credit.

Last month, MISO eased its proposal to eliminate the capacity credits of LMRs with lead times greater than six hours, offering them a 50% capacity credit for two years if they can respond to at least 10 calls in a year. The RTO maintains that LMRs needing more than six hours' notice don't help mitigate emergency conditions. (See *MISO Offers Concession on LMR Capacity Credit Plan*.)

Beginning in the 2023/24 planning year, MISO will no longer offer any capacity credits for LMRs with six hours or greater lead times or that cannot respond to at least five calls in a planning year, Joundi said.

In spite of last month's revision, stakeholders overwhelmingly *voted* to postpone the new accreditation via an email ballot that closed April 15.

Energy counsel Jim Dauphinais, on behalf of the Louisiana Energy Users Group, said a 2021/22 planning year effective date "does not provide sufficient time for action to be taken to avoid a potentially large unnecessary exit of capacity from the MISO market."




MISO LMR capacity accreditation plan | *MISO*

Gabel Associates' Travis Stewart asked if MISO expects LMR owners to use the extra year to make modifications to be more available or simply expects them to collect another year's worth of capacity credit.

"If MISO can't depend on them, then the accreditation should show up immediately," Stewart said.

Joundi said the additional year will allow load-serving entities to reopen LMR contract provisions to either amend availability times or revise the number of calls to which resources are willing to respond.

"It's more about administration … and less about technology," he said.

MISO said it "encourages stakeholders that can obtain reductions in notification times or increase call limits to do so prior to the 2022/23 planning year," especially for LMRs in local resource zones that rely more heavily on load modification.

Some stakeholders agreed, saying the more immediate change would cause some demand response to abandon the MISO capacity market.

WEC Energy Group's Chris Plante asked MISO to first perform loss-of-load-expectation analyses to measure the benefit of a reduced LMR capacity credit.

"We believe that LMRs with lead times greater than six hours, but less than 12 hours, provide some reliability value and should receive some amount of credit after 2023," Plante said in comments to the RTO.

Other stakeholders again asked MISO to wait and see how new LMR rules work out before proposing a new LMR capacity accreditation. FERC early last year allowed MISO to require LMRs to offer capacity in accordance with a seasonal availability report provided to the RTO and commit to deploying based on a notification time no longer than 12 hours. (See *MISO LMR Capacity Rules Get FERC Approval*.)

"MISO should allow the impacts of the changes from 2019 to be studied before making these additional changes. Furthermore, any additional changes to LMRs should be done as part of the larger resource accreditation effort to be undertaken by MISO and not in this piecemeal, one-off, incremental approach," Vectren's Michelle Quinn said.

MISO this year will pursue a *rethink* of all other resource accreditation, saying its current approach results in "inequitable treatment among resource types providing different levels of reliability contribution."

"We definitely want to show stakeholders what's clearing in the Planning Resource Auction versus what is showing up in the MISO Communications System. I think that'll give transparency into what's available to our operators when conditions may be tight," planning adviser Davey Lopez said. Once cleared in the capacity auction, MISO's planning resources use the Communications System to convey their availability to the grid operator. ■

# Test Phase Approaches for MISO Market Platform

*By Amanda Durish Cook*

MISO is ready to begin testing some of the capabilities of its new market platform as the effort to develop the system enters its fourth year, stakeholders learned last week.

"It's really an exciting time for the program because we're pivoting from foundational work to delivery," MISO Senior IT Director Curtis Reister told stakeholders on a Market Subcommittee conference call Thursday.

Reister said members' IT departments will soon begin testing MISO's new market user interface software in a customer test environment.

MISO expects it will begin transitioning to the new interface by the third quarter of 2021, running the system in parallel to the old platform for several months to allow members to phase in the change before the old interface is officially retired in early 2022, Reister said.

The RTO reports that 291 companies currently use its market user interface.

"It's not like every member has to transition on the same day. This allows members to attempt to transition … and go back and forth as many times as needed," Reister said.

Because of vendor delays, MISO now says it's unsure if it can meet a self-imposed June deadline to demonstrate the operation of its private cloud using non-Critical Infrastructure Protection data. The new private cloud will house the modular platform, replacing the current server-based platform.

The RTO plans to migrate data to its new private cloud for testing and import modeling information to its one-shop model manager this year. (See "Private Cloud Prepped for New Market Platform," *MISO Board of Directors Briefs: Dec. 12, 2019*.)

By the end of the year, MISO will have uploaded its operations data in the model manager, which is scheduled to go live next year, Reister said.

"Modeling is interwoven in a lot of MISO processes," Reister said of the importance of a singular repository for the RTO's many planning models. MISO currently relies on several different means to collect and validate grid information for modeling.

MISO said the contract and delivery date of work on its new day-ahead market clearing engine is currently under negotiations. Its goal is to have the existing platform and a version of the new platform running in parallel for testing purposes in 2021, paving the way for the eventual retirement of the old platform. The RTO hopes to have the new clearing engine in production in the third quarter of 2022.

MISO executives have said that the monolithic nature of the current market platform is a major limiting factor in adapting its market to accommodate new products that seek to incentivize availability of the RTO's shifting resource mix.

"2020 is the fourth year of the program, and it represents a turn in focus of the work," Vice President of Market System Enhancements Todd Ramey said during MISO Board Week in March. "Whereas the first three years of the program were primarily focused on extending the life of the legacy platform … this year we're really making the switch to completing major projects and bringing some of this online." ■

## MISO News

# Constellation to Pay AEP $253K in Tx Fee Dispute

Exelon's Constellation NewEnergy retail unit will pay American Electric Power $252,701 to settle AEP's complaint over *MISO's* failure to collect transmission charges from a defunct load-serving entity more than a decade ago.


AEP's Columbus, Ohio, headquarters

The settlement, approved by FERC on Friday, addresses charges billed to Nicor Energy (*EL18-7-001, ER20-207*). Constellation *purchased* most of Nicor's competitive energy supply contracts for 8,000 commercial and industrial gas and electric customers in Michigan, Illinois and Indiana in 2003.

In a 2017 complaint, AEP claimed that MISO owed more than $4.8 million to its PJM transmission affiliates after MISO failed to bill seams-related surcharges to Nicor and energy providers Engage Energy America and The New Power Co., all of which shuttered before December 2004, when MISO created the charges. (See *AEP Seeks $4.8M from MISO in Past Lost Revenues Complaint*.)

AEP sought the money through the Seams Elimination Charge/Cost Adjustments/Assignments (SECA), a non-bypassable surcharge in MISO's Tariff intended to recover lost revenues for a 16-month transition period during the elimination of through-and-out rates in late 2004 in the MISO and PJM regions.

AEP said its withdrawal of its complaint in docket EL18-7 eliminates the need for the commission to act on pending rehearing requests by itself and MISO.

The settlement said the payment by Constellation is "a complete and final settlement" of Exelon's SECA obligations to AEP but that AEP's withdrawal of its complaint is without prejudice to its right to initiate a future proceeding seeking recovery of SECA payments from other parties.

AEP did not respond to a request for comment on whether it will pursue claims over Engage and New Power. Engage went out of business in 2004, and New Power was liquidated in bankruptcy in 2003. ■

*— Rich Heidorn Jr.*

PJM News

# PJM, IMM Present MOPR Rules for State Procurements

## *Appeals Assigned to 7th Circuit*

*By Michael Yoder*

PJM and its Independent Market Monitor on Wednesday shared with stakeholders their proposals for responding to FERC's April 16 directive that state default service auctions be considered state subsidies and subject to the minimum offer price rule (MOPR).

The straw proposals are attempting to address *Paragraph 386* of FERC's rehearing order, which said that state procurement auctions are a form of a state subsidy because they provide a payment or other financial benefit to capacity resources that are part of a state-sponsored or state-mandated process.

PJM attorney Chen Lu presented the RTO's *"potential compliance approach"* during a special session of the Market Implementation Committee on Wednesday.

The commission on April 16 rejected rehearing of its June 2018 order declaring PJM's capacity market unjust and unreasonable (*EL16-49-001*, *et al.*) and virtually all of its December 2019 ruling spelling out the expanded MOPR while providing clarification on several points (*EL16-49-002*, *et al.*). PJM presented its initial response to the orders at the April 30 Markets and Reliability Committee meeting. (See *PJM Outlines Revised MOPR Compliance Filing*.)

Opponents of the expanded MOPR wasted no time in petitioning the 7th Circuit Court of Appeals and the D.C. Circuit Court of Appeals to review the orders. (See *Stakeholders Appeal Expansion of PJM MOPR*.) On May 5, the U.S. Judicial Panel on Multidistrict Litigation consolidated the five petitions and assigned the case to the 7th Circuit in Chicago (Case *07/1:20-ca-01645*).

PJM Monitor Joe Bowring | © *RTO Insider*

Chen Lu, PJM | © *RTO Insider*

While the appeals are pending, PJM is required to make a new compliance filing by June 1.

To comply with FERC's directive, Lu said PJM plans to amend its March compliance filing by removing state default procurements as an exception from the definition of a state subsidy.

"We recognize there are several implementation challenges with this rule given that state auctions are generally brought after PJM's capacity auctions, and also the fact that the entities that bid in state procurement auctions do not necessarily participate in PJM's capacity market," Lu said. Revenues from state procurements may not be traceable to specific capacity resources, he added.

### PJM Straw Proposal Approach

Lu said the proposal attempts to comply with the rehearing order while preserving "normal commercial activity" associated with the state procurements.

PJM's proposal includes default service auctions in the definition of a state subsidy but excludes certain voluntary bilateral transactions from the definition where there's no clear linkage between the revenues from a state default procurement auction and a capacity resource.

Lu said any capacity resource that has a clear link to revenue from a state default procurement auction would be subject to the MOPR under the proposal. Included would be:

- a capacity resource that directly clears or intends to clear in a state default procurement auction;
- any state-directed, long-term bilateral transaction between a default retail service provider and an owner of the capacity resource; and
- long-term transactions between a default retail service provider and an "affiliated owner" of the capacity resource in which the transaction is unit-specific or "not at prevailing market rates."

Chen also laid out the types of transactions that would not be triggered by the MOPR:

- Transactions of one year or less between a default retail service provider and the owner of the capacity resource. These transactions are not designed to support the development, construction or operation of a resource.
- Long-term transactions between a default retail service provider and an "unaffiliated owner" of the capacity resource so long as the transaction is not directed by a state.
- Long-term transactions between a default

# PJM News

retail service provider and an "affiliated owner" of the capacity resource where the transaction is not unit-specific, is at prevailing market rates and is not directed by a state.

Sam Randazzo, chairman of the Public Utilities Commission of Ohio, asked Lu how the "prevailing market rate" would be calculated if a default auction is for an unspecified quantity and an unspecified time.

Lu said prevailing market rates could be demonstrated by showing the price was consistent with either the generally available price to all buyers or other competitive supply bids at the time of the auction. Lu said PJM recognizes state auctions typically happen after the capacity auctions have occurred, so auction participants would have to obtain documentation of sales in the event PJM or the Monitor seeks to review bids.

Randazzo said Ohio's auction is managed by an independent auction manager who, as part of the process, reviews all the bids and makes sure that the structure of the auction and its outcome are competitive. The lowest bid is picked on the recommendation of the auction manager, he said, creating a structure that ensures the outcome is competitive and consistent with prevailing prices. He said it will be much more difficult to come up with a market price after the fact for a capacity product that is unique and dynamic.

"What you're creating is something that's going to subject the results of these auctions to hindsight analysis," Randazzo said. "It's going to reduce the number of suppliers and increase the cost of the product itself."

Jason Barker of Exelon said he also fears reduced liquidity in the state provider of last resort (POLR) auctions could result in less competitiveness and higher prices. He said it is impractical for PJM to try to determine a specific generator source for every megawatt that marketers use to fulfill their winning POLR supply offers.

"Marketers hedge with market products at different points in time," Barker said. "It is fruitless to go behind the POLR auction to try to paint the megawatts that the suppliers use to hedge. PJM could quickly implicate every generator that sells power."

## IMM Alternative

Monitor Joe Bowring presented an *alternative proposal* to PJM's straw proposal. Bowring said compliance with Paragraph 386 should be the simplest method that conforms with FERC's intent and to minimize the impact on state auctions, given that intent.

Bowring said that regardless of how PJM or stakeholders feel about the impacts of Paragraph 386 and whether it should have been included in FERC's determination, the best way to move forward was a narrow interpretation. Otherwise, he said, it could result in a much wider interpretation of the MOPR than was intended by the commission.

In the IMM proposal, resources used to meet a load-serving entity's retail auction obligations would not be subject to the MOPR if the resources are purchased at market rates. Bowring said the IMM defines market rates as "the forward curve for energy for the time period of the retail auction obligation, with a basis adjustment to the zone."

Jason Barker, Exelon | © *RTO Insider*

Bowring said that market rates would also include the PJM capacity market price for the applicable delivery year and locational deliverability area, and PJM ancillary service market prices.

Resources subject to the MOPR would be those already under it and those sold above market rates, Bowring said. The MOPR would also apply to any resource sold to LSEs participating in a retail auction to meet any state-mandated requirements, including renewable energy credits, zero-emission credits, offshore renewable energy credits or any other mandate that limits participating capacity by technology, fuel, location or other attributes.

"The intent is to be as light-handed as possible while still attempting to meet what we interpret to be the commission's intent," Bowring said. ■

# PSEG Turns Bullish on NJ FRR Option

Continued from page 1

units receiving zero-emission credits (ZECs) and offshore wind.

Speaking during a first-quarter earnings call May 4, Izzo said that although capacity prices could be higher under an FRR, the state could see savings because the FRR would require only a 15 or 16% reserve margin. That's far below the margins produced by PJM's Reliability Pricing Model, which have been 24% or more for all but one of the delivery years between 2012/13 and 2020/21, according to one recent study. (See *Report Slams PJM Forecasting, CONE Estimates*.)

"So, the unit cost is more [under FRR], but the number of units is fewer," Izzo said. "The product of the two turns out to be less expensive in the state."

PSEG's nuclear team reduced the scale of the current Salem Unit 2 refueling outage to protect all workers at the site, which also includes Salem Unit 1 and Hope Creek. | *PSE&G*

## Turnabout?

Izzo's comments appear to represent a shift in his thinking. During his fourth-quarter 2019 earnings call in February, Izzo was skeptical that the state would switch to the FRR, saying it would be "overkill" to pull 15,000 MW from the capacity market for 7,000 MW of offshore wind. (See *PSEG's Izzo Skeptical of FRR Option*.)

A PSEG spokesperson said later the next day that Izzo's "'seeming change of opinion' is not a change at all."

"The first comment related to the nature of FERC's chosen solution — that the proposed solution, to allow an FRR-type arrangement for a single unit, was not selected by FERC, and as such, an entire FRR area would be needed, which would be 'overkill' in trying to solve the stated problem. The state's desire to not pay twice for capacity in pursuing a clean energy agenda is perfectly logical, and because of FERC's decision, it will simply need to do so on a broader scale."

In his remarks last week, Izzo cited the likelihood that the 7,500 MW of offshore wind planned by New Jersey by 2035 will be unable to clear the capacity auction under the MOPR. The state awarded a contract for 1,100 MW to Ørsted in June 2019; commercial operation is projected for 2024.

"If you were to ... take a look at what typical Eastern MAAC capacity prices have been and then you factor in what the capacity value of the offshore wind that might be granted by PJM, you quickly get to eight, if not nine figures in just a few years in terms of extra payments on the part of New Jersey customers for not having offshore wind be able to clear the auction," Izzo said. "So, you have this double benefit that the state could realize if it designs the FRR in a competitive way that recognizes the carbon-free resources that it is committed to securing."

Izzo said PJM's MOPR compliance filing proposed an avoidable-cost rate (ACR) price floor for PSEG's nuclear units "that would preserve the full bidding flexibility to clear in the upcoming PJM capacity auction."

"If New Jersey were to implement the FRR auction in broad terms, it would provide a choice for our nuclear units and the majority of our fossil fleet to bid into either PJM's capacity auction or into a New Jersey FRR," he said. "An FRR could be structured to have a longer tenure, a preference for zero-carbon generation and would have locational delivery requirements."

## Very Likely?

"It sounds like ... it's very likely that [New Jersey] probably will go for the FRR option. Is that the way we should be thinking?" asked Glenrock Associates analyst Paul Patterson.

"Look, they're the final decider of that," Izzo responded. "But I think that that is the logical thing for the state to do. Why New Jersey would want to pay twice for capacity in what is obviously an extremely ambitious carbon-free energy agenda would boggle my mind. New solar and offshore wind are not going to clear the auction at these ACRs. So, I think that the state would be greatly incented to do an FRR."

PSEG is in discussions with Ørsted on a potential acquisition of a 25% equity interest in Ørsted's 1,100-MW Ocean Wind project and expects to make a decision this fall. Izzo said the company's decision will not be dependent on whether New Jersey opts for an FRR.

"The state is absolutely committed to building that project," he said. "So, it's really not a question of the FRR at all. The BPU order's quite clear on what the commercial terms of that project ... are and will be."

The BPU is accepting comments on the FRR option through May 20. Izzo said he expected the BPU to make a decision on the FRR no sooner than the end of the year or the first quarter of 2021. "Remember, the state really doesn't have to worry about paying double for capacity now that the nuclear units are covered for at least for the foreseeable future until offshore wind comes online, and that's not going to happen until 2024."

## Consumer Perspective

Stefanie Brand, director of the New Jersey Division of Rate Counsel, said that whether FRR would be cheaper for consumers will depend on whether the program can adequately counter the market power of generators that could supply the state. She also said costs could be impacted by whether the FRR covers the entire state or just the Public Service Electric and Gas zone.

"There aren't going to be too many companies that are going to be in a position to set up an FRR. So, there's going to be a market power element that's going to have costs in it," she said in an interview May 5. Izzo "doesn't include that in his equation. And it's money that might be going to his company, so that may have been the reason why it was included" in his comments.

Brand said her office hasn't come to a conclusion on the wisdom of an FRR and hopes to learn more from an analysis PJM's Independent Market Monitor is doing on a potential New Jersey FRR. The Monitor issued an *analysis* on the impact of Exelon's Commonwealth Edison leaving the capacity market for an FRR in December and one on *Maryland*'s options April 17 that concluded ratepayers are likely to see cost increases under an FRR. (See *PJM Monitor Defends FRR Analyses in MOPR Debate*.)

"We deregulated generation with the idea that competition was going to bring positive impacts in terms of [lower] prices. And it actually did for a long time," Brand said. "We've kind of all been thrown into a frenzy right now. But I wouldn't want to return to a situation where we had just a single unregulated monopoly. I don't think that's going to be a good outcome."

Brand said her two biggest concerns over the MOPR are how it affects offshore wind and the state's basic generation service (BGS) *auctions* held by PSE&G and the state's three other distribution utilities to provide service to customers not served by a competitive retailer.

In its April 16 order largely rejecting rehearing of its December MOPR ruling, FERC said the BGS is a "state subsidy because it is a state-sponsored process and includes indirect payments to the resource." (See *FERC: RGGI, Voluntary RECs Exempt from MOPR*.)

"I don't have a whole lot of basis to really check his math. … It may end up being cheaper" to leave PJM, Brand said. "We really need a full analysis of what we think the costs are going to be before we jump to any kind of conclusion. It could be that if [nuclear generation, solar and energy efficiency] clear, then we just figure out a way to deal with the offshore wind problem [separately] and stay exactly where we are right now."

## COVID Impact

Izzo also talked about the impact of the coronavirus pandemic, saying the company's PSE&G and PSEG Long Island units — which serve some of the areas with the highest incidence of confirmed COVID-19 cases — have suspended nonessential fieldwork while continuing emergency work.

Izzo said infection rates among PSEG's 13,000 employees are below those for New Jersey and Long Island as a whole. About 1% of the workforce is currently self-monitoring.

The company is continuing its work on critical energy infrastructure projects, although PSEG's nuclear team reduced the scale of the current Salem Unit 2 refueling outage to protect all workers at the site, which also includes Salem Unit 1 and Hope Creek.

Izzo said that the pandemic could result in "lumpy" access to mutual-aid resources, noting that during a recent storm, the company was able to secure only about 40% of the assistance it sought from other utilities.

"It was a combination of, candidly, utilities not willing to risk their own employees in terms of their exposure … and travel limitations put on some of the contractors," he said. "So, if we have that experience when the trees all have leaves on them and the wind blows, then we will have to communicate extensively with customers about some of the likely delays that they will experience in being restored."

Photos show damage from a storm in South Jersey in April. PSEG said it received only 40% of the mutual aid assistance it sought from other utilities because of the pandemic. | *PSE&G*

## Earnings

PSEG *reported* non-GAAP operating earnings of $520 million ($1.03/share) in the first quarter, a drop from $547 million ($1.08/share) in 2019. Net income under GAAP was $448 million ($0.88/share) compared to $700 million ($1.38/share) in Q1 2019.

The company said its results were aided by rate-based expansion from transmission and distribution investments at PSE&G and ZEC revenue for PSEG Power, which added 7 cents/share.

Those gains were offset by a scheduled decline in capacity prices, which reduced operating earnings by 11 cents/ share, and the second-mildest first quarter ever recorded in New Jersey.

PSE&G said pandemic stay-at-home orders caused a weather-normalized decline of 5 to 7% in electric load from the end of March through April. It said the ranges and the mix of usage among residential, commercial and industrial customers are imprecise because New Jersey lacks advanced metering infrastructure. (Izzo said the company hopes to complete BPU proceedings allowing it to spend $600 million on advanced metering infrastructure and $400 million on electric vehicle energy storage programs by early next year.)

CFO Daniel J. Cregg said that although PSE&G temporarily suspended all non-safety-related service shutoffs for nonpayment during the COVID-19 crisis, the company can recover bad debt expenses through the state's "societal benefits charge."

Beginning June 1, the average PJM capacity price will rise to $168/MW-day from $116/MW-day, Cregg said. A scheduled decline in ISO-NE capacity prices will be partially offset by its nearly year-old Bridgeport Harbor 5 plant, which has a seven-year capacity lock at $232/MW-day.

PSEG Power has hedged more than 95% of its production at an average of $36/MWh for the remainder of 2020. It has hedged more than 55% of forecasted production at an average of $35/MWh for 2021 and more than 25% of output at $35/MWh for 2022. ■

PJM News

# Clock Ticking on Exelon Illinois Nukes Under MOPR

*Continued from page 1*

price rule (MOPR) since 2018. (See *Illinois: End PJM Capacity Market?*) The legislature is considering two bills that would create a fixed resource requirement (FRR) for the Commonwealth Edison territory in Northern Illinois, replacing the PJM capacity auction with an auction run by the Illinois Power Agency (IPA).

But company officials said during a *first-quarter earnings* call Friday that they don't know if the legislature, which largely suspended operations in mid-March in response to the coronavirus pandemic, will return before the term ends May 31.

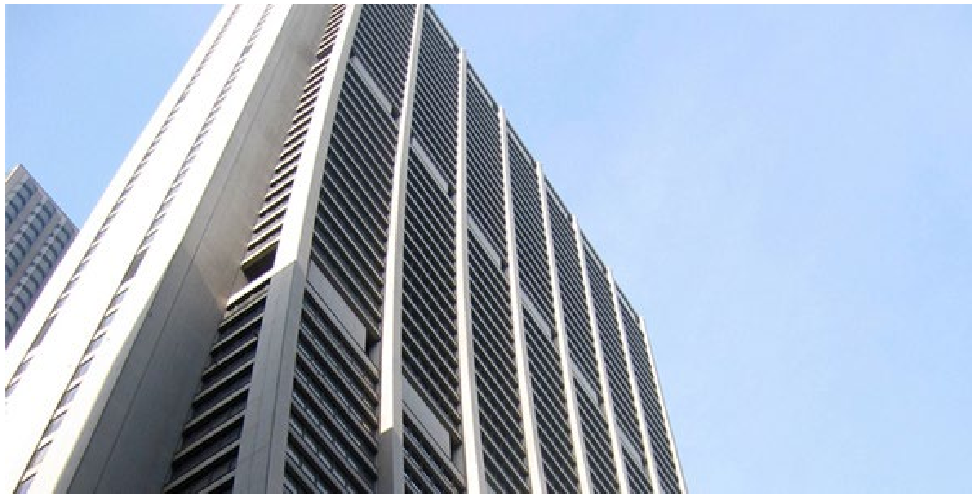
Kathleen Barrón, senior vice president of government and regulatory affairs and public policy, said that although the legislative session ends in May, lawmakers could return this summer with an agreement between the House speaker and Senate president. The governor also could call a special session, she said.

Barrón said she was pleased to see the state Department of Public Health issue guidance for how the legislature could return safely to the capital. "That is good progress, but it remains to be seen whether the leaders will decide to bring folks back to Springfield this session," she said.

CEO Chris Crane said Exelon officials have been "stressing the importance" to lawmakers of addressing the threat posed to nuclear and renewable generation by FERC's December order expanding the MOPR to new state-subsidized resources.

PJM has said it will hold the next Base Residual

Exelon CEO Chris Crane | © *RTO Insidert*



Exelon's corporate headquarters inside Chase Tower in Chicago

Auction about six and a half months after FERC rules on its MOPR compliance filings — meaning an early 2021 auction if a ruling comes by mid-2020.

"So, we're up against a clock. And once those auctions are run, we're highly confident that minimal or [none] of our clean megawatts will clear in that capacity auction," Crane said. "They'll be replaced by fossil units, which is detrimental to the state's goal of being 100% clean by 2030."

## Proposals

Exelon in March 2019 *endorsed* the Clean Energy Progress Act (CEPA) (HB *2861*), which would create a ComEd FRR. The bill cleared the House Public Utilities Committee at the end of that month by a *voice vote* but has seen no action since. The bill currently lists 16 co-sponsors.

The Citizens Utility Board, the Environmental Defense Fund, the Natural Resources Defense Council and others calling themselves the *Illinois Clean Jobs Coalition* are backing the *Clean Energy Jobs Act* (CEJA) (SB *2132*/HB *3624*), which also would create an FRR. It has 33 Senate sponsors and 59 in the House.

"We certainly agree that the only cost-effective way to reach 100% clean energy is to take advantage of the FRR," David Kolata, executive director of the Citizens Utility Board in Chicago, said in an interview Monday.

Meanwhile, the American Wind Energy Association and the Solar Energy Industries Association are among 70 business, nonprofit and organized labor groups backing the *Path to 100 Act* (*HB 2966/SB 1781*), which would increase Illinois' renewable portfolio standard to 40% by 2030 and add new funding for renewable generation. It does not include an FRR.

Jeff Danielson, AWEA's central states director, said the Path to 100 is intended to address the "funding cliff" for the RPS program, which has left the IPA without any more funding for utility-scale wind and solar. "The primary issue on energy policy we need to address is to meet the RPS funding goal," Danielson said.

Kolata said that while the Exelon-backed bill is focused on the FRR and the Path to 100 on expanding the RPS, the CEJA is more comprehensive. It would increase natural gas efficiency standards and direct the IPA to cut peak electricity demand through energy storage, efficiency and special rate plans. It would seek to eliminate 1 million gasoline and diesel vehicles by increasing development of electric vehicle charging stations, EV ridesharing and public transportation electrification. CEJA also would add 40 million solar panels and 2,500 wind turbines in the state, quadrupling the amount of new renewable energy created by the 2016 Future Energy Jobs Act, which ordered utilities to get 25% of their power from renewable resources by 2025 and approved zero-emission credits (ZECs) for Exelon's Quad Cities and Clinton nuclear plants.

In his State of the State address in January, Gov. J.B. Pritzker called for passage of legislation this term to reduce carbon pollution, promote renewable energy and accelerate electrification of transportation. "Urgent action is needed. But let me be clear, the old ways of negotiating energy legislation are over," Pritzker *said* in what some saw as a reference to the FBI investigation into ties between the legislature and Exelon's team of lobbyists. "I'm not going to sign an energy bill written by the utility companies." (See *Exelon Pledges Reforms amid Grand Jury Probe*.)

Chicago radio station WBEZ *quoted* Pritzker as refusing to commit to any timetable on responding to Exelon's concerns. "I've said we're going to make sure that we work on an energy package for the state, and we don't need the high-paid lobbyists to be guiding that for us," Pritzker said Friday. "I look forward to the legislature getting together to address so many challenges that we have. But is it true there are higher priorities right now? Yes, there are, and that's reviving our economy."

Exelon's ComEd also suffered a blow last month when the Illinois Commerce Commission disavowed its "NextGrid: Illinois' Utility of the Future" study after agreeing to settle a lawsuit that alleged the former head of the ICC had given the utility veto rights over the study and its participants. (See *'NextGrid' Goes off the Rails*.)

Nevertheless, Crane said Friday that the company has "significant support" for its efforts to create an FRR.

"We would hope that it would get done before the end of the session. That's what we've stressed: to give the IPA time to be able to develop their own auction process that will allow us to break away on capacity needs for the state of Illinois from PJM. ... It's a very tight time frame. … This is a very important issue to address … along with the state budget and some other large issues. So, we know there's a will to get to work. It's just the way to get to work and how fast we can get this done."

Exelon spokesman Paul Adams told *RTO Insider* on Monday that while the company prefers the CEPA, it also "directionally supports" the FRR envisioned in the CEJA.

Both bills promise 5% initial savings compared with what ratepayers currently pay for capacity, ZECs and renewable energy credits. Neither bill calls for an expansion of the state's ZEC program to Exelon's other nuclear plants in the state: Dresden, Byron and Braidwood.

In its first-quarter *filing* with the U.S. Securities and Exchange Commission, Exelon said its Dresden, Byron and Braidwood plants are "showing increased signs of economic distress, which could lead to an early retirement." It said PJM's last capacity auction in May 2018 "resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood."

Adams said those plants would be eligible for "clean capacity" payments under the FRR as envisioned in the CEPA. Quad Cities, which is located in the PJM portion of Illinois, would continue to receive ZEC payments but would be ineligible to receive a clean capacity payment under the FRR legislation to avoid double recovery, Adams said.

In addition to being aligned with the state's carbon-free goals, CUB's Kolata said the CEJA will save consumers in large part by reducing ComEd's reserve margin to 16% under the FRR versus the nearly 30% under PJM's Reliability Pricing Model (RPM).

Kolata said the IPA would first procure carbon-free capacity — which would receive compensation for their environmental attributes — and then procure fossil fuel resources for any residual needs. Kolata said he expects 16 GW of fossil capacity to compete for 5 GW of residual need in Northern Illinois.

Not everyone is convinced the FRR will be cheaper, however. In December, PJM's Independent Market Monitor issued an *analysis* that concluded net load charges would increase 23.6% if ComEd procured all of its capacity obligations outside of RPM at the offer cap — $254.40/MW-day — rather than the $195.55/MW-day clearing price in the 2021/22 BRA.

In a second scenario, the Monitor calculated that ComEd's load charges would decrease 5% if the price negotiated for its capacity were equal to the locational deliverability area's clearing price. The report contended the first scenario was more plausible, "given Exelon's assertions that the current total revenue from energy, ancillary and capacity markets is not adequate for its nuclear plants."

## Earnings

Exelon's first-quarter earnings beat the Zacks Investment Research analyst *consensus* by 2 cents/share, but the company reduced its earning guidance for the full year because of decreased demand during the pandemic.

CFO Joseph Nigro said the company earned $582 million ($0.60/share) on a GAAP basis compared to $907 million ($0.93/share) in the first quarter of 2019. Nigro said non-GAAP operating earnings were flat from last year at 87 cents/share, slightly below the midpoint of the company's guidance range.

Nigro said Exelon was "particularly pleased" with the results considering the warm winter weather throughout the region.

"Temperatures in the Mid-Atlantic were 5 to 7 degrees higher than average in January through March, costing us 14 cents/share between Exelon Generation and our non-decoupled utilities," Nigro said.

## COVID-19 Impacts

Besides the warm winter weather, Nigro said the effects of the pandemic's stay-at-home orders had the most dramatic effect on energy demand. He said because of the pandemic, the unfavorable weather and lower allowed electric distribution returns on equity at ComEd because of a decrease in U.S. Treasury bill rates, Exelon was revising its 2020 full-year guidance range from $3 to $3.30/share to $2.80 to $3.10/share.

"While typically we would not change guidance so early in the year, we want to provide a complete picture of where we stand at this point in the year and include our best estimates of the COVID-19 impacts," Nigro said.

Exelon officials expect commercial and industrial load to decrease by 9 to 15% and residential load to increase by 4 to 7%, depending on the region, during the second quarter. Nigro said the company recognizes the situation surrounding the pandemic changes rapidly, so they've taken a "cautious view of the world" when revising the numbers.

"The full impacts, including the duration and structural changes to the economy, continue to evolve," Nigro said. "In developing our revised guidance range, we looked at the load and economic data we were seeing in April, talked to our customers about their expectations for the year and considered different economic outlooks."

## Acquisition Opportunities?

Guggenheim Securities analyst Shar Pourreza asked company officials whether the economic distress resulting from the pandemic could present strategic opportunities for Exelon's Constellation retail business.

Constellation CEO James McHugh said the company would kick the tires of any retail operations that became available.

"Our strategy before will stay the same, which is we would be looking to buy … books of business that we could easily fit into our platform," he said. "We've developed, I think, a world-class platform over the years that we can integrate easily, and we've shown that before when we bought books of business." ■

## PJM News

# Dominion Undecided on FRR Option

By Rich Heidorn Jr.

While Exelon and Public Service Enterprise Group last week expressed support for pulling out of PJM's capacity auction over the expanded minimum offer price rule (MOPR), Dominion Energy says it is undecided.

Exelon and PSEG officials discussed their views of the fixed resource requirement (FRR) option during their quarterly earnings calls. (See related stories, *Clock Ticking on Exelon Illinois Nukes Under MOPR* and *PSEG Turns Bullish on NJ FRR Option*.)

But Dominion told the Virginia State Corporation Commission in its proposed *integrated resource plan* May 1 that it is still evaluating the FRR alternative in response to FERC's December order expanding the MOPR to new state-subsidized resources and "has made no decision at this time."

"If the company were to elect FRR, it would have to do so in advance of the next RPM [Reliability Pricing Model] base auction," Dominion said. "Typically, this election would need to happen about six months prior to that auction; however, due to the pending MOPR-related filings with FERC, the schedules may be compressed. The schedule depends on if, and when, FERC accepts PJM's recent compliance filing."

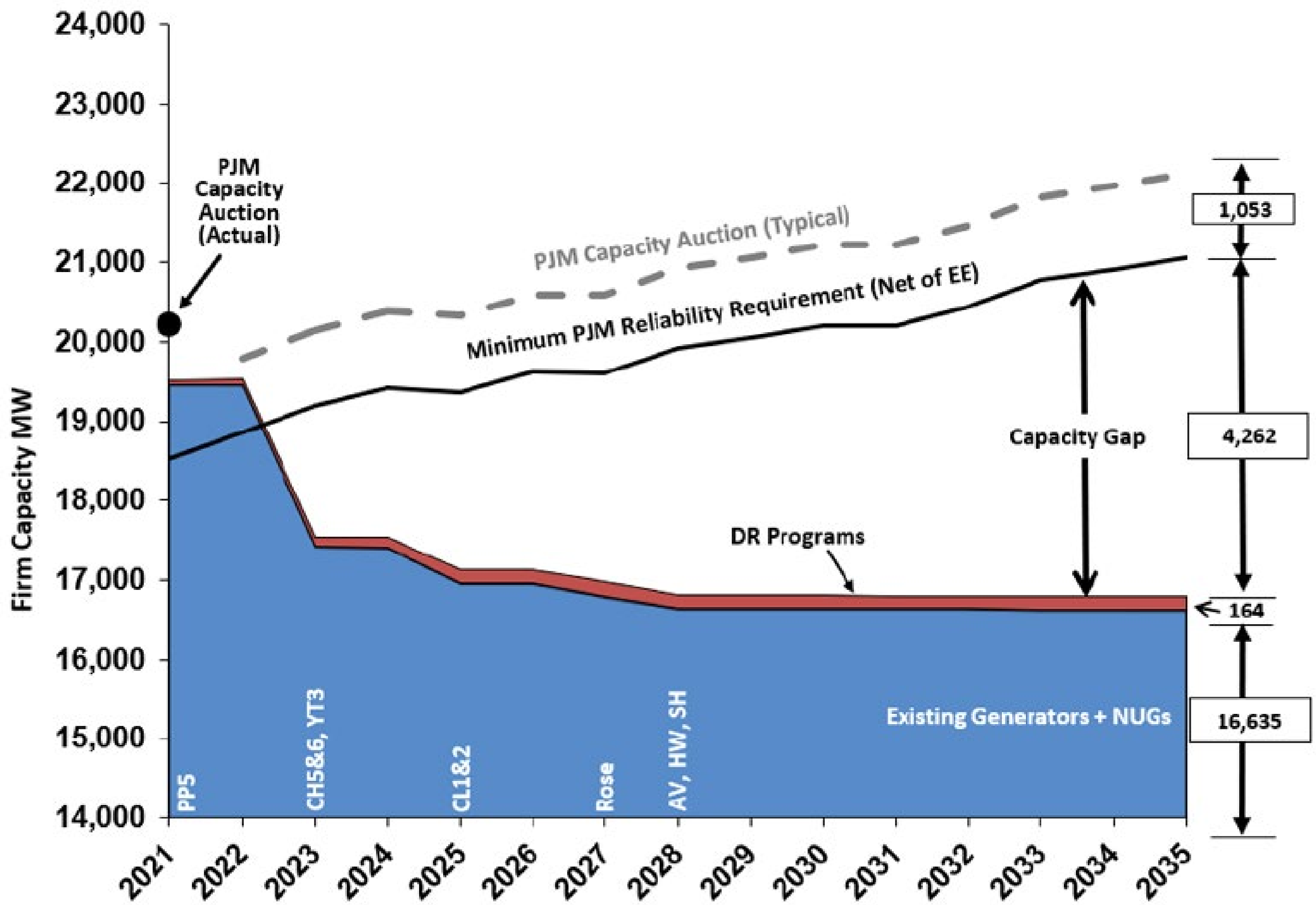
PJM currently estimates the next Base Residual Auction to occur in late 2020 or early 2021, about six and a half months after FERC rules on the RTO's compliance filings.

FERC had previously exempted from MOPR self-supply resources owned by public power entities (cooperative or municipal utilities), vertically integrated utilities subject to traditional bundled rate regulation like Dominion and load-serving entities that serve retail customers.

But in the Dec. 19 order, FERC said new self-supply resources would no longer be exempt, ruling that they suppress capacity prices under PJM's RPM. The commission said the self-supply exemption would be limited to resources that had either cleared the RPM or were in development and in PJM's interconnection queue before the December order.

Dominion asked FERC to expand eligibility for the self-supply MOPR exemption to any resource that is planned under a self-supply entity's IRP. (See *Dominion: FERC MOPR Rulings Inconsistent on Self-supply*.)

But in its April 16 *rehearing order*, the commission rejected Dominion's request. "Integrated resource plans do not replace the PJM




Dominion capacity position 2021 to 2035 | *Dominion Energy*

# PJM News

interconnection process; granting rehearing in this manner would expand the number of resources eligible for the exemption beyond those that reflect established investment decisions, to include resources that may not even be sufficiently developed to be in the PJM interconnection process at all," FERC said. "We find that the demarcation clarified above is sufficient to recognize those resources that are sufficiently along in the interconnection process to warrant exemption under the commission's stated goals." (See *FERC: RGGI, Voluntary RECs Exempt from MOPR*.)

Dominion Energy Virginia, which owns 27,100 MW of generation, is planning to build 2.6 GW of wind generation off the coast of Virginia and is about halfway through a plan to add 3,000 MW of solar generation. Its proposed IRP for 2021-2045 would quadruple the amount of solar and wind generation in its previous 15-year plan, a response to Gov. Ralph Northam's executive order on climate change and the Virginia Clean Economy Act, signed last month. (See *Va. 1st Southern State with 100% Clean Energy Target*.)

In its discussion of the FRR option, Dominion noted that American Electric Power, parent of Appalachian Power in Virginia and West Virginia, is "the only significant utility in PJM" to have adopted FRR.

"Because of its five-year minimum commitment requirement, risks to FRR election should be carefully weighed against the benefits," Dominion told the SCC. "Risks include future environmental changes, regulatory changes, zonal constraints, and capacity and energy market changes. The potential benefits of FRR election include [a] lower required reserve margin and the absence of MOPR risk to new generation used to meet the load obligation."

Under the expanded MOPR, Dominion said, "virtually all new generation resources will need to offer at net [cost of new entry] or an otherwise calculated market seller offer cap — which could be above the RPM market clearing price — resulting in $0 revenue for these uncleared resources." (See *MOPR Ruling Threatens to Upend Self-supply Model*.)

Dominion said the reliability requirement for the FRR service area would be the forward load forecast plus the target reserve margin. "This is one of the primary differences between RPM and FRR, as the PJM coincident peak target reserve margin for FRR is forecasted to be approximately 15% — over 5% less than where the RPM market has been clearing recently. From a long-term planning perspective, this reserve margin requirement difference could be significant. If the company's forecasted load was 20,000 MW, for each percent difference between [the] cleared reserve margin and target reserve margin, electing FRR would result in about a 200-MW reduction in [the] purchase requirement."

But the company cautioned that "both the clearing price and the clearing reserve margin of the upcoming RPM forward capacity market remain highly uncertain."

And it noted that capacity resources committed under an FRR plan will continue to be subject to the same Capacity Performance requirements as those committed through the RPM. "To the extent an LSE has capacity in excess of its load requirement, those excess capacity resources may not generate the same revenue as if offered into the RPM market," it said. ■

## SPP News

# SPP Extends COVID-19 Measures Through July

## *ERCOT Suspends In-person Meetings for 'Foreseeable Future'*

*By Tom Kleckner*

During SPP's Board of Directors web meeting last month, one stakeholder commented on the number of beards grown by fellow sheltered-at-home stakeholders.

"One thing about growing a COVID-19 beard," said Dave Osburn, Oklahoma Municipal Power Authority's general manager, "I hope I don't look like Billy Gibbons before this is over."

Osburn may yet give ZZ Top's front man a run for his facial follicles. On Friday, SPP said it was extending its suspension of its business travel and face-to-face meetings until Aug. 1 at the earliest.

The action will convert SPP's July quarterly governance meetings to virtual webinars, as happened in April. The stakeholder groups last met in person in January, with their next face-to-face meetings scheduled in October.

"We look forward to the day we can conduct our meetings in person again, but we won't until we're certain we can do so safely," SPP CEO Barbara Sugg said in a message to stakeholders. "We've now proven we can facilitate our stakeholder process virtually when necessary."

The move comes as no surprise to Rob Gramlich, president of Grid Strategies.

"I find it hard to imagine people traveling for stakeholder meetings in July," he said. "So many people call into these meetings that it would be hard to say having them face to face is essential or worth taking any risks about."

On Monday, ERCOT followed suit and said that its stakeholder meetings will continue to operate remotely for "the foreseeable future." The same timeline applies to visitors at the grid operator's facilities, where only those employees who can't work from home are in their offices.

ERCOT said it consulted with the Technical Advisory Committee and its subcommittee leadership. Together, they determined social distancing guidelines made it untenable to hold medium-to-large stakeholder meetings at the grid operator's facilities without endangering the health of attendees.

TAC leadership has proposed procedure changes that will allow the committee to hold votes during conference calls. The group will discuss the changes during its May 27 information session.

ERCOT follows federal, state and local health agency guidance, along with epidemiologist recommendations in making its decisions.

SPP said it extended its suspension based on feedback from its member companies regarding their own pandemic response plans.

"The health and safety of our employees and their families remains a top priority for SPP and is key to our reliable delivery of services," Sugg said, noting staff have not recorded any confirmed cases of COVID-19.

Billy Gibbons, ZZ Top

SPP staff have been working at home since mid-March. When it is safe to return to the office, as Sugg says, staff will do so in a staggered approach, a fifth of the employees at a time. (See "Sugg says RTO to Open Very Carefully in Months Ahead," *SPP Joint Quarterly Stakeholder Briefing: April 27, 2020*.)

The RTO's facilities and incident command structure teams will have personal protective equipment available and a supply line to restock when staff begin their phased returns to campus, Sugg said.

SPP's systems remains reliable, though staff are tracking small but steady reductions in load, she said. Load is down 8 to 10% across the system compared to similar days and temperatures in recent years. ■

SPP's corporate campus will remain mostly silent in the near term. | *WER Architects*

## Company News

# NRG's Q1 Retail Earnings Stave off COVID Declines

*By Michael Kuser*

NRG Energy's first-quarter net *income* rose 29% to $121 million ($0.49/share) on the addition of a new revenue stream from a recent acquisition and margin enhancement initiatives partially offset by mild weather across core markets.

In a call with analysts Thursday, CEO Mauricio Gutierrez touted the company's strong position despite the social disruptions stemming from the coronavirus pandemic.

"First, we initiated a comprehensive response to COVID-19 focusing on maintaining safe and reliable operations," Gutierrez said. "Second, given the changes that we have made to our integrated business, we were able to deliver strong results during the first quarter and reaffirm our full-year financial guidance."

Gutierrez also highlighted enhanced disclosures on the business, including the introduction of new integrated regional segments, with the company working to integrate its Eastern markets in the same manner it has in ERCOT, where it "moved from having two distinct businesses, Retail and Generation, to one integrated business with a regional focus."

The company's West segment will only have generation revenue and cost set, as there is no ability to replicate the integrated model because of a lack of competitive retail markets, he said.

"Because the East and West segments are not fully integrated, the sensitivity to changes in power prices is not as optimized as it is in Texas," Gutierrez said.

### Texas Rides High

CFO Kirkland Andrews noted that NRG as a whole saw $349 million in earnings during the first quarter. The company's Texas segment

| *NRG*

accounted for $195 million, up $19 million largely because of the increased load from the acquisition of Stream Energy last year.

But the company reported power demand declines across all regions, except for that of ERCOT residential, which saw a 7% rise last month.

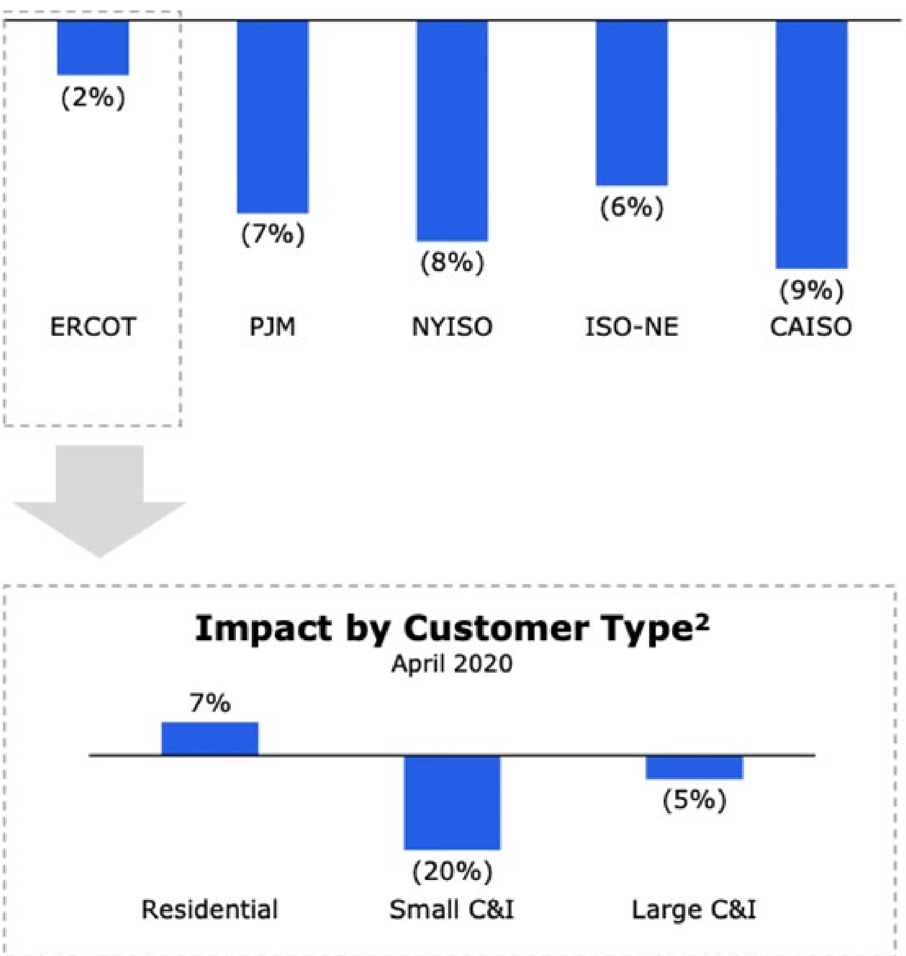
"To put the mild weather into context, ERCOT and the Northeast saw temperatures that were 20% and 17% warmer than the 10-year normal for the first quarter," he said.

In these "unprecedented times," Gutierrez said to "expect most of the adverse impact from COVID-19 to come from customer payment-related items, like bad debt. At this point, we estimate that to be around $50 million. We will look at and be studying this impact through prudent cost management and ERCOT's relief fund."

While the small business, commercial and industrial sectors have been negatively impacted, the impact on specific utilities will depend on the customer mix in their portfolios, Gutierrez said.

"In our case, we are heavily weighted towards the Texas residential customer," he said.

Looking ahead to summer, Gutierrez noted that "Texas already began a partial reopening of the economy. This suggests that the severe impact to small businesses we have seen in April may ease as the economy reopens. ... The impact to summer load is difficult to assess at this point, but I can tell you that summer prices will be dependent on wind production and weather." ■




Load reductions by RTO/ISO in April 2020 | *NRG*

*Call transcript courtesy of Seeking Alpha.*

## Company News

# Vistra Earnings up as it Deals with New Normal

*By Tom Kleckner*

Vistra CEO Curt Morgan | © *RTO Insider*

In announcing first-quarter earnings that beat expectations, Vistra Energy CEO Curt Morgan said last week that the company took steps early in the year to prepare its operations for the harm wrought by the COVID-19 pandemic.


Luminant's Odessa-Ector gas-fired power plant | *Luminant*

Morgan is still getting used to the new normal.

"I never thought I would be hosting an earnings call from my home with my management team dispersed across the [Dallas-Fort Worth] metroplex," he said told financial analysts May 5. "Yet, that is where we find ourselves today in these challenging times."

Vistra *reported* adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) of $850 million, as compared to $824 million for the first quarter of 2019. The company reaffirmed its 2020 adjusted EBITDA guidance range of $3.29 billion to 3.59 billion.

The Irving, Texas-based company uses adjusted EBITDA as its performance measure, saying this helps investors analyze the business.

In February, Vistra began suspending nonessential business travel and restricted access to corporate offices and plants. Morgan said the company was one of the first to test employees' temperatures and use entry questionnaires at its facilities. He credited its proactive measures with completing or being on schedule with 86 maintenance outages at its Luminant plants "to ensure plant reliability for the critical summer months ahead."

"Had we been levered like the [independent power plants] of the past, like back in 2016 when we emerged from bankruptcy, we may be having a very different discussion today," Morgan said, a reference to its Energy Future Holdings predecessor, which eliminated $33 billion of debt before transitioning to its current form. (See *Luminant, TXU Energy Emerge from Bankruptcy*.)

Morgan said about 70% of its adjusted EBITDA comes from the ERCOT market, which — as in the aftermath of the 2008-2009 recession — "is proving to be relatively resilient." ERCOT *tweeted* the same day that its recent weekend peaks "appear" to have returned to pre-COVID levels and its weekday peaks are now down only 2%.

"We believe Vistra Energy is well positioned to deliver strong financial results in 2020, even in the face of lower demand driven by COVID-19," Morgan said.

Vistra's share price opened May 5 at $20.68 following the earnings release but finished the day down at $18.72. Shares had closed the previous day at $19.01. ■

## Company News

# Entergy Weathers Early COVID-19 Effects

*By Tom Kleckner*

Entergy on Monday reported "solid" earnings in the first quarter, saying it has taken quick action to mitigate the effects of the COVID-19 pandemic.

Entergy's Searcy Solar project in Arkansas was one of two 100-MW solar farms recently granted regulatory approval.| *Entergy*

First-quarter earnings came in at $119 million ($0.55/share), down from a year ago when earnings were $255 million ($1.32/share). Adjusted earnings were $230 million ($1.14/share), beating Zacks Investment Research analysts' estimate of 94 cents/share.

Entergy activated its pandemic plan in mid-January. It has implemented a $100 million spending reduction for 2020 — primarily because of mild weather in the first quarter and expected bad debt from customers unable to pay their bills — and received regulatory orders to defer pandemic-related costs.

"We were prepared, and we will remain diligent, focused and flexible to ensure we make the right decisions at the right time to mitigate the effects for all of us," CEO Leo Denault said, noting the company's major projects remain on track and its capital plan is unchanged. "We're stepping forward, not back, to be leaders in our communities when they need us the most."

The pandemic continues to pose headwinds for the company. Rod West, group president of utility operations, said Entergy is expecting industrial sales to drop about 7% and commercial sales to fall 9.5%, largely as a result of refinery reductions and delays in new customers. Residential sales are projected to grow about 2%.

West said the New Orleans-based company expects industrials to return as growth drivers in 2021 and 2022 "as the commercials and residential normalize to our previous COVID-19 point of view." Entergy expects revenue to fall by as much as $140 million because of the pandemic.

An Entergy transmission tower | *Entergy*

"Uncertainty remains as to the depth and length of this pandemic," Denault said in affirming the 2020 adjusted earnings guidance range of $5.45 to $5.75/share.

Entergy continues to replace older generation with cleaner and more efficient assets, Denault said. The company brought its 980-MW gas-fired Lake Charles Power Station online months ahead of schedule in March and expects to energize its 128-MW New Orleans Power Station in June. Entergy also received regulatory approvals for two 100-MW solar farms in Arkansas and Mississippi, to be completed in 2021.

Entergy's share price, which closed at $95.01 last week, dropped to $93.75 just before the earnings call but finished the day at $96.22. ■

## Company News

# COVID-19 Takes Bite out of AEP's Q1 Earnings

*By Tom Kleckner*

Count American Electric Power — one of the nation's premier electric utilities — among those companies whose environment has been turned upside down by the COVID-19 pandemic.

The utility on Wednesday *reported* first-quarter earnings of $495 million ($1/share), down 13.5% from 2019's opening-quarter earnings results of $573 million ($1.16/share). The company said revenue fell almost 10% to $3.7 billion, and electricity sales were off 12% during the quarter.

Wall Street reacted to the news on Wednesday by trading AEP's share price down 5.5% from the previous day's close to $78.82. The company's stock has lost nearly a quarter of its value since hitting an all-time high of $104.97 on Feb. 18, as the COVID-19 outbreak was heating up.

"When there is a pandemic like the one we're experiencing today that has not occurred in 100 years, and this nation's economy has been effectively shut down for months, there is no question that everyone is challenged, and AEP is no exception," CEO Nick Akins said during a conference call with financial analysts.

The second quarter has not been much better. Akins said new data indicate total April sales were down 4.3% from a year ago, with 10% and 7.7% drops in industrial and commercial sales, respectively, which more than offset a 6% increase in residential activity.

The Columbus, Ohio-based company has reaffirmed its 2020 operating earnings guidance range of $4.25 to $4.45/share and its 5 to 7% long-term growth rate. However, management expects to be in the lower half of its guidance, due to revised load assumptions related to COVID-19.

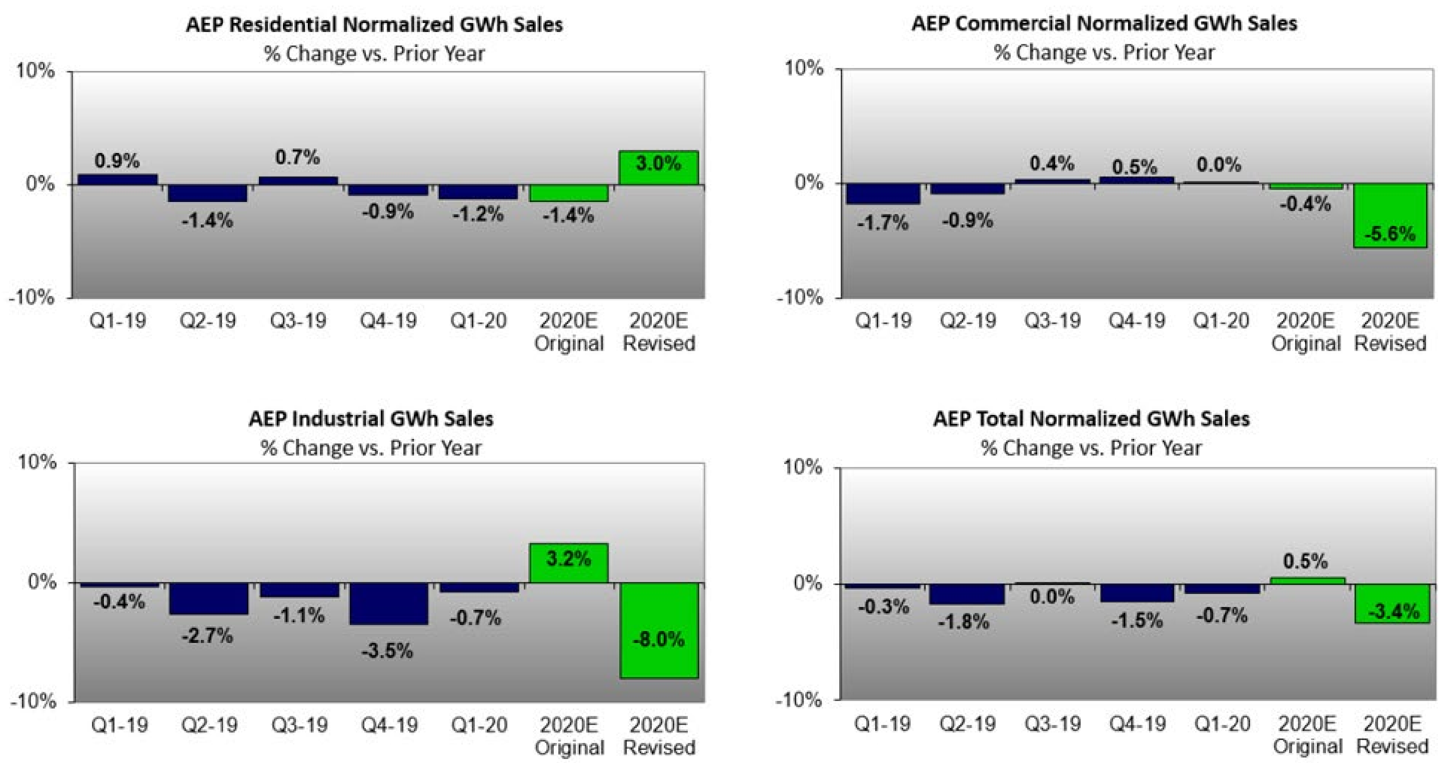
"Regardless of whether we forecast a V-shape, a U-shape or W-shape COVID-19 recovery," Akins said, "we see our service territory as an arbitrage between residential load and commercial/industrial load that is defined really by a pendulum between the financial characteristics of working from home versus the restart of commercial and industrial businesses."

Referencing boxer Mike Tyson's comment that "everyone has a plan until they get punched in the mouth," Akins said, "Yes, we've been challenged a little bit, but we are very much still in the match."

To counteract the loss of sales, AEP has cut planned operations and maintenance expense by $100 million and shifting $500 million of its planned 2020 capital spending into future years. Akins said the company still plans to invest $33 billion over the next five years.

The future capital investment does not include AEP's $2 billion North Central Wind Project, composed of three wind farms in Oklahoma that will produce 1.49 GW of capacity to consumers in the company's Oklahoma and Louisiana service territories. The project has received regulatory approval in Arkansas and Oklahoma and from FERC, but Louisiana and Texas have yet to weigh in.

Akins said the regulatory proceedings are on schedule and the project is moving forward. "That was the importance of Arkansas' approval," he said, noting that the state can increase its megawatt allocation should another Southwestern Electric Power Co. state reject the application. ■




AEP is forecasting an overall 3.4% decline in sales this year. | *AEP*

## Company News

# Eversource Q1 Earnings Unfazed by Pandemic

By Michael Kuser

The COVID-19 pandemic might not have impacted Eversource Energy's first-quarter earnings, but it is affecting the company's business both as a frontline utility and developer of offshore wind energy projects, analysts heard last week.

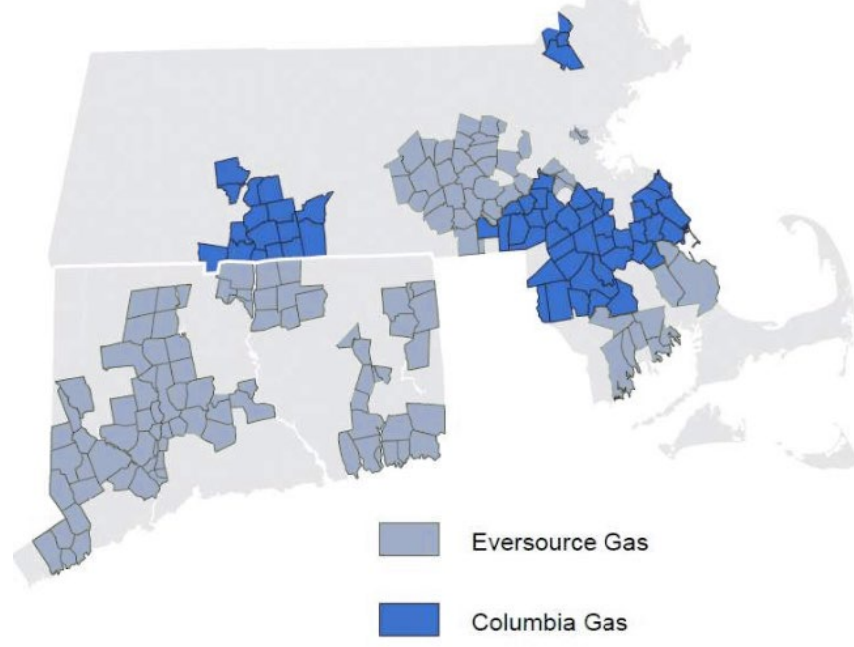
Most of the company's customer service staff are working from home, and state regulators have delayed two rate case decisions until fall. And while federal officials are keeping up with offshore project reviews, a New York judge has delayed by 10 weeks a state-mandated hearing into the company's 130-MW South Fork project off Long Island.

During an analysts call Wednesday, Eversource reported first-quarter earnings of $334.8 million ($1.01/share), up more than 8% from the same period a year ago.

Eversource is New England's largest utility company, with regulated subsidiaries offering retail electricity, natural gas, and water service to approximately 3.6 million customers in Connecticut, Massachusetts and New Hampshire.

The company is about to get bigger, confident that it will receive regulatory approval for its $1.1 billion acquisition of Columbia Gas' 320,000 natural gas customers in Massachusetts.

"We are acquiring the assets of Columbia Gas of Massachusetts, not any of the liabilities associated with the tragic September 2018 incident in the Merrimack Valley," CFO Philip Lembo said in an earnings call.




Eversource is waiting for DPU approval of its $1.1 billion purchase of Columbia Gas, with closing expected by the end of Q3 2020. | *Eversource*

### Current Rate Cases

New Hampshire Gov. Chris Sununu issued an executive order last month that will allow state regulators to delay ruling on a Eversource subsidiary Public Service Company of New Hampshire's request to raise annual base distribution rates by approximately $70 million. The decision, originally slated for July 1, will be pushed to November, Lembo said.

PSNH implemented a temporary $28 million rate increase effective July 1, 2019, which will remain in effect until permanent rates are set. Any difference between the temporary rates and the permanent rates will be reconciled back to that July time frame.

In Massachusetts, the company's NSTAR gas subsidiary is seeking a $38 million base rate adjustment, having agreed to a one-month delay with a decision now expected at the end of October and rates effective on Nov. 1, Lembo said.

In addition, a new three-year grid modernization work plan for 2021-2023 will be filed in Massachusetts this summer, and Connecticut regulators on Wednesday issued an *order* requesting proposals on program designs for a number of initiatives related to grid modernization, with proposals due by the end of July, he said.

### Sailing Close to the Wind

Eversource's offshore wind energy partnership with Ørsted on March 13 filed a construction and operations plan (COP) with the Bureau of Ocean Energy Management for the 704-MW Revolution Wind project.

"BOEM's review of that project has begun, and we expect to have a full schedule for that review later this year," Lembo said. (See *Offshore Wind Slogs Forward in Massachusetts*.)

"We have not yet received a new schedule from BOEM on its review of the 130-MW South Fork project. The COP on that was filed back in 2018, but the process was paused last year so that we could update the project for our new 1-nautical-mile-by-1-nautical-mile configuration. We expect the new schedule to be posted by midyear."

The companies last October signed a contract with New York for the 880-MW Sunrise Wind offshore wind project, but even with the 10-week delay in the review ordered by the state's Public Service Commission, the developer still expects the project to come into service by the end of 2024.

"We continue to have a target filing date on our COP for Sunrise Wind with BOEM in the second half of this year," Lembo said. "That timetable may be affected by New York's current restrictions on both onshore and offshore survey work. We expect to have more insight into the timing of that cost filing and the schedule for Sunrise by late this summer."

Eversource expects South Fork to come into service by the end of 2022, and Revolution Wind by end-2023, he said.

"Despite these near-term scheduling headwinds, we remain strongly convinced that the opportunities in offshore wind off the Northeast coast are excellent, with 15,000 MW likely to be built over the coming years to supply the significant clean energy needs of New England and New York," Lembo said. ■

*Call transcript courtesy of Seeking Alpha.*

## Company News

# Con Ed Q1 Earnings down on Virus, Weather

*By Michael Kuser*

Consolidated Edison's profits fell nearly 12% in the first quarter, with the utility attributing the decline to the effects of the economic shutdown and unusually warm weather in New York.

The company on Thursday *reported* net income of $375 million ($1.13/share), compared to $424 million ($1.39/share) during the same period in 2019.

During a call with analysts, CEO John McAvoy pointed to the direct impact of the COVID-19 outbreak on the region the utility serves.

"During this pandemic, all of us at Con Edison remain solely focused on the health and safety of our employees and our customers while continuing to provide the highest level of reliable service," CEO John McAvoy said.

"Like many Americans, we have lost family, friends and colleagues to this virus," McAvoy said. "Throughout, I am immensely proud of our dedicated workforce who have risen to the challenge and to our unions' leadership in working with us. We must and will summon all the compassion, grace and strength needed to provide for the recovery."

The company's earnings forecast assumes the restart of some paused commercial activities by early June, with a phased process that continues through the third quarter.

### C&I Volume and Revenue Drop

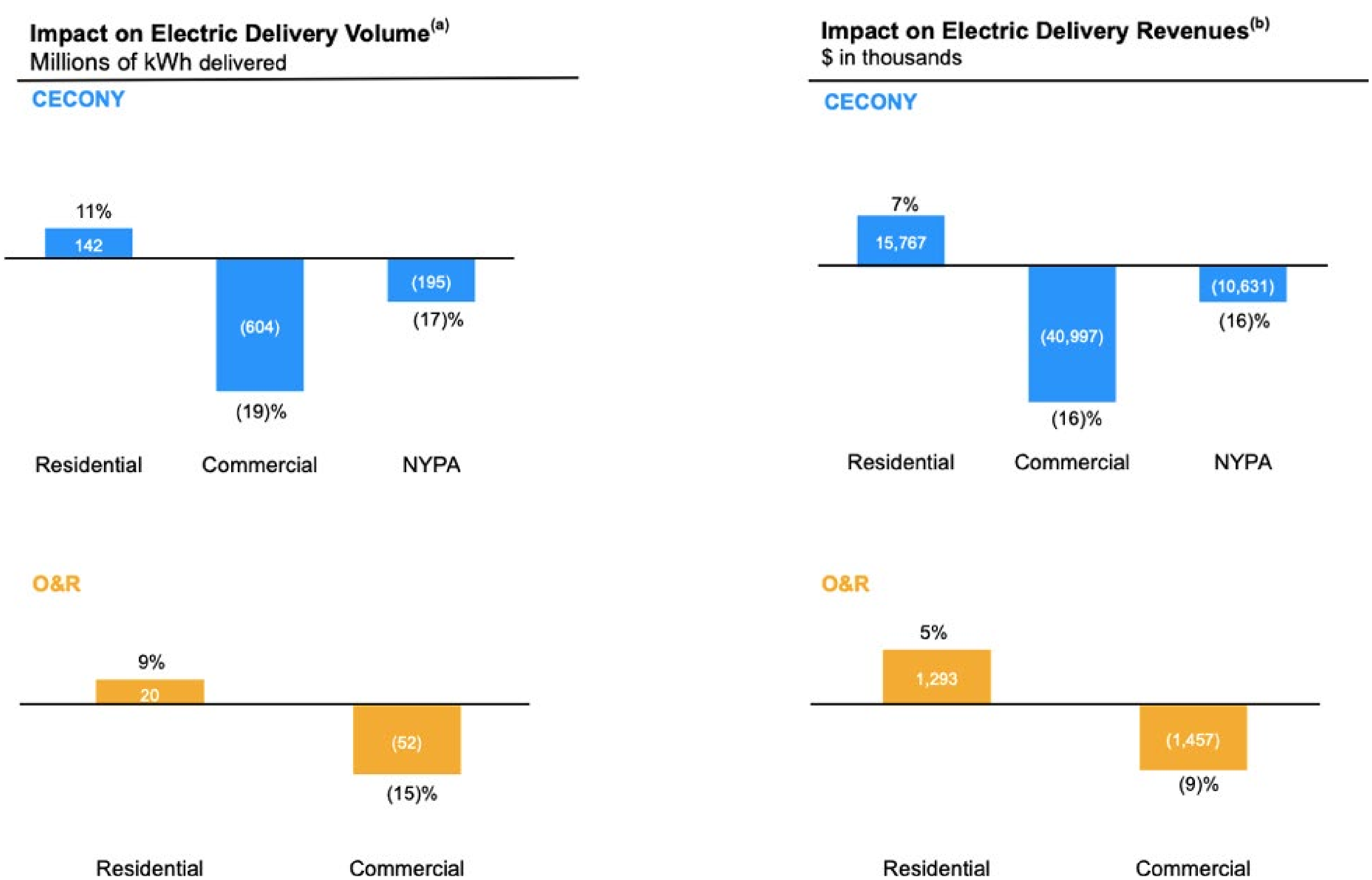
Con Ed mobilized a pandemic planning team in January and an incident command system structure on March 16, the company said in its earnings *presentation*.

With approximately 8,000 of its 14,000 employees working from home or remotely, Con Ed illustrates the truth of recent analysis that predicts the economic fallout from the pandemic will weigh most heavily on utilities most dependent on commercial and industrial load. (See *Researchers: Pandemic to Sting C&I-dependent Utilities*.)

The company's main revenue driver, Consolidated Edison Company of New York (CECONY), showed electric delivery volume for March 16 to April 30 down 19% in the commercial segment and 17% in the industrial segment. Revenues in both categories in the same period were each down 16%.

CECONY residential electricity deliveries were up 11% in the period to April 30 and revenues up 7%.

Con Ed is supporting the community in various ways during the pandemic. It deployed a 1-MW generator to support the field hospital set up at the Brooklyn Cruise Terminal in Red Hook, and expanded grid service or provided engineering services for other emergency field hospitals throughout the city and Westchester County. The company also is making 40,000 face shields in its machine shop for health care workers. ■




Estimated non-weather impact on CECONY electric delivery volume and revenues for March 16 to April 30 | *Con Edison*

## Company News

# Dominion Energy Earnings Impacted by Weather, not COVID-19

By Michael Yoder

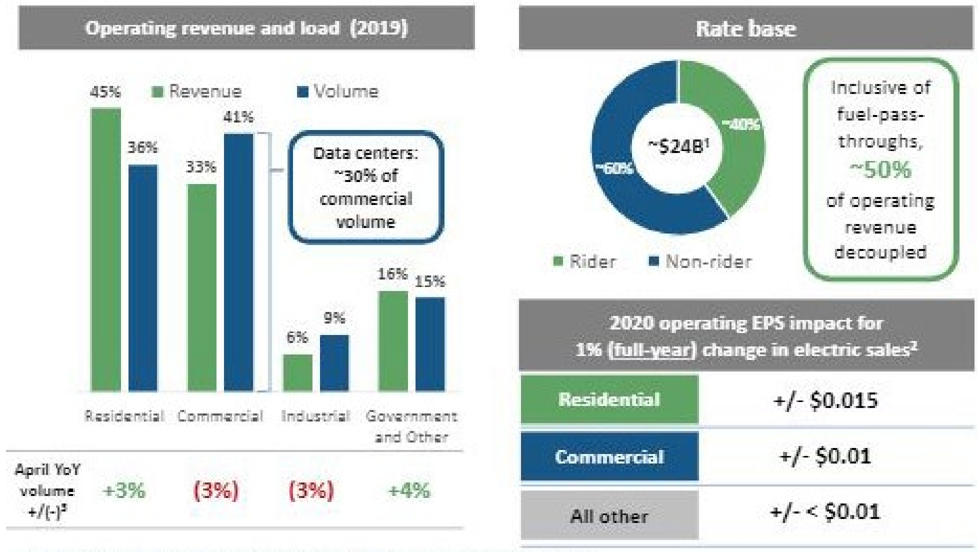
Dominion Energy saw little load impact from the COVID-19 pandemic in the first quarter, company officials said last week, but earnings were hurt by an abnormally warm winter season.

The company on May 5 *reported* a $270 million ($0.34/share) net loss compared with a $680 million net loss ($0.86/share) in the first quarter of 2019.

CFO Jim Chapman said unfavorable weather conditions impacted utility earnings by 9 cents as Virginia recorded its third warmest first quarter on record. The first quarter marked Dominion's 17th straight quarter of delivering results within the company's guidance range, which was set at between $1.05 and $1.25/share.

Dominion is initiating a second-quarter operating earnings guidance with a range of 75 cents to 85 cents/share, Chapman said, while affirming the annual guidance range of $4.25 to $4.60/share. The second-quarter and full-year guidance ranges reflect preliminary expectations for the impacts of the pandemic.

Dominion officials are assuming that the U.S. economy will begin to ramp up through late summer, and Chapman said electricity demand in Virginia has remained positive in relation to recent years despite the pandemic.




| Dominion Energy

"Virginia load is continuing to prove extremely resilient," he said, attributing the resilience to several factors.

Residential usage within Dominion Energy Virginia (DEV), which typically accounts for around 45% of revenue, increased in year-over-year volume by about 3% in April as more individuals worked from home.

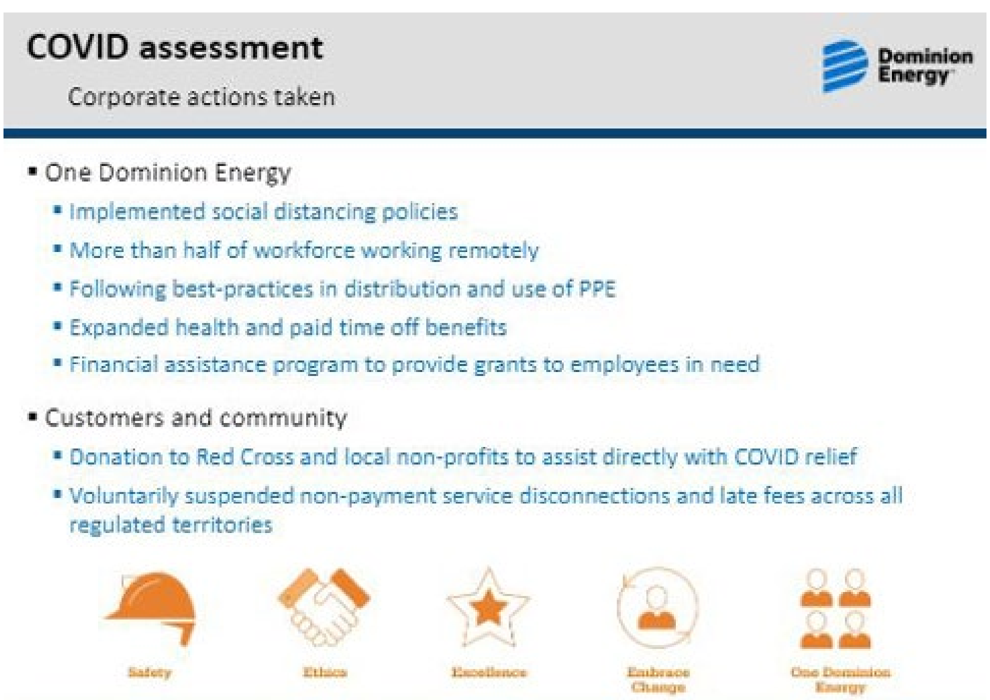
Despite the stay-at-home order in Virginia, Chapman said commercial load decreased by only 3% in year-over-year volume as losses from shuttered businesses were offset by the "proliferation of data centers in our service territory," which has accounted for 30% of commercial volume since 2019.

A limited industrial exposure within Dominion's Virginia footprint also kept load impacts from being severely impacted, he said, with only 6% of DEV's revenue attributable to industrial usage.

Finally, government and military electricity usage, which accounts for 16% of revenue and 15% of volume, was up almost 4% year-over-year in April.

"Based on observable data, we're not at present forecasting major COVID-driven revenue impacts associated with reduced load at Dominion Energy Virginia during the remainder of 2020," Chapman said. "Of course, the situation is dynamic."

CEO Thomas Farrell said the company has taken steps to help customers struggling in the uncertain economy created by closures because of the pandemic, including voluntarily suspending nonpayment service disconnections and waiving late fees across all utility service territories.




| Dominion Energy

# Company News

The COVID-19 response within the company has involved utilizing frequently drilled crisis response plans, he said, as well as the activation of its remote connection infrastructure, which is enabling more than half of Dominion's workforce to operate remotely.

Farrell said Dominion has been fortunate that, among its 19,000 employees in 20 states of operation, "very few" workers have tested positive for COVID-19. Most of the positive cases are asymptomatic or mildly symptomatic, and most of them have already returned to work.

## A Renewable Future

The proliferation of renewable energy resources within Dominion also played an important part of last week's conference call. The company filed its 15-year *long-term integrated resource plan* for Virginia on May 1. The IRP includes plans to increase solar, wind and energy storage capacity, with some increases coming from mandates in recent clean energy legislation signed into law in April by Gov. Ralph Northam. (See *Va. 1st Southern State with 100% Clean Energy Target*.)

Dominion's long-term IRP also includes:

- more than 5,000 MW of offshore wind planned by 2035, including the 2,600-MW Coastal Virginia Offshore Wind project that has a targeted in-service date of late 2026;
- an increase of its solar fleet, already the fourth-largest among U.S. utility holding companies, to develop and procure approximately 16,000 MW in the state over the next 15 years; and
- expanding energy storage capacity to about 2,700 MW through battery storage pilot programs already approved and scheduled to be online in Virginia in 2021.

Farrell said the proliferation of renewable and intermittent resources across Dominion's system will require continued investment in transmission infrastructure, especially as solar and wind emerge around the state.

Farrell said the Virginia State Corporation Commission's pointed March 26 *decision* denying certain elements of smart meter technology proposed by Dominion because of projected costs was a blow to the company.

The commission estimated that Dominion's proposal, if approved in full, would have cost customers nearly $7 billion over 10 years. Smart meter technology was one of the most expensive elements of the plan, coming in at $752 million in total costs.

Renewables "will require an increasingly modern grid, which is why the recent [Virginia] commission decision to reject certain, although certainly not all, aspects of our most recent grid transformation filing was disappointing for our company and particularly for our customers," Farrell said. ■

## Company News

# PPL Reaffirms 2020 Financial Targets Despite Pandemic

*By Michael Yoder*

PPL remains optimistic it will meet its 2020 financial targets even with the full impacts of the COVID-19 pandemic still unknown, executives reassured investors in a *first-quarter earnings* call Friday.

Bill Spence, in his final earnings call as CEO before he steps down on June 1, said PPL's response to the pandemic has kept it in a "strong position in the face of this challenge." He cited the company's liquidity and steps taken during the first quarter to strengthen its financial position by accessing capital markets.

PPL has not changed its 2020 forecast of $2.40 to $2.60/share, Spence said, despite much of the company's service areas being on lockdown for the past six weeks. Spence said the lockdowns have resulted in lower commercial and industrial load and higher residential loads in all its territories.

"At this point, it is too early to predict clearly what the pandemic impact will be on full-year results," Spence said. "This will depend on how long the pandemic lasts, the pace and extent of the economic recovery and the degree companies continue to employ work-from-home protocols, which is what's driving the higher residential loads."

### Q1 Earnings

PPL's first-quarter net income came in at $554 million ($0.72/share), a 19% jump over the $466 million ($0.64/share) during the same period last year. The company said its per-share earnings rose to 72 cents, compared with 64 cents in the first quarter of 2019.

Adjusted for nonrecurring gains, company officials said earnings were $514 million ($0.67/share), compared to $508 million ($0.70/share) last year. Operating revenue was $2.05 billion, down from almost $2.08 billion last year.

CFO Joe Bergstein said the adjusted earnings decrease was primarily because of a warmer-than-normal winter in the U.S. He said the warm winter drove a -3-cent variance compared to 2019 and about a 5-cent variance in the company's forecast, as heating degree days were down by about 30% in Pennsylvania and 15% in Kentucky compared to normal weather conditions.

Based on observations in April, Bergstein said commercial and industrial load was down 15 to 25% depending on the region. He said those declines were partially offset by higher residential demand, with 1 to 3% increases in its U.K. operations and 5 to 8% increases domestically.

Bergstein also noted losses in the company's U.K. business, with its regulated segment earning 39 cents/share, a 2-cent decrease compared to 2019. Bergstein said decreased U.K. earnings were attributable to lower pension income and higher operation and maintenance expenses.

Bergstein said PPL remains "very well situated" to survive the pandemic, with about $5 billion in total available liquidity. He said during March and April, the company was able to secure term loan facilities of $400 million for 12-and 24-month durations and also issued $1 billion of senior notes.

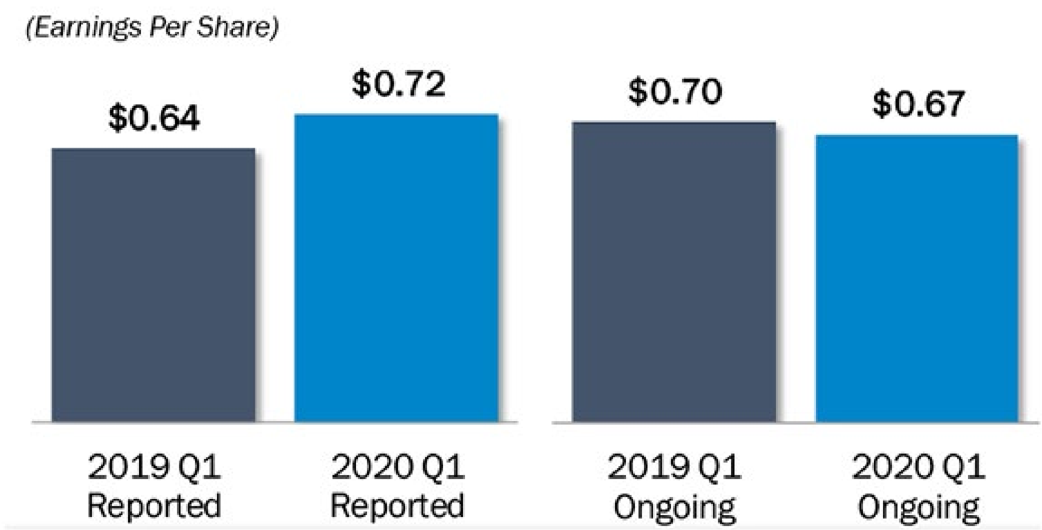
"We believe these positions have the company very well positioned from a liquidity perspective for the remainder of 2020," Bergstein said. "While we have $700 million of additional debt maturities, at the operating companies in November, we believe we'll have the ability to access the capital markets to refinance that debt."

### COVID-19 Response

The background of the pandemic flavored much of the earnings call.

PPL President Vince Sorgi, the person tapped to take over as CEO after Spence's retirement, said the company has taken several measures to keep employees safe from the pandemic, including temperature testing, requiring masks and gloves, and enhancing its industrial cleaning. Sorgi said critical employees, which are primarily control room operators, have been split into multiple teams, and as much as 40% of its total workforce is working from home.

"While we are certainly managing the current crisis at hand and ensuring that our customers and employees are protected during these difficult times, I want to further emphasize that we remain focused on the long-term strategy of the company," Sorgi said. "For PPL and many utilities, that includes the transition to cleaner energy, and we continue to position our utilities to fight climate change in a manner that balances the needs of our customers and the environment." ■




PPL Q1 Earnings | *PPL*

## Company News

# Enable Losses Slam CenterPoint, OGE Energy

### *Houston Utility Takes $1.2B Quarterly Earnings Hit*

CenterPoint Energy on Thursday said it wrote off $1.6 billion in asset losses from its Enable Midstream Partners oil and gas pipeline and storage investment, *resulting* in a $1.2 billion loss (-$2.44/share) for the first quarter.

A year ago, CenterPoint reported first-quarter earnings of $140 million ($0.28/share). Last quarter's revenue of $2.2 billion was similar to the same period a year earlier.

The Houston-based company took the impairment in Enable following the partnership's *recent cutbacks* in the face of economic headwinds. Pummeled by the global slump in petroleum demand and the COVID-19 pandemic, Enable halved its quarterly distributions to investors and cut its capital expenditures for 2020 by $115 million, among other cost reductions.

CenterPoint has a 53.7% limited partner ownership interest in Enable and is expected to take a $115 million hit from the move on an annualized basis.

"We thought that was the right level [for distribution cuts]," interim CEO John Somerhalder said during a conference call with investors. "We're confident in Enable's ability to weather the downturn."

Still, CenterPoint is *taking other actions* to "fortify its financial position," announcing:

- A $1.4 billion equity investment that will eliminate all anticipated equity needs through 2022 and fund a "robust" $13 billion investment program.
- The appointment of former Halliburton CEO David Lesar and Barry Smitherman, who has chaired the Texas Public Utility Commission and the Railroad Commission of Texas, to the company's board.
- The creation of a new Business Review and Evaluation Committee, chaired by Lesar and reporting to the board. The committee will conduct a comprehensive, five-month review of CenterPoint and its businesses.

Somerhalder said the equity investment, combined with the recent *$850 million sale* of a pipeline business and the pending *$400 million sale* of its Energy Services natural gas retail business, will be used to deleverage CenterPoint's balance sheet and the overall credit profile.

"These equity investments provided a transformational opportunity for the company to operate from a position of heightened strength and flexibility," Somerhalder said.

Oklahoma Gas & Electric helped make up for OGE's loss from Enable Midstream. | *OGE Energy*

CenterPoint is also working with regulators across its diverse footprint to address the recovery of COVID-19 expenses. Nearly 70% of its regulated jurisdiction has recovery mechanisms in place, the company said.

The utility's share price outperformed the market Thursday by closing at $17.81, an 11.45% gain from Wednesday's close. CenterPoint stock hasn't seen that level since early April.

### OGE Energy Takes $492M Loss

Enable's distribution cuts also led to a quarterly loss for its other major investor, OGE Energy, holder of a 25.5% limited partner interest and a 50% general partner interest.

OGE took a $780 million impairment in *reporting* a loss of $492 million (-2.46/share) for the quarter. A year ago, the company reported a $47 million ($0.24/share).

"While the Enable write-down was impactful to earnings this quarter, it was not a reflection of the cash flows generated by those assets," CEO Sean Trauschke said. OGE still recorded a cash distribution of $37 million from the partnership, compared to $35 million in 2019.

The company revised its year-end earnings guidance from $2.19 to $2.31 per average diluted share to a net loss of -87 to -77 cents/share.

OGE's share price gained 4 cents during the day, closing at $29.29. The company's stock has lost almost 34% of its value since the year began, when it was $44.06/share.

### Xcel Energy 3 Cents Shy of Earnings Expectations

Xcel Energy *reported* first-quarter earnings of $295 million ($0.56/share), falling short of 2019's first-quarter performance of $315 million in profits ($0.61/share) and analysts' expectations of 59 cents/share.

The Minneapolis-based company said the pandemic did not significantly affect the results, laying the blame instead on the negative impact of weather. Retail electricity sales were only down 1% in the quarter, the company said.

Preliminary sales revenue for April indicates a 9.6% drop, with commercial and industrial sales experiencing a 13.7% fall.

"We are responding to the economic impact from this global pandemic by implementing contingency plans to minimize the impact on our financial results," CEO Ben Fowke said in a statement. "However, these are unprecedented times, and the ultimate economic impact from the pandemic may be greater than anticipated."

Xcel plans to cut operating and maintenance expenses by as much as 5% and institute a hiring freeze.

Xcel reaffirmed its 2020 earnings-per-share guidance of $2.73 to $2.83/share, based on assumptions of a "severe" pandemic-related impacts in the second quarter with a slow economic recovery and a 4% loss in sales over last year. It still cautioned that such a scenario could undercut earnings by 17 cents/share.

"We expect to be a part of the solution to get the economy back on its feet … but this is a fluid situation," Fowke told analysts during Xcel's earnings conference call.

Xcel's share price jumped to $62.06 after the market's open Thursday, following a close the day before of $61.22. After the earnings call, the stock price slid to a close of $59.96. ■

*— Tom Kleckner*

A significant drop in Enable Midstream Partners' unit market price led to huge quarterly losses for investment partners CenterPoint Energy and OGE Energy. | *Enable Midstream Partners*

# Company Briefs

## AEP Names Senior VP, Chief Information and Technology Officer

American Electric Power last week named **Therace Risch** as chief information and technology officer, effective yesterday.

Risch, 47, was most recently executive vice president and chief information officer for J.C. Penney, where she was responsible for strategic direction and tactical execution of the company's information teams and technology systems. At AEP, she will lead technology initiatives across the company, including information technology, innovation, digital initiatives and telecommunications.

More: *AEP*

## Creditors Say Murray Energy Execs Saw Ailing Company as 'Piggy Bank'

A committee of unsecured creditors last week asked the U.S. Bankruptcy Court for the Southern District of Ohio for authority to prosecute claims against Murray Energy founder Robert Murray and CEO Robert Moore.

The creditors allege that between 2016 and 2019, Murray and Moore were paid at least $70 million and potentially as much as $100 million in excessive compensation based on an analysis of their peers. On the day the company filed for a bankruptcy, Murray's base cash salary as chairman of the board was $12 million, an amount 33 times higher than the average of chairpersons at comparable coal companies.

They also say Murray redirected substantial cash to organizations affiliated with the company or in which the family held prominent roles and documented more than $9.8 million in such donations between 2016 and 2019, a time when Murray Energy and affiliates were allegedly "insolvent or spiraling towards bankruptcy."

More: *S&P Global Market Intelligence*

## EPSA Names New Chair of Board of Directors

The Electric Power Supply Association announced last week that it elected Vistra Energy President and CEO **Curt Morgan** as the new chair of its board of directors.

The election took place at the board's annual spring meeting on April 28. Morgan will hold the position for one year.

Thad Hill, the president and CEO of Calpine, will assume the role of vice chair, which was previously held by Morgan. Mark Sudbey, the CEO of Eastern Generation, will continue as secretary-treasurer.

More: *EPSA*

## Great River Energy to Close Coal Plant

Great River Energy last week announced it aims to close its Coal Creek coal plant in North Dakota in the second half of 2022 — several years before it was slated to do so. The company said it will be replaced with new wind farms, including four in Minnesota.

With the plant's shutdown, Great River is likely to be a leading U.S. renewable power supplier, at least in terms of share of total electricity generated by wind. When the transformation is complete, the company expects two-thirds of its electricity will come from wind turbines. The rest will come through purchases in the regional wholesale market.

More: *Star Tribune*

## NiSource Reports Profit, Updates NIPSCO Plans

NiSource last week reported first-quarter net income of $61.8 million, lower than the $205.1 million reported in the first quarter of 2019.

The company said the results include a loss of $280.2 million from shifting its Columbia Gas of Massachusetts assets to a "held for sale" accounting classification. It is selling the company to Eversource Energy as part of a settlement stemming from the natural gas explosions in Massachusetts' Merrimack Valley in 2018. It expects the sale to close by the end of the third quarter.

NiSource also updated investors about Northern Indiana Public Service Co., which has entered several agreements for wind energy and is in discussions to replace nearly 80% of its remaining coal-fired generation by 2023 and 100% by 2028. Construction is underway on two wind projects — Rosewater and Jordan Creek — which are expected to be in service by the end of the year.

More: *The Times of Northwest Indiana*

## Sempra Delays Texas LNG Project

Sempra Energy last week said it was delaying a decision to move forward with a large LNG export project in Texas until 2021 because of the COVID-19 pandemic cutting global demand for energy.

The company said that it had been targeting a final investment decision on the proposed Port Arthur LNG export plant in the third quarter. It is in talks with units of Saudi Aramco to buy 5 MTPA of LNG and invest 25% equity, and with Polish Oil & Gas Co to buy 2 MTPA.

Sempra's Costa Azul LNG export plant in Mexico is still slated to move forward. The company said it expects to make a final investment decision in the second quarter.

More: *Reuters*

## Siemens Gamesa Says Coronavirus Will Squeeze 2020 Finances

Siemens Gamesa last week said project delays and supply chain disruptions caused by the COVID-19 outbreak would continue to pull down its earnings after it squeezed the company's profitability in the second quarter.

The company's margin on earnings before interest and tax shrank to 1.5% for the January-March period while its bottom line turned to a net loss in the quarter. Siemens also withdrew its guidance in April.

More: *Reuters*

## Sunrun Sees Online Solar Sales Bump Following Initial Slump

Sunrun's quarterly installations grew 13% year-over-year to 97 MW in the first quarter with COVID-19 restrictions only impacting the last few weeks of March.

When the pandemic prompted social distancing orders, Sunrun revoked its business guidance for the rest of the year, switched all sales to online and launched solar leases to $1/month for the first six months of its contract. By the end of March, sales were down 40% compared to pre-virus levels. But after switching to online operations, sales increased weekly and grew to rival or beat pre-crisis levels. It culminated in the company hitting its all-time high for single-day orders in late April.

The company said installations are still on hold in New York state and Boston because of local rules, while others are held up by permitting and inspection delays.

More: *GreenTech Media*

### Williams Lands Pipeline Deal with Chevron, Total

Oklahoma pipeline operator Williams last week announced it has reached a deal to transport natural gas from an offshore project being developed by Chevron and Total in the Gulf of Mexico. Financial terms were not disclosed.

Williams will develop an underwater pipeline to move natural gas from Chevron and Total's deepwater Anchor project about 140 miles off the coast of Louisiana and connect to the Discovery System, which is a 477-mile network of underwater pipelines that feed a pair of natural gas and natural gas liquids processing plants.

The Anchor project is expected to come online by 2024.

More: *Houston Chronicle*

### Garland P&L Extends Units' Seasonal Operations

Garland Power & Light last week notified ERCOT that it will extend the operating period of two aging gas-fired units this summer, expanding the availability of 118 MW of capacity for the season. The utility told the grid operator on May 5 that it plans to change the start-up date for the two Spencer Power Plant units from June 1 to May 20 and extend their end date from Sept. 30 to Oct. 10.

Garland's notification of change of generation resource designation filing with ERCOT gives the utility an extra three weeks to take advantage of potential scarcity events this summer. The Texas grid operator again expects record electricity usage and tight reserves. (See *ERCOT Sees Summer Repeat: Record Peak, Tight Reserves*.)

ERCOT currently has a 10.6% reserve margin, but that number will be updated this Wednesday when it releases its final resource adequacy report for the summer. Spencer Units 4 and 5 date back to 1966 and 1973, respectively.

### FERC Sides with Tri-State in Dispute with Ark. River

FERC on Friday accepted Tri-State Generation and Transmission Association's network integration transmission service agreement (NITSA) and network operating agreement (NOA) with Arkansas River Power Authority over the latter's objections. The new agreements replace a NITSA and NOA that expired at the end of 2019.

Tri-State and Arkansas River agreed to all the terms in the new NITSA except for the exclusion of a self-supply option for reactive supply and voltage control. Tri-State said Arkansas River is unable to support the reactive requirements across the transmission system. Tri-State and Arkansas River also disagreed on several terms of the NOA, including balancing authority area (BAA) requirements, operating requirements, load shedding, and load shedding equipment and metering.

The commission was unmoved by Arkansas River's arguments, finding the agreements just and reasonable and making them effective Feb. 25.

More: *ER20-932, ER20-728*

### FERC Issues Tolling Order on El Paso Rehearing Bid

FERC on Friday issued a tolling order giving it more time to respond to Public Citizen's request for rehearing of the commission's conditional approval of JPMorgan Chase's acquisition of EL Paso Electric.

Public Citizen on April 29 asked FERC to reconsider its ruling involving JPMorgan and its financial affiliates it is using to fund its $4.3 billion purchase of EPE. (See *Public Citizen Seeks Rehearing of El Paso Electric Order*.)

"They may make a decision on my rehearing request weeks from now, months from now or years from now," said Tyson Slocum, Public Citizen's energy program director. Given the lack of immediate action, Slocum said he is continuing to press the affiliation issue in other JPMorgan dockets.

More: *EC19-120*

# Federal Briefs

### Coal Snags $31M in Stimulus Loans

The Small Business Administration gave out more than $31 million in loans from the Paycheck Protection Program (PPP), which provided stimulus loans meant to help small businesses hurt by the COVID-19 pandemic, to publicly traded coal mining companies, according to Securities and Exchange Commission filings. Among the recipients were Ramaco Resources, Rhino Resource Partners, Hallador Energy and American Resources.

The funding came after the industry lobbied the Trump administration to add the sector to its list of essential industries after being left off the original version, arguing coal was "critical to supporting hospitals, health care providers and others on the front line."

The mining industry was included in the first $349 billion installment of the program at a higher rate than other industries, as approved PPP loans covered more than 78% of the industry's eligible payroll compared to an average of 54% for all industries.

More: *Bloomberg Green*

### 4 FERC Staff Members Test Positive for COVID-19

FERC announced last week that four of its contract support staff who work at the commission's headquarters building in D.C. have been diagnosed with COVID-19.

The commission said the risk to the limited number of staff who have been in the building is low, as most employees and contractors have been teleworking since March 16. The building remains closed to the public and is now closed to all FERC staff and contractors until further notice.

More: *FERC*

### FERC Provides Accounting Guidance to Ease Administrative Burdens

FERC's Division of Audits and Accounting last week issued an accounting guidance letter to help reduce the regulatory burden and support the industry's COVID-19 pandemic response efforts.

The Financial Accounting Standard Board's

Accounting Standards Update No. 2016-13 requires companies to change the method of measuring credit losses, including uncollectible accounts receivable, from an incurred loss basis to a current expected credit loss basis. The letter said this is a reasonable methodology and is acceptable for commission financial accounting and reporting purposes.

Furthermore, to the extent an entity determines a cumulative adjustment to its beginning retained earnings account is necessary related to the update, the entity is authorized to do so without seeking commission approval, it said.

More: *FERC*

### Legislation Aims to Block Fossil Fuel Companies from Receiving Aid

A group of more than 40 lawmakers last week backed the Resources for Workforce Investments, Not Drilling (ReWIND) Act, which aims to prevent fossil fuel companies from receiving loans from previous COVID-19 aid packages and stop the Trump administration from helping the companies in other ways.

"It would be unconscionable to bail out big oil and gas corporations with money intended to help families, workers and small businesses survive this global pandemic," Rep. Nanette Barragán (D-Calif.) said.

The legislation, which is likely to face resistance in the Senate, includes provisions such as capping the Strategic Petroleum Reserve at its current level of 714.5 million barrels and preventing private companies from storing oil in the reserve, as well as halting the sale of new fossil fuel leases while the administration continues to sell leases on federal land.

More: *The Hill*

### Nuclear Waste Site Delayed amid COVID-19; Public Comment Extended

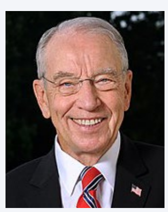
The Nuclear Regulatory Commission last week agreed to extend the public comment period for the licensing of Holtec International's proposed repository of spent nuclear fuel near Carlsbad, N.M., for 60 days amid the COVID-19 pandemic to provide more leeway for those wishing to submit comments.

The state's congressional delegation requested the extension, which is intended to allow the submission of more comments for the draft environmental impact statement issued by NRC for the proposed facility. The delegation expects to continue working with the commission to develop schedules for public hearings throughout the licensing process to ensure interested stakeholders could participate.

The public comment period, which was originally scheduled to end on May 22, is now slated to close on July 22. NRC said it planned to hold a nationwide webinar on the project and would accept written comments through the deadline.

More: *Carlsbad Current-Argus*

### Treasury to Tweak Tax Credit Deadlines for Renewables Projects



The Treasury Department last week sent a letter to Sen. **Charles Grassley** (R-Iowa) in regards to extending deadlines for solar and wind developers looking to qualify projects for the investment and production tax credits, saying it "plans to modify the relevant rules in the near future."

Under existing provisions, solar developers must begin construction or invest a certain amount of cash by a specific date to qualify. Wind developers had to finish construction by the end of 2020 to secure full credit. The timelines of both put pressure on developers who were thrown off as the COVID-19 pandemic began shutting down states.

The full impact of the changes will become clear when the Treasury fleshes out the changes to come.

More: *GreenTech Media*

### US Renewable Sources Top Coal for 40 Straight Days

Electricity generated by renewable sources exceeded coal-fired power in the U.S. for a record 40 straight days (March 25 through May 3), according to an Institute for Energy Economics and Financial Analysis report released last week. The stretch accounted for about a fifth of the grid's power.

The previous longest back-to-back stretch was nine days in 2019. In total, renewables beat coal for a total of 38 days last year.

IEEFA said the boost for renewables is because of a seasonal increase in low-cost solar and hydropower generation, along with an overall slump in demand caused by coronavirus-related stay-at-home orders. Coal tends to be the first source to be cut by utilities when demand falls because subsidized renewable sources are cheaper to operate.

More: *Reuters*

# State Briefs

## CALIFORNIA

### SCE Awards Battery Contracts to Help Replace Aging Natural Gas Plants

Southern California Edison has awarded 770 MW of battery storage contracts that it says will help solve reliability issues that are anticipated to impact the state grid when a number of aging natural gas power plants reach their retirement.

NextEra Energy secured three of the seven bids totaling 460 MW. Southern Power won two (160 MW total), while LS Power (100 MW) and TerraGen Power (50 MW) took one each. Contract lengths range between 10 and 20 years, with most lasting 15. The projects still require Public Utilities Commission approval and are to be submitted later this month.

While roughly 3 GW of natural gas plants scheduled for retirement by the end of this year have been given extensions, the PUC determined that 3,300 MW of "system-level resource adequacy capacity" needs to start coming online incrementally. Load-serving entities and other investor-owned utilities are responsible for bringing them online.

More: *Energy Storage News*

## COLORADO

### Pueblo Votes to Keep Black Hills Energy

Pueblo residents last week voted to keep Black Hills Energy as the city's electricity provider for at least the next five years after they rejected a ballot question that would have asked the public if it wanted to leave the company and form a public electric utility with the Board of Water Works at the helm.

Although there were still thousands of ballots left to count as of last Tuesday, the current margin (12,727 against and 5,930 for) is overwhelmingly in favor of keeping Black Hills.

While the agreement is for 10 years, the City Council can opt out of the pact in 2025 if it chooses to.

More: *KXRM*

## ILLINOIS

### Attorney General Sues Developer, Contractors in Coal Plant Implosion

The attorney general's office last week filed a lawsuit in Cook County Circuit Court against developer Hilco Redevelopment Partners and its general contractors, MCM Management and Controlled Demolition, for violating state law and Pollution Control Board regulations when contaminants were released during the implosion of a 378-foot smokestack at a defunct Chicago power station on April 11.

The botched implosion sparked outrage among residents of the Little Village neighborhood. Because of the neighborhood's high number of low-income and minority residents, the area is designated by the state Environmental Protection Agency for environmental justice concern.

The station being demolished was a coal-fired plant, causing concern that the neighborhood was contaminated with asbestos and other particulate matter and pollutants. However, early air quality testing found no asbestos and said levels of particulate matter have not exceeded standards for the area.

More: *The Associated Press*

## IOWA

### Golden Plains Wind Farm Becomes Operational

Alliant Energy and EDF Renewables' 200-MW Golden Plains project has achieved commercial operation in Winnebago and Kossuth counties.

The farm, which was developed and constructed by EDF, utilizes 82 General Electric wind turbines. The company has developed or placed in service 1.4 GW of wind energy in the state, while Alliant expects to own and operate nearly 1.3 GW of that generation.

More: *North American Windpower*

## MICHIGAN

### PSC Reduces DTE's Rate Hike

The Public Service Commission last week approved a rate increase for DTE Energy, but it was for $188 million as compared to the $351 million the company had requested. The increase will amount to about $4/month more for a typical residential customer.

The PSC expressed concerns about DTE's plans to spend more on coal-burning power plants and several other issues, while Commissioner Daniel Scripps took it a step further and admonished the company for not spending properly on maintenance and infrastructure.

"We expect that any dollars authorized to improve reliability will be spent to improve reliability. And we will continue to focus on ensuring accountability in this regard," Scripps said.

More: *Michigan Radio*

## NEW JERSEY

### Audit Finds ACE Sought Repeated Rate Increases to Make up for Shortfall

Atlantic City Electric (ACE) sought frequent rate increases between 2009 and 2017 to compensate for under-earnings that totaled $285 million, according to an audit released last week by the Liberty Consulting Group on behalf of the Board of Public Utilities. As a result, the utility filed four rate cases between 2015 and 2017 that resulted in $126.5 million in increases in customers' bills.

The nearly 700-page audit found that ACE was making far less than their authorized rate of return over that period. In fact, the audit noted the utility earned less than a 5% return on equity in each year from 2011 to 2017. The earnings deficiency averaged $28.5 million over the time frame.

The audit blamed the less-than-authorized earnings on two factors: increased spending on operations and maintenance costs ($136 million) and capital expenditures that were not quickly included in rate base ($126 million).

More: *NJ Spotlight*

## OREGON

### Lake County Solar Projects Blocked

The Land Use Board of Appeals last week overturned Lake County's conditional use permits for two solar projects that sit on 640 acres and ordered the local government to reconsider the approvals. At the same time, Obsidian Renewables, the project's developer, is seeking permission from Energy Facility Siting Council to move forward with plans for a 3,921-acre solar project that encompasses the smaller sites.

While smaller projects must win county land use approval under state law, larger proposals must obtain permission from the siting council, which has scheduled a public hearing about the facility on May 21. A group of farmers is protesting the projects, saying that clearing brush will displace rodents onto surrounding farms.

The projects were approved in 2019, but regulations governing the size of solar projects have since changed. Under a law that became effective in 2020, counties may have jurisdiction over solar projects up to 1,920 acres on lower-quality uncultivated ground.

More: *Capital Press*

## WISCONSIN

### We Energies Projects Drop in Electricity, Industrial Sales

We Energies last week said that since Gov. Tony Evers issued his "safer at home" order, the company has seen industrial energy use drop 18% and expects retail sales to fall 5% over the next nine months as the economy begins to recover from the COVID-19 crisis.

WEC Energy Group Chairman Gale Klappa

said shelter-in-place orders had a "minimal impact" on the company's first-quarter earnings, but overall electricity sales have fallen 7% since March 24.

Klappa also does not expect sales to fully recover this year. The industrial segment is expected to see the biggest hit, with sales 18% below forecasts in the second quarter and remaining 7% below by the fourth quarter. Small industrial and commercial sales are expected to fall 8% in the second quarter but improve to just a 3% reduction in the fourth quarter. Residential sales, which are up about 5%, are expected to be up 4% in the second quarter and return to near-normal levels by the end of the year.

More: *Wisconsin State Journal*