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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Assistant to the Publisher
Tri Bui

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 658-6885
See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

FERC/Federal News

EPA Power Plant Proposal Gets Mixed Reception in Comments

Grid Operators Suggest Changes

By James Downing and K Kaufmann

EPA was deluged with comments last week on its proposal to limit greenhouse gas emissions from existing plants, with supporters and opponents urging changes to what the agency produced. (See *EPA Proposes New Emissions Standards for Power Plants*.)

Filing as the "Joint ISOs/RTOs," four organized electricity markets — ERCOT, MISO, PJM and SPP — told EPA that the power plant rule could exacerbate the trend of retirements outpacing the commercialization of new resources needed to produce vital reliability attributes.

"The Joint ISOs/RTOs have long been at the forefront of renewable energy integration but have seen an increasing trend of retirements of dispatchable generation, which provides critical attributes that are needed to support the reliable operation of the grid," the grid operators said. "Although each region is working to facilitate a substantial increase in renewable generation, the challenges and risks to grid reliability associated with a diminishing amount of dispatchable generating capacity could be severely exacerbated if the proposed rule is adopted."

While EPA has created subcategories of dispatchable generation in an attempt to stagger retirements, its rule assumes that new, low-greenhouse gas substitutes will be available, and that existing plants will be able to retrofit with carbon capture and storage (CCS) or co-fire with clean hydrogen. The grid operators said the proposal overstates the commercial viability of CCS and clean hydrogen while ignoring the cost and practicalities of developing new supporting infrastructure.

EPA should do additional analysis and address the potential reliability impacts of its proposal before moving forward with a final rule, the Joint ISO/RTOs said. If EPA decides to go forward, the grid operators suggested that it allow for a new sub-category of existing units, which are needed for local or regional reliability until alternatives are running that address the reliability issues. ISOs and RTOs would identify such units, in a process similar to reliability-must-run agreements.

"To be clear, the reliability sub-category is not a panacea," the Joint ISO/RTOs said. "It still would leave generation owners with considerable uncertainty as they assess the long-term future of market participation."

But the reliability sub-category could keep some generation that would put reliability at risk if it retired too early running while viable alternatives are developed and can be deployed economically and practically, they said.

The agency should also build a regular technology review into the rule to determine whether CCS and hydrogen-fired generation are developing quickly enough to meet compliance timelines, the grid operators argued. That would help balance the pace of retirements with needed replacements, they said.

| Steven Baltakatei Sandoval, CC BY-SA-4.0, via Wikimedia

The rule suggests states could develop allowance trading systems, but the ISO/RTOs said it should provide specific recognition of allowance trading on a regional, if not national level to allow for greater flexibility and to allow units that can "over comply" early to do so (and sell any excess allowances that leads to).

The Joint ISO/RTOs also want a tweak to the proposal's definition of a system emergency, which would apply under "any abnormal system conditions." That "abnormal" is unnecessary because grid operators already have to determine that the generator in question was needed for reliability, they said.

ISO-NE filed its own comments, which noted that while it had lacked the time for a complete analysis of the rule, it believes some of EPA's proposals could actually work against reducing emissions. When it comes to natural gas power plants, the proposal is focused on combined cycle plants above 300 MW that operate more than half the time.

"The resulting effect is a shift in generation from these large EGUs [electric generating units] to the smaller, less efficient EGUs," ISO-NE said.

ISO-NE's modeling assumes all coal generation will be retired by 2032 and the grid will have less generation from large gas plants, which means the grid will rely on active demand response (ADR) much more often than it does now.

"If ADR resources dispatch as often as they are in the results of the ISO's analysis (a large increase from today), some resources may no longer choose to provide ADR," ISO-NE said. "In the absence of ADR, other load in this model would go unserved."

EPA has not released a related rule on how it plans to regulate smaller natural gas plants, and ISO-NE said it was difficult to determine how its system would be impacted without those details.

Broad Opposition to CCS

A diverse array of stakeholders challenged EPA's designation of CCS as a best system of emissions reduction (BSER), arguing the technology has not been "adequately demonstrated," as the proposed rule states.

FERC/Federal News

Representing a consortium of environmental justice and conservation groups, the Clean Energy Group (CEG) argued that carbon capture could increase greenhouse gas emissions. "Because of the additional fuel needed to power CCS equipment itself, electricity generation paired with CCS requires up to 44% more fuel than standalone power generation," it said. Emissions of nitrogen oxides (NO_x) and particulate matter, generally not captured by CCS technology, would also increase.

Leading a group of five other unions, the International Brotherhood of Boilermakers pointed to the $2.5 billion in the Infrastructure Investment and Jobs Act (IIJA) for CCS demonstration projects as clear evidence that the technology is not at commercial scale, nor is likely to be within the time frames the rules suggest.

Power plants with a retirement date of 2040 "would need to begin preparations for a major CCS retrofit project — engineering, financing, permitting and related activities — as soon as possible following a final rulemaking," the unions said.

EPA's requirement that these plants capture and sequester 90% of their CO_2 emissions "itself is objectionable because these units likely differ widely in age, size, capacity factor, access to suitable CO_2 storage capacity, and the technical and economic feasibility of retrofitting CCS."

Other commenters pointed to the lack of adequate pipelines and storage facilities and the lead time needed for buildout.

Mississippi's Office of Pollution Control suggested that the agency's promotion of both CCS and hydrogen were intended to build demand for the technologies as a means to justify the incentives they would receive from the IIJA and the Inflation Reduction Act.

"However, the cost and feasibility of constructing thousands of miles of pipeline to address the CO_2 and hydrogen infrastructure requirements is not contemplated in the proposed rules or regulatory impacts analysis. EPA provides no substantive evaluation of the environmental impacts constructing thousands of miles of additional pipeline will have, including additional air emissions that may be generated from compressor stations required along these pipelines or associated with sequestration and storage facilities."

Even the Carbon Capture Coalition, an industry advocacy group, said that while EPA's time frame for getting CCS projects planned and online is possible, "there are several potential economic and practical delays due to project permitting and financing. EPA should clearly specify what happens when factors outside the owner's control delay construction or operation of a carbon-capture system."

The coalition called for "a cohesive national plan" for CCS buildout.

"We urge EPA to work with states to make available supportive infrastructure and a robust and timely permitting process to deploy carbon-capture technologies not only at individual facilities but in a coordinated regional manner."

EEI Offers to Work with EPA

The Edison Electric Institute said that while its members are committed to cleaning up the grid, with 41 having committed to getting to net-zero emissions by midcentury, some elements of EPA's proposal need to change to get that job done while maintaining reliability.

"While there are challenges presented by the proposed [Clean Air Act Section] 111 rules, these challenges are technical in nature," the investor-owned utility trade group said. "EEI and our member companies share EPA's goals of continuing to reduce emissions from the power sector and of achieving an economy-wide clean energy transition."

Current technologies can support a continued decline in emissions from generation over the foreseeable future, but getting to net zero is going to require the development of technologies that are not commercially feasible today, EEI said. CCS and hydrogen blending have yet to be adequately demonstrated and are not deployable, available or affordable across the entire industry, and they require significant infrastructure outside of the power plants to work, it said.

EEI supports the proposal's use of subcategories, which in the case of coal units are based on their operating horizon or when they plan on retiring, and one of the categories caps plant's capacity factors. Coal plants running past 2040 would need 90% CCS, with declining standards for those that retire earlier. While EEI has some quibbles with those specifics, it noted that EPA's much less flexible approach to large natural gas units is not supported.

"EPA's inflexible, rate-based approach to regulating existing natural gas-based turbines presents significant challenges and is likely to result in perverse outcomes that are inconsistent with EPA's larger emissions-reductions goals," EEI said. "EPA's failure to offer similar compliance flexibilities to existing natural gas-based turbines as those offered to states for existing coal-based units is fundamentally arbitrary."

Gas units provide some of the same key grid services that coal plants do, but they are also more flexible and thus help in balancing intermittent renewable power, EEI said. EPA should develop and provide a full range of flexibilities in compliance for natural gas units, it argued. By the 2030s, such plants will either have to make costly, long-term investments or agree to capacity factor limits that will make them unavailable to help meet growing demand from electrification, which the industry is already experiencing. The power industry would have to turn to less efficient power plants to meet demand, it said.

"Under several plausible scenarios, this could result in an aggregate increase in emissions during the 2030s, at the expense of reliability," EEI said. "This is an outcome that should be avoided by the agency."

EEI noted that it had a limited amount of time to file comments on the rule, and it would continue to update its analysis and keep EPA in the loop on those efforts. EPA should also pay attention to FERC's annual reliability technical conference in November, which the commission *announced* would cover the impact of EPA's proposal.

Other Power Sector Trade Groups More Skeptical

The Electric Power Supply Association (EPSA) told EPA that it should give weight to its comments as its members own and operate power plants and thus are going to be responsible for the costs of implementing any final rule. The trade group said that implementation of the proposal would degrade reliability at a time power demand is growing.

"This proposed rule is intended to reduce emissions," EPSA said. "However, while indirectly boosting investment in renewable energy, the proposal may negatively impact emissions reductions by rewarding less efficient existing power plants and hampering the use of existing lower-emission resources. Further, retirements of existing fossil fuel resources may occur before adequate replacement resources of any/all types are constructed, raising genuine concerns about electric grid reliability in the near and midterm."

While many might dismiss the reliability concerns as voiced by directly impacted generators, EPSA said, FERC, NERC and the ISO/RTOs have made the same kind of arguments. FERC Commissioner Mark Christie recently told the Senate that the industry is headed toward a reliability crisis. (See *Senators Praise Philips, FERC's Output at Oversight Hearing*.)

The lynchpins of compliance in EPA's proposal are co-firing hydrogen and CCS, but those are emerging technologies, the group said.

"As a practical matter, robust CCS/hydrogen co-firing industries will need to be built almost from scratch, and the proposed rule requires those technologies be counted on in an unworkable and unrealistic time frame," EPSA said. "They are not 'adequately demonstrated' by any real-world definition, and it is critical that the fundamental impediments to the technologies given the timelines outlined in the proposal be addressed and mitigated."

The National Rural Electric Cooperative Association (NRECA) told EPA that it should withdraw its proposal, arguing that it exceeds the agency's authority and would jeopardize reliability by requiring the industry to shift too early to technologies that are not commercially viable.

"Under the Clean Air Act, EPA's standards must be adequately demonstrated, achievable and cost effective," NRECA said. "Its proposed best systems of emission reduction in the form of carbon capture and storage, co-firing clean hydrogen or co-firing natural gas all fail to meet these criteria."

CCS has promise, and NRECA members have been involved in deploying it, but it is not ready to capture 90% of the emissions from the nation's coal- and gas-fired power plants, the group argued.

The proposal "is also heavily reliant on outside-the-fence-line infrastructure that does not currently exist and will not exist by the proposed compliance dates," NRECA said. "Clean hydrogen is even further behind CCS in its development. There is currently no supply of clean hydrogen to meet EPA's standards."

NRECA said that even without the proposal, the U.S. is seeing too many power plants retire too early, noting that NERC and ISO/RTOs have raised that concern in recent reports. Federal agencies, including EPA, should be considering how they can avoid exacerbating those risks.

The American Public Power Association made similar arguments, saying that the agency could not rely on hydrogen and CCS under the CAA because they are not commercially viable. EPA needs to analyze the impact of its proposal on electric reliability, as the grid has already started on its transition away from traditional power plants to a growing share of renewables, the group said.

APPA said the impact of retiring fossil-fuel plants can be seen in the number of requests that the Department of Energy has had to process under Section 202(c) of the Federal Power Act, which suspends compliance with environmental rules when a unit needs to do that to maintain reliability. In the first 20 years of the century, DOE issued eight orders under 202(c).

"This number of orders was nearly matched in 2022 alone, when seven such emergency orders were issued, highlighting the urgency of the situation," APPA said. "Since 2020, DOE has issued a total of 11 emergency orders over reliability concerns. This surge in emergency orders underscores the need for EPA to re-evaluate the proposed rule to maintain the reliability of the electric system."

Flexibility Needed

Other commenters said EPA should broaden its definition for BSERs to include renewable energy or other energy-efficient and clean technologies.

The Business Council for Sustainable Energy, an industry organization that includes natural gas companies, recommended a "flexible and technology-inclusive approach" to BSERs. EPA should "recognize and consider recent market trends that include the falling costs and increased deployment of clean energy and energy efficiency. Regulation should provide clear and sustained market signals that spur emissions reductions through investment in the full portfolio of clean energy technologies."

With the electricity sector already moving toward decarbonization, narrow and prescriptive regulations could draw resources away from planned projects and investments, BCSE said. EPA's regulations "should not inhibit compliance with local, state and regional policies or divert investment and/or human capital that has been dedicated to decarbonization goals."

CPS Energy, the municipal utility serving San Antonio, Texas, and its suburbs, also argued that both CCS and hydrogen "might not be easily applied to every fossil generating plant depending on design and location. The rule should allow for flexibility and not lean on specific technology solutions but rather allow each state broad discretion while working with utilities to evaluate measured proposed responses that protect system reliability and resiliency."

Advanced Energy United wrote in support of the proposed rule but presented renewables, demand response and virtual power plants as technologies that also can provide grid

FERC/Federal News

reliability and resilience, undercutting traditional arguments on the need for dispatchable fossil-fueled generation.

"During Winter Storm Uri in 2021, coal and gas plants made up 73% of generation capacity in Texas that experienced 'outages or derates,'" AEU said.

"Fossil-fueled power plants will need to employ costly best systems of emission-reduction technologies in order to meet [EPA] standards. However, renewable energy provides a price-competitive and reliable opportunity to maintain access to affordable power and mitigate grid outages."

Similarly, CEG argued for renewables and energy storage as BSERs, noting that the proposed rule acknowledges that renewables and battery storage would eventually outcompete natural gas, leading to an expected decline in gas-fired generation.

Given that renewables and storage are "readily available, more than adequately demonstrated and reasonable in cost," why is EPA trying to incentivize CCS and hydrogen, technologies that are not mature and "not non-emitting"? CEG asked. "Why isn't the focus instead on developing rules that help accelerate the pace of renewable energy and energy storage displacement of fossil generation?"

Finding themselves potentially on the same side as utilities and fossil fuel companies opposing the rule, environmental groups have been quick to differentiate their concerns and goals from the industry's.

"Utilities oppose regulation; we oppose bad regulation," Monique Harden, of the Deep South Center for Environmental Justice in New Orleans, said during a press call Aug. 8. "We want the EPA to do better, and it can do better."

"Our problem with the rule is that it's not bold enough; the rule doesn't go through that rapid-change transition … to renewable energy and energy efficiency," said Nicky Sheats, director of the Center for the Urban Environment at Kean University in New Jersey. "We want massive change not only in technology, but systemic change also."

'Penalty-free Emissions'

Another subset of commenters supported the rule as a way to cut emissions from coal and natural gas plants but called for accelerated timelines for compliance for more power plants, with a specific focus on the health impacts for disadvantaged and low-income communities.

The nonprofit Wisconsin Environmental Health Network encouraged "the EPA to strengthen and fast-track the improved standards placed on new and existing fossil fuel-fired power plants."

"To maximize the efficacy of these regulations … the EPA [should] apply pollution safeguards to a wider number of power plants across the nation. A [broader] distribution of this action will ensure that fewer communities are subjected to unhealthy levels of pollution and dangerous air quality. This is especially important for socially vulnerable populations, since they are *impacted more severely* from climate change."

Mass General Brigham, a network of hospitals in Boston, also urged that the rules be applied to more power plants "by lowering the threshold for unit size and capacity factor. … As written, the rule only regulates larger power plants [more than 300 MW], which could incentivize plant operators to shift power generation to smaller facilities that emit more pollution and are more likely to be proximal to environmental justice communities."

The group also called for EPA to require new plants to immediately comply with the proposed 90% emission reduction and to move up compliance dates for existing coal and natural gas plants. If opting to "co-fire" with natural gas and hydrogen, existing plants would have until 2032 to comply, while those using CCS would have till 2035.

"The health harms of fossil fuel combustion have long been known," Mass General said. "These delays represent 10 additional years of penalty-free emissions and lost opportunities to accrue additional health benefits." ■

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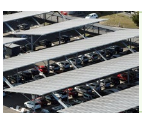

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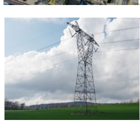

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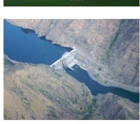

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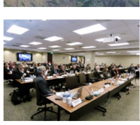

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RTO Insider subscribers have access to two stories each monthly from *NetZero* and *ERO Insider*.

FERC/Federal News

DOE Proposes Streamlined Federal Transmission Permitting

Coordinated Review Process Would Have Two-year Window

By John Cropley

The Department of Energy on Thursday proposed a set of rules to streamline the federal permitting of certain onshore electric transmission projects.

CITAP, the Coordinated Interagency Transmission Authorization and Permits program, would establish a two-year timeline for federal review of transmission proposals. It would set deadlines for permits and authorizations but also seek to ensure local communities, tribes and other stakeholders have an opportunity for engagement, DOE said in a *news release*.

DOE's Grid Deployment Office would administer CITAP and is seeking public comment on the *Notice of Proposed Rulemaking* issued Thursday.

CITAP would be one response to a pressing issue — the lengthy process for adding the infrastructure that is critical to greater electrification of the U.S.

Many clean energy projects proposed nationwide are slowed, stalled or even canceled because of the time and cost of securing interconnection. A 2022 *DOE report* found more than 930 GW of generation and more than 420 GW of storage in transmission queues nationwide.

That will increase as fossil fuels are replaced with electrons. DOE said independent estimates find that transmission capacity will need to increase 60% by 2030 and perhaps triple by 2050.

The CITAP proposal grows from a May 2023 *memorandum of understanding* signed by DOE and eight other federal agencies. DOE draws its authority to lead the process from Section 216(h) of the Energy Policy Act of 2005.

CITAP would not replace state or local permitting, nor would it circumvent any federal laws. Instead, it seeks to streamline the regulatory portion of a process that can extend more than a decade from start to finish.

Under the proposed rulemaking:

- DOE would identify all entities with a role in a given transmission project, lead an iterative process to ensure the developer's applications for federal authorization are ready by the binding timelines to be established and work with relevant agencies to prepare a single environmental review document for use by all of the federal entities with oversight on the project.
- Developers would have to participate in an integrated interagency preapplication process that would provide a uniform mechanism for them to identify constraints and opportunities, gather information, engage with local stakeholders and prepare a plan for public engagement throughout the life of the project.
- And there would be a standard schedule for all of this to unfold — DOE produced a *draft version* as part of the proposal. The schedule would be a template, however, not a rigid timeline. Each proposal would receive a project-specific schedule factoring in location, scope and potential impacts.

A U.S. Department of Energy proposal would streamline the federal permitting of transmission lines. | *Shutterstock*

Reaction

Clean energy industry and advocacy organizations welcomed the proposal, as far as it goes.

"ACEG strongly supports DOE's action to improve coordination and transparency in the federal permitting process," said Christina Hayes, executive director of Americans for a Clean Energy Grid. "Implementing a one-stop-shop for agency reviews and setting strict deadlines for this process will represent a fundamental leap forward from the current system, which requires applicants to juggle each agency's timeline separately and can sometimes delay a project by years. The nation needs more transmission, and we need it as soon as possible to improve electric reliability and lower costs for American households. This rule will get us closer to the finish line."

"ACP appreciates DOE's efforts to streamline the process for permitting transmission lines, and we look forward to reviewing and commenting on the proposed rule," said American Clean Power Association Vice President of Markets & Transmission Carrie Zalewski. "While this is a positive step, it's critical that Congress build upon these actions and tackle comprehensive, meaningful permitting reform that, among other things, improves the permitting process for high-impact transmission lines."

"Transmission developers are facing inefficient and lengthy review processes to getting projects permitted and approved, leading to increased costs and delayed timelines," said Caitlin Marquis, managing director at Advanced Energy United. "Electric transmission lines are the essential backbones of our power grid, and building more transmission leads to lower energy costs and improved grid reliability. A more efficient permitting program that maintains essential review processes will provide more certainty for developers and support a stronger, more resilient power grid." ■

FERC/Federal News

EIA Reports Rising Solar Installation, Oil Production

Domestic Crude Output Expected to Set Record Later in 2023

By John Cropley

Competing pictures of the U.S. energy transition were drawn last week, as federal reports showed soaring solar power output and domestic crude oil production poised to set a record.

In its latest inventory of electric generation capacity, the Energy Information Administration said that 5.9 GW of solar came online in the first half of 2023 and that the figure would have been much higher but for supply chain constraints.

EIA also reported that it expects sustained global demand for petroleum to drive U.S. crude oil production above 12.9 million barrels a day for the first time this year and above 13 million in early 2024.

The solar data were drawn from EIA's preliminary *Monthly Electrical Generator Inventory* for June. The report inventories utility-scale generating facilities, defined as those with a nameplate capacity of 1 MW or greater.

It showed that 5.9 GW of new solar came online in the first six months of 2023, along with 5.7 GW of natural gas-fired generation, 3.2 GW of wind power and 1.8 GW of battery storage.

At the start of 2023, developers and planners reported that they expected to build 10.5 GW of solar in the first half of the year but fell far short of that projection, largely because of shortages or delays in obtaining materials.

Two large gas-burning plants — the 1,836-MW Guernsey Power Station in Ohio and the 1,214-MW CPV Three Rivers Energy Center in Illinois — accounted for more than half the new natural gas nameplate capacity in the first half.

Most of the new battery capacity was in Texas and California; the Moss Landing battery energy storage facility in California became the nation's largest as expansion nearly doubled its capacity to 750 MW.

Delays in construction of battery facilities in the first half were even greater than in solar: 3.1 GW of planned storage construction was pushed back to the second half of the year.

The total 16.8 GW of new capacity in the first half of the year was countered by the retirement of 8.2 GW of existing generation capacity, almost all of it coal and gas. The second half of 2023 is expected to see 35.2 GW added, bringing the totals for the year to 25.2 GW of solar, 9.6 GW of storage, 8.1 GW of wind and 7.8 GW of natural gas.

The second half is also expected to see the continued exit of coal from the U.S. fuel mix. Total coal retirements in 2023 are expected to reach 9.8 GW, or 5% of the existing coal-fired fleet at the start of the year.

Crude Output

Even as emissions-free generation capacity is being built, lakes of petroleum are still being pumped out of the ground, refined and burned.

The EIA on Aug. 8 also released its August *Short-Term Energy Outlook*, which bumped the prediction for average daily crude oil production 200,000 barrels a day higher than the July outlook. That puts it in record territory for the U.S.

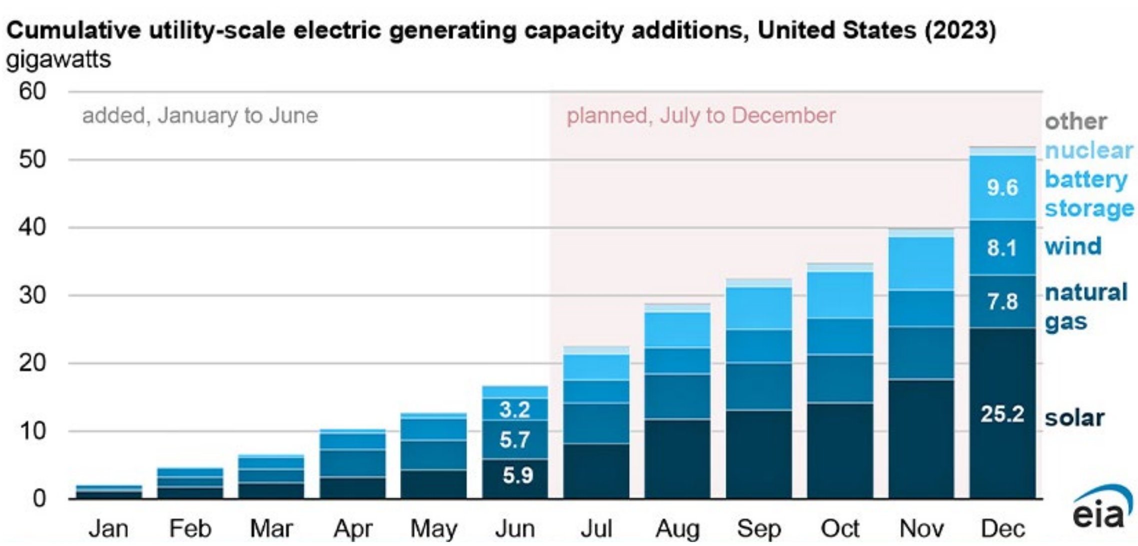
The "why" is simple: because there's money to be made on the global market, as demand persists amid Saudi Arabia's production cutbacks.

The global benchmark Brent Crude started July at $74.52/barrel and ended the month at $85.22, EIA reported. The agency expects it to reach $90 this year.

"We forecast continued growth in domestic oil production, which is bolstered by higher oil prices and higher well productivity in the near term," EIA Administrator Joseph DeCarolis said in a *news release* Aug. 8 announcing the outlook.

The U.S. likely approached a single-month record for electricity consumption in July, according to the report, as temperatures soared and air conditioners hummed. EIA estimated Americans used 388 billion kWh last month.

Coal use is expected to drop sharply from 513 million short tons in 2022 to 410 million this year, while natural gas is expected to generate 42% of the U.S.' electricity this year. Other large sources are projected to be nuclear (19%), coal (16%), wind (11%), hydro (6%) and solar (4%). ■



Utility-scale generation brought online in the first half of 2023 and projected to come online in the second half of 2023. | *EIA*

CAISO/West News

Calif. to Keep Old Gas Plants Operating for Reliability

Once-through Cooling Plants were Scheduled to Retire in 2020

By Hudson Sangree

The California Energy Commission agreed Wednesday to keep three old, environmentally damaging gas-fired plants operating along the Southern California coast for grid reliability, despite an outpouring of opposition from local residents and environmental groups.

It was the second three-year extension given to the once-through cooling plants, which had been scheduled to retire because of their harm to marine life and polluting of oceanside neighborhoods. But the state has deemed them necessary as it struggles to keep the lights on during heat waves while transitioning to 100% clean energy by 2045.

Energy Commission Chair David Hochschild called keeping the OTC plants operating a "collective failure," even as he and his fellow commissioners voted to approve capacity agreements between the state Department of Water Resources (DWR) and the plants in Long Beach, Oxnard and Huntington Beach, Calif.

"I look forward to the day not just when these three facilities are retired, but when all fossil fuel generation is retired," Hochschild said. "We have to build that future, and I believe we can. What's aggravating for me is that we're doing it, but we're late."

The vote followed more than two hours of impassioned testimony from those who live near the plants, saying they and their family members had been sickened by emissions and wanted the plants closed down, as planned, this year.

"What I hear here is this is a crisis of betrayal, a feeling of absolute trauma that communities feel over and over," CEC Vice Chair Siva Gunda said in response to the residents' pleas. Gunda said he found the decision difficult but was bound by the state's need to avoid blackouts.

An extreme heat wave led to rolling blackouts in California in August 2020, followed by energy emergencies caused by heat waves and wildfires in the next two summers.

The commission's decision approved DWR's *plan* to spend up to $1.2 billion to maintain selected units at the Alamitos Generating Station in Long Beach, the Huntington Beach Generating Station in Orange County and the Ormond Beach Generating Station in Oxnard for three more years, until Dec. 31, 2026.

The once-through cooling plants, which had originally been set to retire in 2020, had already gotten a reprieve until 2023 for the sake of reliability.

AES Corp., based in Arlington, Va., owns the Alamitos and Huntington Beach plants, while Houston-based GenOn owns the Ormond Beach facility. Collectively, the units to be kept online can generate nearly 2,900 MW of capacity.

DWR will issue the companies fixed monthly capacity payments of $8.82/kW-month to $10.95/kW-month, for a three-year total of as much as $1.19 billion. The department runs the state's Electricity Supply and Strategic Reliability Reserve Program, which acts as a backstop to provide incremental power during extreme events.

Legislation passed hastily in June 2022 assigned the role to DWR and approved Gov. Gavin Newsom's proposed $5.2 billion strategic reliability reserve consisting of "existing generation capacity that was scheduled to retire, new generation, new storage projects, clean backup generation projects, [and] diesel and natural gas backup generation projects."

(See *California to Pass Sweeping Energy Policy Changes*.)

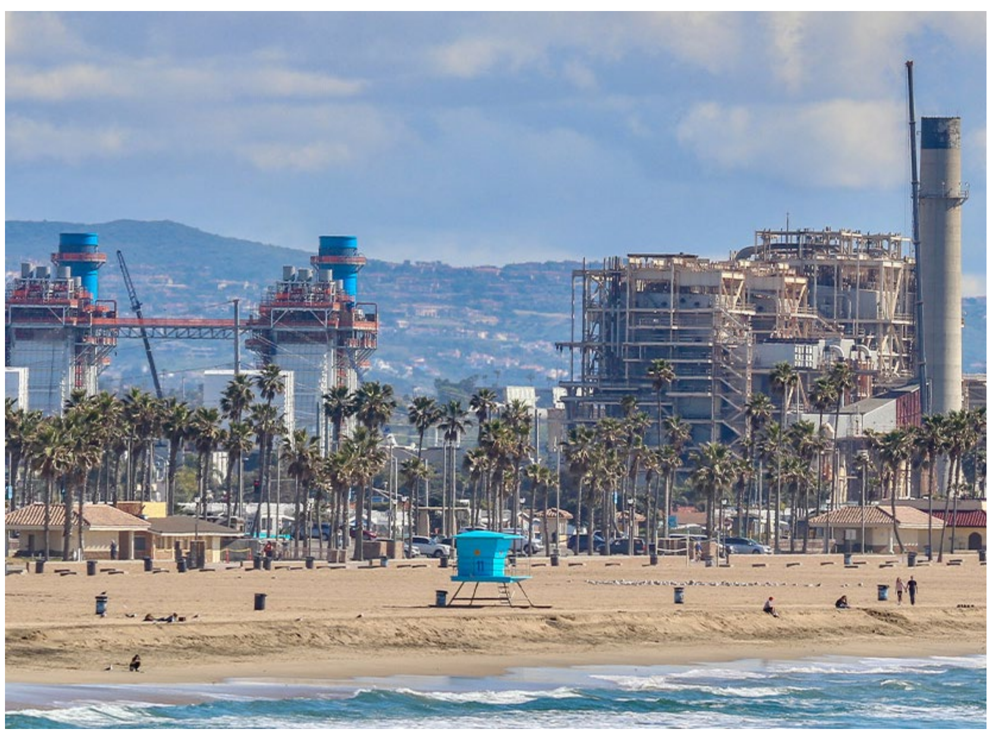
Critics lamented the bill in large part because the once-through cooling plants would likely be retained as part of the reliability reserve.

The plants, built in the 1950s and 1960s, use ocean water for cooling, killing billions of marine organisms. In 2010, the State Water Resources Control Board ordered the phase-out of 19 OTC plants along the coast.

Some plants retired, and others updated to air-cooling or alternative water-cooling technologies. The last three plants — Alamitos, Huntington Beach and Ormond Beach — still use their original cooling designs.

The hulking plants loom over densely populated coastal communities, wetlands and sandy beaches. Many residents and elected officials have wanted them closed for years because they are noisy, unsightly and polluting, but California's energy shortfalls have extended their lifespans.

The State Water Resources Control Board must still sign off on the DWR to keep the OTC plants online. It has scheduled a *hearing* for today to consider the extension, which it is expected to approve. ■



AES Huntington Beach| *Shutterstock*

CAISO/West News

NM Commission to Set Standards for RTO, Day-ahead Participation

Commission's Guidance Questions May Result in Series of Workshops

By Elaine Goodman

The New Mexico PRC's headquarters in Santa Fe | *New Mexico Public Regulation Commission*

New Mexico regulators have launched a process to develop "guiding principles" regarding participation in a regional day-ahead market or RTO.

The Public Regulation Commission on Thursday voted 3-0 to approve an *initial order* opening a docket on the matter and scheduling a workshop at 2:30 p.m. Sept. 21.

The docket will be used to investigate factors that two investor-owned utilities in the state, Public Service Company of New Mexico (PNM) and El Paso Electric (EPE), should consider when deciding whether to enter an RTO or day-ahead market. Both utilities currently participate in CAISO's Western Energy Imbalance Market.

Following one or more informal workshops, the PRC may opt to begin a formal rulemaking process.

Commissioner Patrick O'Connell called the order "a good step forward on a very important topic."

"This is not a trivial thing," O'Connell said. "I think there is a lot of potential value for our customers. Getting it right is where the work is."

The commission also gave a homework assignment to PNM and EPE in the form of questions to answer in writing on RTO and day-ahead market issues. The utilities will present their answers during the workshop.

The questions are organized under 14 topics. On the topic of reliability, the commission wants to know whether system reliability is improved by regional market participation and how a utility's responsibility for local reliability might change.

Two questions fall under the topic of transmission. The commission has asked if participation in a day-ahead market would improve the transmission system for New Mexicans and how that would compare to joining a full RTO. A second question asks whether the regional market should require participating transmission providers to make all their capacity available to the market and what exceptions should be made.

Under the topic of market transparency and performance, the utilities will discuss the types of data that would be provided to the commission and the public to assess market performance.

On another topic, the utilities were asked to describe the impact of joining either CAISO's Extended Day-Ahead Market or SPP's Markets+ on "seams."

Another question is how rural electric cooperatives can participate in the market.

With dozens of questions for the utilities to answer, the commission could decide that a series of workshops is needed, rather than a single session.

The PRC has also asked Southwestern Public Service (SPS), which is a member of SPP, to submit written comments about benefits or impacts to ratepayers resulting from RTO participation.

Other stakeholders are encouraged to participate in the process.

"Stakeholders' comments here about what they expect to get out of regional markets will be very valuable as we try to develop the guidance principles and expectations," Commissioner Gabriel Aguilera said.

New Mexico's effort comes just as competition is heating up between CAISO and SPP over their respective efforts to bring day-ahead markets to the West, which would likely be a precursor to a full RTO. (See *In Contest for the West, Markets+ Gathers Momentum — and Skeptics*.) ■

West news from our other channels

Wash. Auctions Reserve Carbon Allowances to Relieve Price Pressure

NetZero Insider

Newsom Orders up Hydrogen Strategy for California

NetZero Insider

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CAISO/West News

SoCalGas, CPUC Settle Aliso Canyon Case

Settlement Includes $71M Penalty and $485.5M in Unrecovered Costs

By Hudson Sangree

The California Public Utilities Commission issued a decision Thursday adopting a settlement over the massive natural gas leak at the Aliso Canyon Natural Gas Storage Facility in 2015 that includes a $71 million penalty against Southern California Gas, the facility's owner.

As part of the settlement, SoCalGas agreed it would not try to recover $485.5 million in costs related to the incident and it would refund more than $18 million to ratepayers. It also admitted to a violation of Public Utilities Code section 451, which requires public utilities to operate their facilities safely.

The CPUC's *decision* approved an agreement between SoCalGas and the CPUC's Safety and Enforcement Division and Public Advocates Office.

"The settlement agreement … is consistent with the record in that it includes an admission of a safety violation of section 451 for the totality of the Aliso Canyon incident, as well as a significant fine consistent with the magnitude and impacts of the violation," it says.

CPUC President Alice Reynolds and administrative law judges Jessica Hecht and Marcelo Poirier drafted the decision.

Ratepayer advocates opposed the settlement as premature and possibly inadequate.

The proceeding against SoCalGas was initially "phased," with "Phase 1 devoted to the number and nature of violations and Phase 2 covering costs, fines and penalties," The Utility Reform Network (TURN) and the Southern California Generation Coalition (SCGC) noted.

Phase 2 was never litigated, and the settlement bypasses it, TURN and SCGC said.

"Under the settlement, all of the Phase 1 and Phase 2 issues will be resolved, with SoCalGas bearing $610 million in purported monetary remedies in exchange for an admission of a single violation of [the] Public Utilities Code," they said.

"Despite the extensive litigation that has already occurred, the key discussion of costs assigned to Phase 2 has not yet occurred [and] the record is insufficient to determine that the monetary remedies identified are appropriate," they said.

The settlement overstates the dollar value of the settlement because "in order for the commission to assess whether the proposed monetary remedies are a sufficient penalty for the conduct at hand, the commission must first assess whether the included dollars would have been appropriate to collect from ratepayers under any circumstances," TURN and SCGC argued.

The CPUC decision agreed "that a disallowance of cost recovery cannot be considered equivalent to a penalty unless the foregone amount was likely to be recoverable from ratepayers" but said that "in this instance, the settlement agreement clearly protects ratepayers from the risk of litigating hundreds of millions of dollars of potential costs, some of which likely would have been found to be reimbursable by ratepayers.

"In principle, we agree with the opposing parties that the settlement motion may overstate the value of the settlement for ratepayers; nevertheless, we find that SoCalGas's agreement to forego cost recovery provides some (perhaps non-quantifiable but still real) ratepayer value," the decision says.

The decision adopting the settlement, known as a presiding officer's decision, takes effect after 30 days unless a party appeals it or a commissioner requests a public review.

"In case of an appeal or request for review, administrative law judges will assess and potentially modify the decision before presenting it to the commissioners for voting during a public session," the CPUC said. "Commissioners may also offer an alternate decision for consideration."

The SS-25 well at Aliso Canyon spewed 107,000 tons of natural gas over four months. | *Blade Energy Partners/ CPUC*

Proposal to Replace

In a separate proceeding, the CPUC has proposed replacing Aliso Canyon, the state's largest natural gas storage facility, with a combination of non-gas-fired generation, building electrification, energy efficiency and storage. (See *California PUC Proposes Aliso Canyon Endgame*.)

The facility's fate has been controversial since a ruptured pipe at the SS-25 well poured more than 100,000 tons of natural gas into the air, leading to a blowout and sickening nearby residents. The leak was contained after four months in February 2016.

After the gas leak, the facility reopened at reduced capacity in July 2017, but in November 2021, the CPUC increased its storage limits by 7 billion cubic feet (Bcf) to just over 41 billion Bcf amid concerns about winter gas supply. At the time, it rejected a plan to increase the allowable storage to 69 Bcf. (See *CPUC Approves More Gas at Aliso Canyon*.)

On July 28, the CPUC issued a proposed decision that would increase the maximum storage level allowed at Aliso Canyon from 41 billion cubic feet to 69 Bcf "on an interim basis to help secure energy reliability and protect against high natural gas and electric prices."

The *proposal* is scheduled to be taken up at the CPUC's Aug. 31 voting meeting. ■

ERCOT News

Vistra Generation Helping ERCOT Meet Record Demand

Texas Grid Operator Breaks 85 GW with Latest Summer Peak

By Tom Kleckner

Vistra CEO Jim Burke said Wednesday that Luminant's generating fleet has performed well amid Texas' ongoing heat wave, which has led to multiple demand records this summer.

"The units are running hard. There's no end in sight for this heat that we're in," Burke told analysts during the company's quarterly conference call. "The team is doing a terrific job keeping these units online, and I would say overall, the ERCOT grid and the operators have done a nice job keeping the grid supplied. It's a daily focus for us."

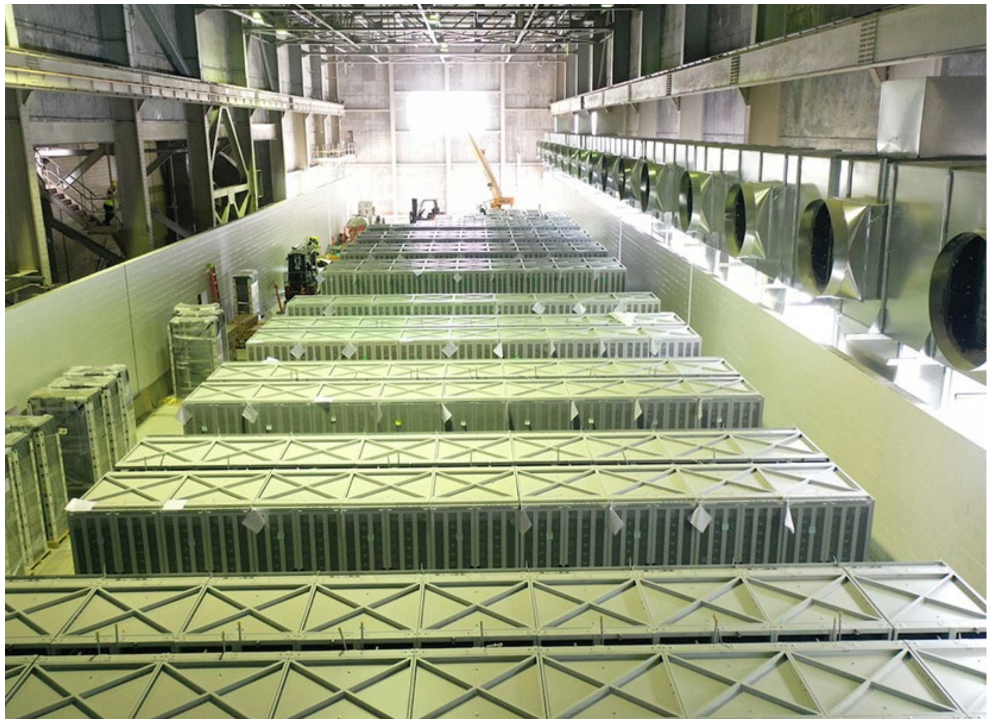
The Texas grid operator set three new highs for average hourly demand last week, breaking 84 GW and 85 GW for the first time Thursday. ERCOT's new mark of 85.44 GW broke previous records set Aug. 7 and Wednesday at 83.85 GW and 83.96 GW, respectively. The new demand peak is unofficial until settlements are made.

ERCOT staff projected demand to peak at 82.74 GW in its final summer resource adequacy assessment. Demand has met or exceeded that projection 46 times this summer, 14 times since Thursday. The ISO still is operating under a weather watch, its fourth of the year, that has twice been extended through this Friday because of the higher temperatures and demand and a potential for lower reserves. Grid conditions are expected to be normal and ERCOT is not calling for conservation.

Burke said that while the Texas grid's newest ancillary service, ERCOT contingency reserve service, has helped maintain a plump cushion of reserves and avoided emergency conditions, "it does not solve the broader problem that we entered the [2023 legislative] session trying to solve."

He said although lawmakers' objective was to retain and incent new thermal generation, "we ended up with a menu of things."

"Frankly, it's a ton of work for the Public Utility Commission and ERCOT to work through this. They're going to have their plate more than full," Burke said. "There's a lot still to figure out, and we'll obviously be active and work with stakeholders involved to try to bring clarity to it."



Moss Landing's turbine hall | *LG Energy Solution*

The Irving, Texas-based company completed a 350-MW expansion of its Moss Landing energy storage facility in California during the quarter, increasing its capacity to 750 MW and, according to Vistra, making it the largest battery storage resource in the world. It also said it's making progress on its announced acquisition of Energy Harbor.

Vistra reported $1.01 billion in ongoing operations adjusted earnings before interest, taxes, depreciation and amortization (EBITDA), an improvement over the $756 million realized during the same period a year ago. It said the increase was driven primarily by higher energy margins through its hedging strategy, backing down generation when prices were below unit costs, and strong performance in its retail segment, partly offset by less favorable weather.

The company uses adjusted EBITDA as a performance measure because, it says, outside analysis of its business is improved by visibility into both net income prepared in accordance with GAAP and adjusted EBITDA.

Vistra's share price closed at $30.69 Thursday, up $1.87 from Aug. 8's close.

OGE Energy Retiring, Replacing 2 Gas Units

OGE Energy also released its quarterly financial results Wednesday. Oklahoma Gas & Electric's parent company reporting earnings of $88 million ($0.44/diluted share), up from last year's same period of $73 million ($0.36/diluted share).

The company said it has requested approval from Oklahoma and Arkansas regulators to retire and replace two aging gas-fired steam turbines at its Horseshoe Lake power plant in eastern Oklahoma with two newer gas combustion units. The proposed $331 million project would replace the two units that also can burn fuel oil with 450 MW of more efficient generation.

The two retiring units have a combined capacity of 383 MW. They have been in service since 1958 and 1963.

"These units are a great first step in meeting the future generation capacity needs of our company," CEO Sean Trauschke told financial analysts.

OGE said it has submitted four funding applications to the Department of Energy under the Infrastructure Investment and Jobs Act to help pay for the project.

OGE's share price closed at $34.46 Thursday, up 18 cents from its close Aug 8. ■

ISO-NE News

ISO-NE Proposes 21.5% Budget Increase for 2024

Officer Pay Increasing 6%; Lobbying to Total $400,000

By Jon Lamson

ISO-NE *proposed* a 21.5% increase in its revenue requirement for 2024 last week, citing the need to retain and expand its workforce to enable the clean energy transition. The RTO presented the $244.5 million operating budget and $35 million capital spending plan to the NEPOOL Budget and Finance Subcommittee on Friday.

In response to the proposed increase, some public advocacy groups have criticized the RTO for a lack of transparency and engagement with the public on its budget process, arguing that these issues indicate a lack of accountability to ratepayers.

"I don't see it as reasonable that New England ratepayers are minting new millionaires every year at ISO-NE, and we don't even have the ability to question those financial packages," said Tyson Slocum, director of Public Citizen's Energy Program. "Thousands of New Englanders who are really struggling to make ends meet with continued rate hikes across the region are shut out of the process. They can't go and share their grievances; they're literally locked out of the room."

ISO-NE first proposed a preliminary version of the budget to the Participants Committee (PC) in June. (See *ISO-NE Considers Major Capacity Market Changes*.) The RTO said it needs $27 million for "catch-up" adjustments to current employee salaries and investments in information technology, cybersecurity and the transition to cloud-based infrastructure; $11.5 million for the revenue requirement true-up; and almost $10 million for 35 new employees to respond to the clean energy transition.

"Our executive compensation structure is designed to attract and retain top-tier talent essential to overseeing the complex energy landscape and ensuring the reliability of the regional power grid," an ISO-NE spokesperson told *RTO Insider*. "We regularly review and benchmark our executive compensation against industry standards to ensure it remains competitive, fair and aligned with our performance goals."

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

The draft budget also includes a placeholder headcount for a position focused on environmental policy and community engagement, following the request by five of the six New England states (all but New Hampshire) for an executive-level environmental justice position at the organization. (See *States Call for an Executive-level EJ Position at ISO-NE*).

Mireille Bejjani of environmental justice organization Slingshot applauded the inclusion of this position and the addition of staff and resources dedicated to the clean energy transition.

"I think the key distinction is, are we paying existing leadership — who are already making a lot of money — even more money, or are we paying for more staff to be able to accelerate the clean energy transition?" Bejjani asked.

According to ISO-NE's 2021 IRS Form 990, ISO-NE CEO Gordon van Welie made about $2.4 million in 2021, while COO Vamsi Chadalavada made nearly $2 million. Meanwhile, salaries for members of the Board of Directors working about 10 hours per week ranged from $113,000 to $173,000.

The 2024 draft budget includes $5 million for the base salaries of the 11 officers, a roughly 6% increase over the $4.7 million *requested* in 2022. ISO-NE executives also make a significant portion of their total income outside of their base salary; van Welie and Chadalavada both made more in bonus and incentive compensation than in their base salaries in 2021.

"Especially this past winter, lower-income communities were hit really hard with rate increases and having to potentially choose between paying their electric bills and putting food on the table," Bejjani said. "If those bills go up even a small percentage per month, that can make a huge impact on lower income communities, just to pad the pockets of people who are already making well over six figures a year for not very much work, in the case of the Board members, and for [van Welie] and the other top leadership, upwards of a million dollars."

ISO-NE estimated that the budget increase would cost the average ratepayer 28 cents per month, bringing ISO-NE's total charges to around $1.46 per consumer per month, or about $18 each year, assuming an average monthly electricity consumption of 750 kWh. The presentation said ISO-NE's total operating expenses were on the lower end compared to NYISO, CAISO, IESO, PJM, MISO, SPP and ERCOT.

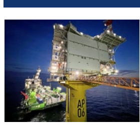
Slocum said since ratepayers pay ISO-NE's cost regardless of performance, they must be given access to the RTO's budgetary proceedings. He also argued that bonus compensation should be more transparently tied to performance.

"It doesn't seem just and reasonable to pay such extravagant salaries and bonuses with no corresponding accountability," Slocum said.

Beyond executive compensation, the proposed budget includes about $300,000 for state-level lobbying and $100,000 for federal lobbying, paid to external consultants. Over the first half of this year, ISO-NE spent $60,000 on federal lobbying, *employing* former Bush administration official Adam Ingols. ISO-NE also spent $45,000 on its Massachusetts lobbying operation.

ISO-NE plans on reviewing the proposed budget at the September PC meeting, followed by a PC vote in October. ■

Northeast news from our other channels



Ørsted Addresses Challenges of US OSW Market

NetZero Insider

RTO Insider subscribers have access to two stories each monthly from *NetZero* and *ERO Insider*.

ISO-NE News

Green Mountain Power to Expand Mobile Battery Fleet

Locally Built System Aids Load Management, Emergency Response

By John Cropley

Vermont's largest electrical provider and a home-grown battery system manufacturer are expanding their fleet of portable utility-scale energy storage in the state.

Green Mountain Power and NOMAD Transportable Power Systems have been designated for a $9.5 million U.S. Department of Energy grant to create new resiliency zones in five Vermont communities with a history of power outages during extreme events.

GMP bought one of NOMAD's 2-MWh trailer-mounted systems last year and the DOE grant will help pay for five more.

That first unit has been used for grid resilience since it arrived. It got its first field test last month during a planned outage near a manufacturer with round-the-clock operations.

"This was the first time we deployed it to benefit a customer," GMP spokesperson Kristin Carlson told *RTO Insider*. "We had already been using it for load management. The NOMAD units are really a game-changer because they're mobile."

The utility already had trucks large enough to haul the NOMAD. So when it was time to upgrade the power lines near Twincraft Skincare in Colchester, GMP calculated Twincraft's electrical load, moved the battery to the site and back-fed a transformer.

GMP then re-energized just enough of the area to power the manufacturing operations while the utility crew worked safely for six hours on the de-energized lines.

Images of Vermont were in the national eye just a few days later, as a slow-moving rainstorm inflicted epic flooding on many small towns.

But while such emergencies are one of the crises the NOMAD system is designed to meet, it was not needed this time.

"We were actually able to get people back online pretty quickly," Carlson said.

That has not always been the case.

Vermont is the 43rd-smallest and 49th-most-populous state, and the residents are widely dispersed. Its hills and mountains can make for slow travel in severe weather.

Also, its grid is chopped into a patchwork of service areas. GMP, the state's only investor-owned electric utility, serves more than 270,000 customers; two cooperatives and 14 municipal utilities power everyone else.

The federal grant is designed to demonstrate long-duration energy storage in military housing and in remote communities such as those in rural corners of Vermont.

Carlson said the NOMAD will be an important tool in building resilience in the face of climate change, but it's just one of the tools GMP is using.

The utility is continually expanding its virtual power plant and energy storage network. It now stands at about 50 MW of utility-scale batteries, controllable EV chargers and 4,500 residential battery systems.

Green Mountain Power's mobile 2-MWh battery system | *Green Mountain Power*

GMP has carried out pilot projects with vehicle-to-grid charging but is waiting for technology to evolve before integrating it on a wider scale.

NOMAD Transportable Power Systems is going to market with three models that it will fabricate in Waterbury, Vt. — the 1-MW/2-MWh Traveler that GMP has been using and two smaller models.

It recently sold its second unit, a spokesperson told *RTO Insider*, and is getting attention both for its adaptability and as an alternative to emergency diesel generators.

In carrying out the DOE grant, GMP and NOMAD will be joined by KORE Power, the lithium-ion battery cell and module manufacturer that launched NOMAD in 2020.

Electric reliability research organization EPRI will study the cost and reliability benefits of the project.

And in the process, GMP will create more of its Resiliency Zones, in which it combines backup batteries and local renewable power generation to limit outages in communities. ■

ISO-NE News

NEPOOL Markets Committee Briefs

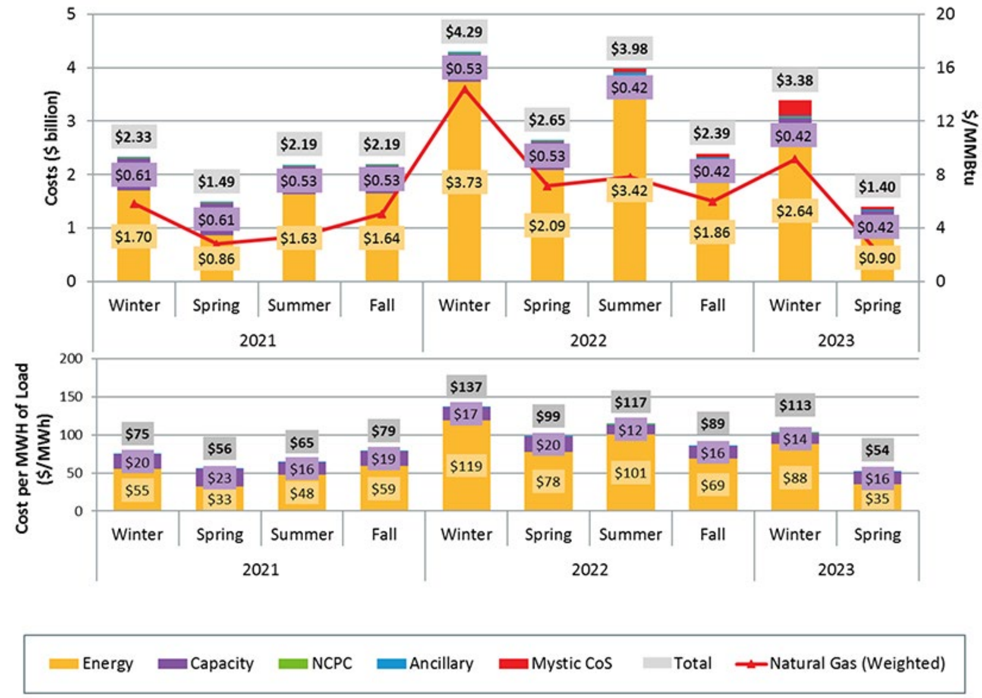
By Jon Lamson

New England wholesale market costs were significantly lower in the spring of 2023 compared to spring 2022 and 2021, the ISO-NE Internal Market Monitor (IMM) *told* the Markets Committee on Wednesday.

The IMM noted that wholesale costs declined by 47%, or $1.25 billion, compared to spring of 2022, attributing the decrease to lower natural gas prices, which were down 69%. The IMM also said load was lower this spring because of a relatively cold May.

The monitor added that capacity market costs were down 21%, reflecting lower clearing prices from the Forward Capacity Auction (FCA) 13 relative to FCA 12.

Looking at the resource mix, oil generation declined from 13% to 11% of the average output, while gas generation increased from 43% to 47%. Nuclear generation decreased by 354 MW compared to last spring, from 21% to 19% of average output, "due to refueling outages and unplanned outage continuation," the IMM reported.



Wholesale electricity costs by season from 2021-2023 | *ISO-NE*

Barriers to Entry for Retired Resources

Also at the Markets Committee summer meeting, ISO-NE *proposed* removing the cost requirements for retired resources looking to re-enter the Forward Capacity Market (FCM). The most recent rules for resources looking to re-enter the FCM include an investment requirement of $417 per kW.

"These requirements apply to any re-entering resource after it has retired, regardless of its retirement elections and/or a reliability retention agreement," said Ryan McCarthy of ISO-NE.

McCarthy said the requirement is intended to discourage generators from retiring and re-entering just to access unique pricing rules for new resources. Because these unique pricing rules have been removed, the investment requirement no longer is needed, McCarthy told the committee.

"As things stand currently, the investment requirement could create a barrier to cost-effective and timely re-entry of resources," McCarthy said. "The ISO proposal removes the investment requirement for fully retired or permanently delisted resources seeking to requalify for the FCM."

ISO-NE has proposed an October vote on removing the requirement, with an effective date of quarter four of 2024.

FCA 19 Uncertainty

The main focus of the Markets Committee summer meeting was discussing options for the format and timing of FCA 19. (For a more detailed breakdown of last week's discussion, see *NEPOOL Debates Options for FCA 19*.) Many NEPOOL members have supported delaying the auction a year to implement resource capacity accreditation (RCA) changes, and to consider moving to a prompt and seasonal capacity market.

"Getting the capacity market right is incredibly important," Ben Griffiths of LS Power told *RTO Insider*. "We support a one-year delay in FCA 19 to give the ISO and stakeholders time to fully vet RCA and other possible changes in market design that will be in place for years to come."

However, some clean energy companies have expressed worries about how a delay would impact new resources which did not receive commitments in FCA 18.

"In ISO-NE, the process for generators to have their capacity deliverability studied and secured currently resides within the FCA qualification process and not in the interconnection process as in some other regions," said Alex Chaplin of New Leaf Energy. "Postponing FCA 19 would suspend this pathway to secure capacity deliverability, making new resource development in the region substantially riskier."

Chaplin said this added uncertainty likely would increase the cost of capital for new resources in FCA 19, putting some projects in jeopardy.

"This would slow the pace of the clean energy transition and may introduce reliability concerns in light of ISO-NE's rising forecast peak loads," Chaplin said.

Cost of New Entry Changes

ISO-NE also detailed potential changes to its process of calculating Cost of New Entry (CONE) and Net CONE for FCA 19 and 20.

Using FCA 18 as a baseline, ISO-NE found that the updated formula would have increased CONE by 4.2% and Net CONE by 6.5%.

The RTO plans to vote on the proposal at the Markets Committee in September, with an effective date of March 2024. ■

ISO-NE News

NEPOOL Debates Options for FCA 19

By Jon Lamson

STOWE, Vt. — ISO-NE last week solicited feedback from the NEPOOL Markets Committee on several options for the timing and overall design of Forward Capacity Auction 19.

FCA 19 will procure capacity for the 2028/29 capacity commitment period. While the RTO had hoped to implement resource capacity accreditation (RCA) changes in FCA 19 aimed at improving estimations of gas generator winter reliability limitations, a software error related to LNG availability has delayed the process. (See *ISO-NE Outlines More of Plans for Capacity Accreditation, DA Ancillary Services*.)

NEPOOL is also considering a move to a prompt seasonal capacity market and whether this move should be initiated for FCA 19, at a later date or not at all. (See *Discussion Continues on ISO-NE Capacity Market Changes*.)

ISO-NE has *laid out* a series of options for stakeholders to consider for FCA 19, asking for input on preferred routes:

1. conduct FCA 19 using the current market rules without implementing RCA.
2. push the auction date back a year, from 2025 to 2026, and include RCA changes.

2a. plan to implement RCA in FCA 19 with the auction held in 2026, but decide by Q3 2024 whether to instead move to a prompt and seasonal auction held in 2028.

3. transition to a prompt and seasonal auction for FCA 19, with the auction held in early 2028, providing time to implement RCA.

"In each of the options, the start of CCP 19 remains the same. The timing of the pre-auction processes and auction varies," Tongxin Zheng of ISO-NE told the committee.

ISO-NE has not endorsed any of the options and has said that all of them remain on the table.

Several committee members expressed support for delaying the auction a year to help consider and potentially implement significant changes.

Massachusetts Assistant Attorney General Ashley Gagnon wrote in a *memo* prior to the meeting that a one-year delay of FCA 19 "to determine the appropriate path forward for FCA 19/CCP 19 is worth serious ISO and stakeholder consideration and discussion given the importance of the decision and the current lack of information essential to making an informed decision."

Gagnon said that delaying the auction would allow ISO-NE to finish the RCA design process and more thoroughly contemplate the possibility of moving to a prompt and/or seasonal market. Gagnon also stressed the importance of keeping ratepayers in mind while contemplating the options.

"The AGO [Attorney General's Office] recommends that potential costs to consumers be an explicit consideration and evaluation metric in deciding the optimal path forward for CCP 19 and beyond. While the AGO recognizes that potential costs to consumers may be difficult to analyze at this stage, consumer impacts are critical and should inform the decision-making process," Gagnon said.

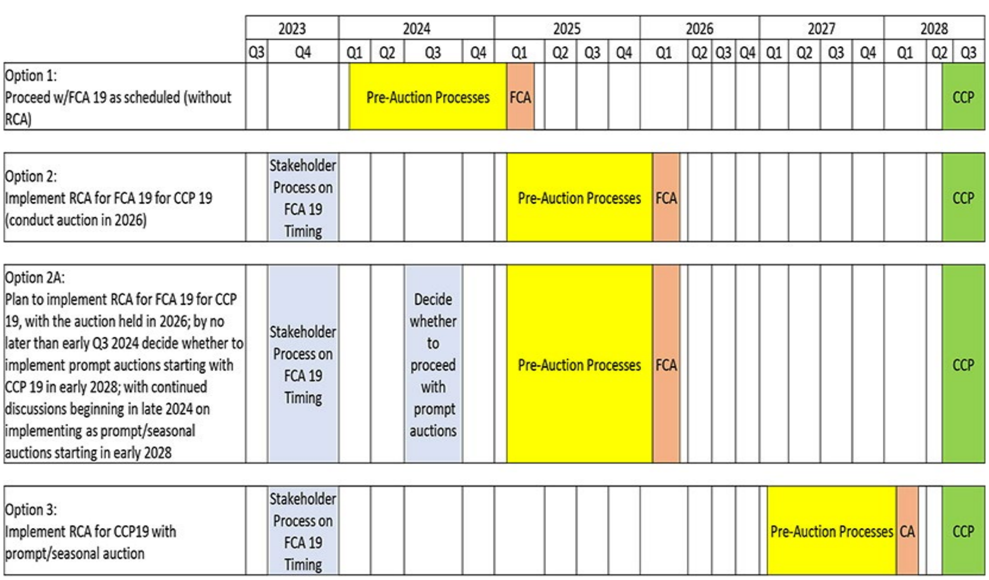
Brett Kruse of Calpine also expressed his support of option 2a, noting that the company has been advocating for a move to a prompt capacity market for several years.

"We're fine with a one-year delay for FCA 19 in order to allow ISO-NE to implement RCA (option 2) but marginally prefer 2a because of the addition of the prompt procurement aspect," Kruse told *RTO Insider*. "We're interested in option 3 that would also add a seasonal market design, but need to be comfortable with some details about the design, which is fairly conceptual at this point."

Eric Wilkinson of Ørsted said that the capacity market changes must properly account for the reliability attributes of renewables.

"Ørsted supports ISO-NE's efforts to revise their capacity market rules," Wilkinson said. "As the fuel mix for electric generation continues to evolve, it is important that the capacity market appropriately values the contributions to system reliability that renewable resources, including offshore wind, provide."

ISO-NE plans on choosing an option by late September and bringing forward a proposal in October.



Timelines for CCP 19 options | *ISO-NE*

Seasonal Auction Timing

ISO-NE also presented some pros and cons of holding seasonal auctions within a given CCP simultaneously or serially.

"Either approach could be used with a forward or prompt procurement of capacity," said Chris Geissler of ISO-NE. "However, pros/cons associated with each depend on whether procurement is forward or prompt."

Geissler said that the benefits of serial seasonal auctions could be more pronounced under a prompt construct, which would allow the auction to reflect the most up-to-date information.

Meanwhile, Geissler noted that holding the auction simultaneously would enable capacity sellers to specify different offer prices for each season and the entire CCP, as well as helping to ensure revenue sufficiency for sellers. ■

MISO News

MARC 2023 Touches on Order 2023, Interconnection Troubles

Stakeholders Discuss Pain Points with New Capacity

By Amanda Durish Cook

GRAND RAPIDS, Mich. — This year's Mid-America Regulatory Conference took notice of FERC's recent set of interconnection rule changes.

Experts on an interconnection panel Aug. 7 were hopeful that the commission's Order 2023 — meant to alleviate queue backlogs, give developers certainty and prevent discrimination against new technologies — will fix some of the problems plaguing queues (*RM22-14*). (See *FERC Updates Interconnection Queue Process with Order 2023*.)

"We know the symptom of the interconnection problem, but what's the cure?" Iowa Utilities Board Commissioner and panel moderator Joshua Byrnes asked panelists in a room packed with attendees.

AEP Vice President of Transmission Planning Kamran Ali said he thought Order 2023 will result in "cleaner" interconnection queues, though the jury is still out on whether it will encourage more capacity to connect.

"We're capacity-short in a lot of areas because load is pushing resource requirements up," Ali said.

Clean Grid Alliance Executive Director Beth Soholt said FERC's order is helpful to spur transmission providers to bring new generating capacity online and not simply be motivated to preserve the existing resources on the system.

"We're talking about a lot of turnover. We have a lot of retirements; we must get a lot of megawatts through in a short amount of time. We have to look at both sides of the ledger. What can interconnection customers do, but what can MISO and transmission owners do? It's not working well today," Soholt said.

Enel North America's Gina Mace said she was glad to see FERC placed emphasis on the commercial readiness of generation projects in Order 2023.

Mace also said queues "could see a lot of progress" if long-term transmission planning is co-optimized with interconnection planning. She said today's transmission system is ill-suited to how scattered generation is becoming.

Soholt said in a perfect world, there would be that same comprehensive planning in MISO, in addition to many more engineers to study two cycles of entrants per year.

CGA's Beth Soholt (left) and Enel North America's Gina Mace | © *RTO Insider LLC*

Soholt said transmission owners should communicate with interconnection customers earlier to signal whether proposed points of interconnection are feasible. She also said MISO is on the wrong track to propose to cap the number of megawatts annually that it will study. MISO has proposed to restrict queue submissions to a 60%-of-peak-annual-load (about 73 GW) annually, triple its entry fees and establish more rigorous land obligations and escalating penalty charges. (See *MISO Aims for Manageable Interconnection Queue*.)

"If you cap the megawatts, you're going to have people lining up five years ahead just to enter the queue," Soholt said, asking if that scenario is conducive to the rapid plans for a clean energy transition.

"The demand is there. We've got to get them through the process," Soholt said.

Mace said MISO needs more realistic study assumptions, a clearer notifications process if withdrawing projects stand to affect other projects and a plan to somehow reduce the interdependency among projects in its studies.

Ali said interconnection customers want some certainty before they commit to securing land. However, he said the quicksilver nature of earlier queued projects and the potential for re-studies mean interconnection queues probably will continue to be synonymous with uncertainty.

MISO has *said* the majority of the requirements "appear to generally align" with existing MISO process. It said it likely must tweak timelines, requirements and nomenclature in its interconnection process to match FERC's vision. ■

MISO News

Overheard at MARC 2023: Equity and the Energy Transition

By Amanda Durish Cook

MARC 2023 underway at the JW Marriott Grand Rapids | *© RTO Insider LLC*

GRAND RAPIDS, Mich. — The annual Mid-America Regulatory Conference (MARC) Aug. 6-9 again centered on the clean energy conversion and transmission expansion, this time with an undercurrent of equity.

MARC's 2023 conference, "Grand Vision: Past, Present, Future" originally was planned for late spring 2020 but was derailed by the pandemic until Aug. 6-9.

"It's a conference more than four years in the making," Michigan Public Service Commission Chair Dan Scripps said, welcoming regulators, utility representatives and "Barbies, Kens and even Allans" to the conference.

Equity Takes Center Stage

Multiple Indiana and Michigan-based grassroots equity and climate activist groups attended MARC this year, pressing regulators and utility representatives to decarbonize faster while addressing longstanding disparities in the grid's design.

Wisconsin PSC Chair Rebecca Cameron Valcq said the energy transition affords the industry "a once-in-a-generation opportunity and responsibility" to include vulnerable communities in environmental justice. She said those communities have good reason to distrust the systems in place and have been neglected "for hundreds of years."

Regulatory initiatives often are "dense and obtuse," Cameron Valcq said, making an informed and participating public an uphill battle. She said "there's more work to be done" in ensuring the public know where and when to comment.

Becca Jones-Albertus, director of the Solar Energy Technologies Office at the U.S. Department of Energy, said an "unevenly distributed" transition is underway, where some parts of the country already have rapidly transformed while other parts have little idea of what's in store for them.

Jones-Albertus said over the next few years, she expects 5-10% of power consumed to originate on the distribution system.

"We're at a fork in the road," said Jeffrey Schlegelmilch, director of the National Center for Disaster Preparedness at Columbia Law School. He said the industry can either view the transition through the "lens of equity" and extend the benefits of innovation to all, or it can exclusively lavish investments on wealthier areas, forcing poorer Americans to pay more for power, be neglected from environmental redress and continue bearing the brunt of reliability breaches and dangerous weather.

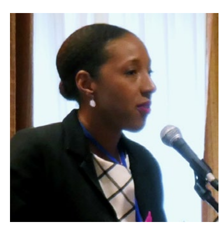
Schlegelmilch said societal and economic costs will be much lower if the industry brings everyone along on the clean energy overhaul. He said he's performed analyses where the medical costs of exacerbated health conditions and the "cascading impacts" of those costs alone make replacing a fossil fuel generator with a battery storage facility cost-effective in communities. But he also said that raises the question of who ultimately pays for action versus inaction.

Midwest Building Decarbonization Coalition's Marnese Jackson said historic racism, capitalism and a single-minded drive for corporate profit is making a truly equitable decarbonization increasingly unattainable. She called for an emphasis on shifting away from "dirty" natural gas as soon as possible.

Consumers Energy CEO Garrick Rochow said equity and environmental justice can be baked into the energy transformation. He said he believes carbon capture will factor heavily into the clean conversion, and natural gas generation will "fill in the gaps" and then "diminish." Rochow said once the grid is sufficiently greened, green hydrogen can enter the conversation.

Rochow also said Consumers has conducted unconscious bias analyses in its outage restorations and grid investments practices, something it "should have done 20 years ago."

"What we've found is we're investing more in our most vulnerable customers because the grid is in worse shape in those areas," he said.



Hilary Scott-Ogunrinde, Illinois | *© RTO Insider LLC*

In a session on planning a just transition for power plant communities, Hilary Scott-Ogunrinde, deputy director of energy and utility at the Illinois Department of Commerce and Economic Activity, said the state is trying to "rectify the wrongs of the past" through the Climate and Equitable Jobs Act (CEJA).

She asked the audience to guess how many coal plants have closed in Illinois in the past decade. After speculations ranging from five to 20, she said the number is 11.

Scott-Ogunrinde said after the rash of closures, Illinois passed CEJA, which contains

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grants for coal-to-solar facility changeovers, both for underprivileged individuals seeking to invest in renewable development and for communities transitioning from coal, nuclear, natural gas or mining operations.

Larry Steckelberg, an administrator of community services at the Michigan Department of Treasury, said Windsor, Ontario's twinkling lights across the Detroit River are in stark contrast to Detroit's lack of recreational waterfront, brownfield sites, abandoned factories and shuttered coal plants. He said River Rouge, Mich., the former site of heavy industry and DTE Energy's River Rouge coal plant, which closed in 2021, is one of the most polluted sites in Michigan and will take several years of remediation until people are enticed to move there.

Steckelberg said revitalizing a former coal plant city is a long-term project, often taking 15-20 years, with cities "swept up in global events" out of their control. He said he personally couldn't predict how fast coal would fall out of fashion globally.

Steckelberg said the town of Covert, Mich., was unprepared for the closure of the Palisades nuclear plant, even though indications were clear. He urged communities to diversify energy sources and not "just become a site" for solar panels because it's the trendy resource now. But he acknowledged that the list of federal resources and the requirements can be "bewildering" for some communities.

"Putting in layers of bureaucracy does not get the help that people need," Scott-Ogunrinde agreed. "…If we're going to have the money available, then have the money available. Because the people filling out the forms, they need it. Even if they don't have 20 pages of documentation."

EPA Senior Adviser Jon Grosshans said historically the U.S. has supported communities suffering manufacturing losses, but it hasn't provided backing for communities that transition from coal plants.

Grosshans said the federal government is seeking to create a "front door" for financial resources for transitioning communities.

"Sitting around in 2019, it was pretty obvious to us that this was going to be a decade of closing more coal and bringing on more renewables," said Emily Fisher, Edison Electric Institute executive vice president of clean energy.

Fisher said EEI quickly realized that net-zero plans would need to incorporate dispatchable technologies with the assistance of carbon capture, green hydrogen and long-duration storage.

A breakout panel during MARC 2023 | © *RTO Insider LLC*

EEI's Emily Fisher (left) and DTE Energy CEO Jerry Norcia | © *RTO Insider LLC*

"No company has released a plan that hasn't carefully thought this through," she said.

But Fisher said it became apparent over the past few years that "maybe this decade isn't going to be as easy as we thought it was going to be," referring to how difficult it remains for new generation to clear interconnection queues and receive grid treatment.

Fisher also said post-pandemic, utilities have become more acutely aware of affordability. She said when utilities raise concerns about customer affordability, it's often perceived as utilities trying to stall the clean energy transition. But she said utilities are justified in their concern whether costs can be recovered from ratepayers.

DTE Energy CEO Jerry Norcia said DTE's latest integrated resource means his utility is mounting an "aggressive" net-zero plan. (See *DTE, Activists Announce Agreement to Exit Coal by 2032*.)

"Solar seemed unreachable from an economics standpoint about 10 years ago. What seemed impossible a decade ago has become very, very possible," Norcia said.

Norcia also said he's optimistic about green hydrogen and predicted the technology will improve, and costs will plummet so that what seemed insurmountable will become achievable.

Norcia also said DTE's service territory has begun to see "violent storms… and weather patterns that were reserved for states south of us," upping the pressure to make infrastructure investments for the sake of reliability. He said the climate crisis and growing demand for electrification means utilities need to "build the grid out slightly ahead of time." He also said worsening weather means utilities need to seriously consider "how to get stuff underground," indicating burying lines.

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"That's something we're going to start experimenting with and seeing how we can get the costs down," he said.

Google Global Head of Energy Caroline Golin said Google is conscious it demands a lot of electricity and wants to accelerate the switch to carbon-free sources. She said Google is focused on how to partner with suppliers on pilot projects for green hydrogen, long-duration storage and carbon capture.

"I can tell you this [carbon-free] growth is coming, it's coming now, it's coming fast. We wanted it yesterday. …We will not grow somewhere where we don't see a goal," she said of renewable energy targets.

Golin also said Google doesn't want to wait on a "six-year interconnection queue" before planned generation can link up to the grid. Google aims to achieve net-zero emissions across all operations by 2030.

"We make two-year, three-year business commitments," she said.

Towering Transmission Investments

"What we do know is that the future is going to [be] significantly more complex than anything we've ever planned for before," SPP Vice President of Engineering David Kelley said, noting that the U.S. has sustained about 360 weather and climate disasters since 1980 where overall damages and costs have reached at least $1 billion. "Planning for a loss of load event every 10 years is no longer going to cut it," he said.

Advanced Power Alliance's Steve Gaw said transmission system expansion is necessary to unlock clean, low-cost energy and shrink congestion.

Gaw said if grid operators aren't proactively planning, "you're risking being 10 years behind."

"In the words of Dwight Eisenhower, I'd say plans are nothing — and basically worthless — but planning is everything," he said.

Gaw also said transmission projects — even ones built to further a lone public policy goal — rarely fulfill a single purpose. He said transmission often offers a myriad of economic, reliability and decarbonization benefits. He said it's nearly impossible to build transmission for a single goal.

"You've got to think about the consequences if you don't make that investment," ITC's Charles Marshall said of transmission planning, pointing out that his friend's electric bill will contain an up to $10 surcharge every bill for decades

From left: ITC's Charles Marshall, Advanced Power Alliance's Steve Gaw and FERC Commissioner Mark Christie | *© RTO Insider LLC*

to fund the recovery efforts after Winter Storm Uri because the system wasn't built to weather the storm.

FERC Commissioner Mark Christie said contrary to the perception of a crumbling and decrepit transmission system, there's a surge in new transmission projects.

"We've heard a lot about how the grid is old, it's creaky, it's built for a World War II era," he said.

But Christie said the national transmission rate base has tripled in the past decade and is set to double over the next eight years. He said grid planners need to be sensitive to regional costs. "You ain't seen nothing yet" in terms of how high transmission price tags will ascend in the coming years, Christie warned.

Siting infrastructure isn't going to get any easier, multiple panelists said.

"There's so much development that communities are reacting. They're being asked to solve global energy infrastructure problems, and they're thinking 'that's not my problem,'" University of Michigan Director Sarah Mills said.

Mills said developers should sell their projects as solutions to lift farmers' incomes and increase local tax bases.

Mills also said regulators should be upfront about collecting comments and if the contents stand to change the outcome in a decision.

Mills admitted even she didn't fully understand how to comment in Michigan Public Service Commission proceedings. She said only the wealthy usually have the time and the means to register their opinions.

Grid United CEO Michael Skelly said infrastructure upgrades, renewable additions and carbon capture facilities stand to benefit disadvantaged communities by improving air quality.

Causes for Concern

America's Power CEO Michelle Bloodworth said 80 GW of the nation's 200-GW coal fleet will retire over the next seven years, "putting a lot of pressure" on natural gas infrastructure as a source of fuel-secure dispatchable generation. She said state regulators should slow down the pace of retirements for coal units and let them live their "natural, useful lives" until the grid can secure generation replacements with reliable attributes.

"I don't want to be the angel of death and cast a pall on this discussion…but I think it's important to speak very bluntly about the situation we're in," consultant Bob Gee said.

Gee said gas suppliers desperately need the creation of a gas reliability organization even though it's a "hornet's nest." He said the grid risks outages in the winter and now in the summer as demand grows.

Grid Strategies' Rob Gramlich agreed grid operators are leaning on natural gas more, and more needs to be done to make the supply dependable.

Gramlich credited MISO's 2011 portfolio of Multi-Value transmission projects for keeping the lights on during severe winter weather. He said it's possible to build the grid "bigger than the weather" and thanked MISO for its work on its first, $10 billion long-range transmission plan (LRTP) portfolio. Gramlich also said grid-enhancing technologies and plans for interregional transmission are necessary going forward to safeguard reliability.

MISO COO Clair Moeller said while about 80% of the first LRTP portfolio used existing rights of way or adjacent routes, the second, multibillion-dollar portfolio on greenfield locations will be more difficult to site and build.

"So, buckle up buttercup, this one's going to be hard," he said.

Moeller also said the greater transport capability between organized markets is the most significant change in recent years to avoid load shed events.

"In the old bilateral days, it would take days to move that kind of power," he said.

Moeller said he continues to worry about what the Germans call "dunkelflaute," or multiday periods of overcast skies and little wind. He said storage technology doesn't yet have the capability to cover those prolonged conditions. ■

MISO News

FERC Rejects MISO South Waiver Requests from MISO Accreditation Standard

Commission: Exemptions Would Result in 'Undesirable Consequences'

By Amanda Durish Cook

White Bluff power plant | *Entergy Arkansas*

FERC last week shut down the possibility of Entergy and other smaller MISO South capacity providers bypassing a provision within MISO's availability-based capacity accreditation rules.

In a series of orders, FERC turned down Entergy Arkansas and Mississippi, East Texas Electric Co-op and Arkansas Electric Cooperative Corp. and municipal utilities Conway Corp. of Arkansas, Jonesboro's City Water and Light, and West Memphis Utilities' requests for exemptions of MISO's rule to consider thermal resources that take longer than 24 hours to start up as unavailable, assigning them a zero capacity credit (*ER23-1140*; *ER23-1199*; *ER23-1154*; *ER23-1186*).

In each case, FERC said the parties "failed to demonstrate that the waiver would not result in undesirable consequences, including harm to third parties."

The commission said that while granting the exemptions would raise the resources' accreditation values, it would also reduce MISO's systemwide unforced capacity to seasonal accredited capacity ratio. A reduction in the ratio would decrease the final accreditation values of MISO's other capacity resources, it said. MISO uses the ratio to determine supply ahead of its capacity auction. The RTO *calculated* it incorrectly last year, holding up its first-ever seasonal capacity auction.

This year, FERC similarly denied the Southern Minnesota Municipal Power Agency's and Cleco's requests for waivers of the 24-hour lead time threshold under the new accreditation. (See *FERC Denies Exemption Requests from MISO Accreditation Rule*.)

Entergy requested exemptions for its gas-fired Gerald Andrus Power Plant in Mississippi, its partial ownership interests in Units 1 and 2 of the coal-fired Independence Steam Electric Station in Arkansas and its majority interest in Units 1 and 2 of the coal-fired White Bluff Steam Electric Generating Station in Arkansas. Before the capacity auction, the utility said without the waivers, it risked a supply shortfall in Mississippi. (See *Entergy Seeks Exemptions from MISO Accreditation Rules*.)

MISO's first seasonal capacity auction using the new availability-based accreditation came and went in spring without any capacity shortages. (See *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices*.) ■

PJM News

PJM OC Briefs

Stakeholders Endorse Manual Changes Related to NERC Winter Readiness

The Operating Committee voted during its Aug. 10 meeting to endorse manual *revisions* to conform with essential actions NERC included in a May *cold weather readiness alert*.

PJM's Donnie Bielak said the changes to Manual 13 are essentially verbatim from NERC's language and focus on ensuring that infrastructure used for manual load shedding doesn't overlap with equipment designated for use in underfrequency or undervoltage load shed. The manual changes are slated to go before the Markets and Reliability Committee during its Aug. 24 meeting.

The NERC alert includes eight actions for asset owners and RTOs to take to increase readiness for winter storms. The additional actions include: identifying generators capable of operating at the lowest hourly temperature seen at their locations since 2000; updating balancing authorities' operating plans to account for fuel supply, environmental constraints and availability; and generation owners detailing each facility's cold weather preparedness plan, cold weather critical components and any freeze protection measures that have been implemented on those components prior to the upcoming winter.

Stakeholders encouraged PJM to talk with generation owners about the NERC alert actions that apply to them and their responsibilities.

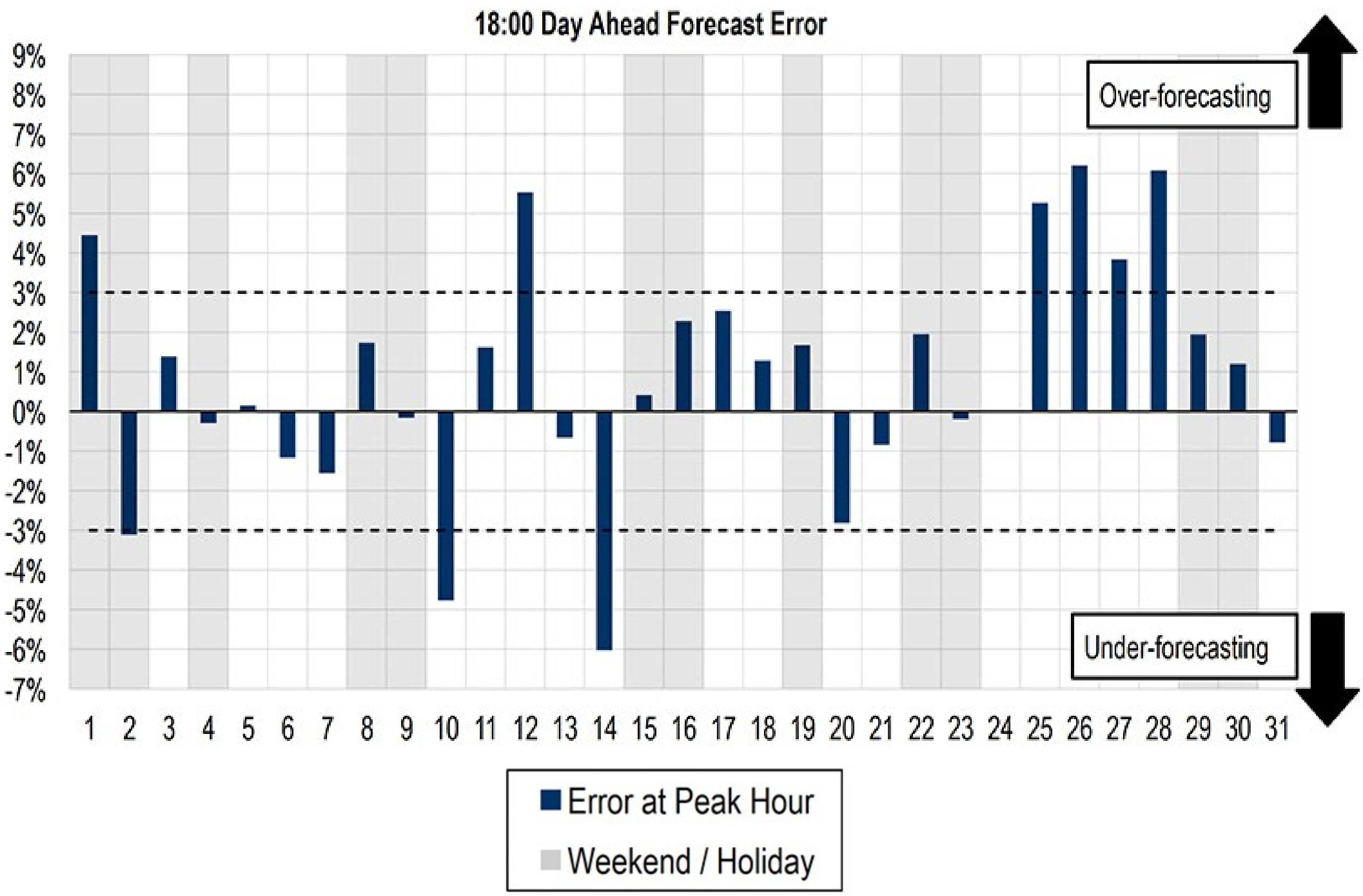
PJM Proposes Synchronized Reserve Deployment Language

PJM brought a quick-fix *issue change*, *problem statement* and a *proposal* to specify that generators should respond to synchronized reserve deployments immediately after receiving an Inter-Control Center Communications Protocol (ICCP) signal or an all-call message. Bielak said outreach to generators about poor reserve response rate has found that many wait until they receive the all-call message even after receiving the ICCP.

"You don't need to wait for that all-call, if you get that ICCP to spin, start deploying your reserves," he said. "The all-call should be more of a confirmation. ... It is an older technology."

The all-call is an automated phone message that can take a few minutes to reach all generators, Bielak said, while the ICCP signal can be transmitted nearly instantly following a reserve deployment.

Reserve performance has been a concern since the response rate declined following an overhaul of the reserve market implemented Oct. 1, 2022. During the July MRC meeting, PJM brought an issue charge and problem statement seeking to open a broader stakeholder process, including the creation of a task



PJM attributed high load forecast errorin July to weather forecasts that proved to be inaccurate as anticipated heat waves were diminished by thunderstorms. | *PJM*

PJM News

force, to investigate several issues and possible solutions related to reserves. (See "PJM Seeks Stakeholder Process on Reserve Certainty," *PJM MRC/MC Briefs: July 26, 2023*.)

July Sees Several Days of High Load Forecast Error

Load forecast error exceeded PJM's 3% goal for several days in July, which PJM attributed to inaccurate weather forecasts. Delivering the *operating metrics report*, PJM's Hong Chen said the 3% figure is an internal goal to measure forecasts against.

PJM overforecast loads July 25-29, when Bielak said a heat wave was expected to bring peaks around 152 to 154 GW. Unexpected thunderstorms contributed to temperatures coming in lower than forecasted, leading to a peak of 147 GW July 27.

"We had up to 10, 15 degrees weather forecast error and that was consistent across the board from all our vendors," PJM's Joseph Mulhern said.

PJM's analysis of the forecast during the heat wave suggests the error came down to weather, rather than load forecast error.

Stakeholders asked PJM to include a narrative explanation and any backcast analyses in future operating metrics reports when forecast error is high.

Bielak said loads were on track to near an "all-time peak" in the last week of July, but the loads didn't materialize. PJM issued hot weather alerts for the entire RTO on the July 26 through 28 and issued a maximum generation alert on the July 27 and 28, triggering a NERC Energy Emergency Alert (EEA) Level 1. The hot weather alerts also defer transmission outages.

PJM issued a maintenance outage recall for the event and had good response from the resources that were offline, which was a small number given it being "peak season," Bielak said. Both generation and transmission performed well through the event, he said.

PJM Proposes Manual Revisions Related to Communication Failures

PJM's Ryan Nice presented proposed *revisions* to Manual 1, which relates to the control center and data exchange requirements, drafted through the document's periodic review. The changes detail when transmission owners must notify PJM that interpersonal communication capabilities have been disrupted.

The new language specifies that communication can include several forms of contact, including cell phones, satellite or radio, and that a notification of failure has to be made only when all modes have failed.

PJM Brings Quick Fix Issue on Data Sharing

PJM presented a quick fix *issue charge*, *problem statement* and proposed *manual changes* to create a carve out from the requirement that PJM provide five days' notice before providing confidential information to NERC, reliability coordinators, transmission operators and similar groups.

The problem statement says PJM regularly provides such information and has found the notification requirement can be inefficient and burdensome in certain instances. The proposed manual language would create an exception for data transmitted during a NERC audit or investigation into whether PJM is in compliance with reliability standards and when using tools created by regional entities, such as NERC's Generator Availability Data System (GADS).

PJM Details Cybersecurity Threats

PJM Chief Information Security Officer Steve McElwee *said* new cybersecurity threats are rising, including the use of artificial intelligence to create targeted messages designed to trick targets into divulging sensitive information and groups ransoming data.

An offshoot of the language learning model ChatGPT has been created to bypass safeguards preventing the model from being used to create "phishing" emails aimed at stealing information, and McElwee highlighted recent Congressional testimony about the threat Chinese artificial intelligence advancements present the American electric industry.

McElwee said a "critical infrastructure company" has been targeted by an exploit found in the software Citrix, which allowed data to be collected on targeted systems. The Cybersecurity and Infrastructure Security Agency (CISA) has released an *advisory* recommending that Citrix users evaluate their systems for potential compromise and apply patches released by the developer to resolve the issue.

Critical Load Verification Process to Begin Shortly

PJM is preparing to initiate the critical load verification step in its black start request for proposal process. Starting in late August or early September, generators will be required to validate the amount of existing critical load they possess or submit data for new generators.

PJM's Dan Bennett *said* critical loads are the components that will require power from the grid to restart a generator as black start resources "crank" the grid after a blackout. The restoration process focuses on generators with a start time of four hours or less. He said critical load includes equipment such as electric gas compressors and nuclear units' shutdown, safety and cooling systems.

The parameters PJM will be looking for includes the energy requirements of the critical load, motor sizing and transformer parameters. The analysis also will look at the cranking paths to ensure the transmission grid can route power from black start units to generators being restarted.

PJM and IMM Plan Joint Filing on Real Time Values

PJM and the Independent Market Monitor plan to make a joint filing asking that FERC act on its real time values proposal made in July 2021. The filing was made in the commission's pending order to show cause stemming from a concern that PJM's tariff may not be just and reasonable due to uncertainty around what happens if a generator cannot meet its unit-specific parameters in real time (*EL21-78*).

PJM's Lauren Strella Wahba said PJM's proposal would allow real time values to be submitted only for actual physical unit limitations or those outside management control. Real time values would be required to be submitted after the close of the day ahead market.

The order to show cause stated that PJM's tariff may allow generators to avoid market power mitigation by submitting offers that increase the likelihood of market-based, rather than parameter-limited, offers are selected. (See *FERC Issues Show Cause Order on PJM Parameter Limited Offers*.)

"Sellers may be able to structure their market-based parameter-limited offer strategically to ensure that PJM chooses the market-based offer, which is not subject to parameter limits," the commission said. "This undermines the purpose of parameter-limited offers, which is to ensure sellers are not able to exercise market power through the use of inflexible operating parameters."

The order to show cause came after the commission rejected PJM's proposal to allow sellers to change their unit-specific parameter limits in real time in May 2021. ■

— Devin Leith-Yessian

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Endorse RRS Load Model

VALLEY FORGE, Pa. — The PJM Planning Committee last week endorsed the load model *recommended* by the RTO for calculating the load forecast for the 2023 reserve requirement study (RRS).

The selected distribution, derived from data from 2013 through 2019, has a more conservative estimation of future loads than the model used in the 2022 study, with loads being higher in most percentiles.

The study will set the installed reserve margin and forecast pool requirement for the 2027/28 delivery year and inform any modifications to the previous three years' values.

Alongside the Probabilistic Reliability Index Study Model (PRISM) program, PJM will use software developed for the hourly loss-of-load modeling used for effective load-carrying capability (ELCC) studies in this year's RRS.

PJM says the ELCC software has the potential to produce better results and will generate two sets of data, which will be presented to stakeholders when the study is complete for endorsement of one set of outcomes. (See "Reliability Requirement Study to Use New Software," *PJM PC/TEAC Briefs: May. 9, 2023*.)

The load model selection process is required only for the PRISM software, which requires normal distributions of data, whereas the PJM forecast data are empirical. The ELCC process models the monthly peak load uncertainty by deriving load scenarios and frequency weight for each delivery year between 2012 and 2021.

The top three performing load models all project PJM's peak overlapping with the peak for the "World," defined as MISO, NYISO, TVA and VACAR. The RTO recommends that the World peak be moved to a different week in July to avoid the overlap, which it historically has found unlikely and would lead to a decreased capacity benefit of ties (CBOT) value.

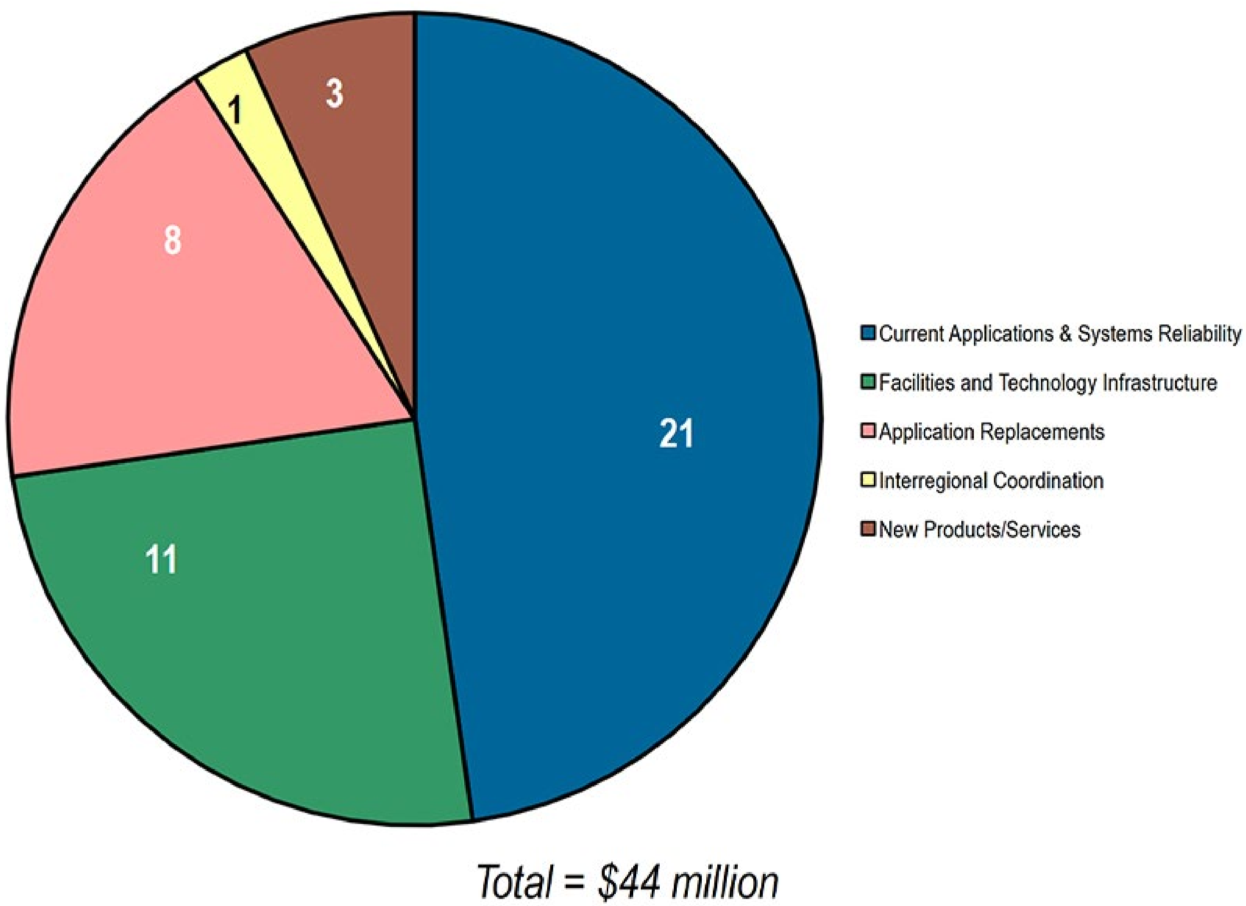
PJM's Patricio Rocha Garrido said in the past 24 years, the World and PJM have not peaked on the same day in just over half those years. The PRISM software used to conduct the load model analysis treats each day as a five-day week, which would compound the impact a coincident peak would have in the data.

PJM Presents Preliminary Capital Budget

PJM *presented* a $44 million capital budget to stakeholders, a $2 million increase over the amount it projects to spend in the 2023 fiscal year. The preliminary budget is dominated by the cost of current applications and systems reliability, facilities and technology infrastructure and application replacements.

Though the $44 million ask is an increase over recent years, PJM's James Snow said the RTO remains within the $45 million range it expected to spend.

Spending on applications makes up nearly half the budget at $21 million, which includes upgrades to PJM's Dispatcher Application



PJM presented a preliminary $44 million capital budget proposal to the Planning Committee on August 8. | *PJM*

PJM News

and Reporting Tool (eDART) system, improvements to credit or risk applications and cybersecurity. Facilities and technology spending would sit at $11 million and include replacement of backup generators at the control center and server upgrades.

The $8 million in proposed application replacements includes spending on the Next Generation Markets Systems (nGEM) project being undertaken with several other RTOs to build a new market clearing engine and related software.

Spending on new products and services would be $3 million, while $1 million would be spent on interregional coordination.

Migration of eDART Accounts to New Platform Underway

PJM began the process of working with members to transition from managing their accounts through eDART to its Account Manager software. The migration of the 7,443 accounts in eDART started on July 25 and will continue through Dec. 13.

PJM's Maria Baptiste *recommended* that users begin transitioning as quickly as possible to give themselves time to work through any issues that may arise. The Account Manager dashboard can be used to create new user accounts, reset passwords, unlock accounts and grant or terminate eDART account access.

Transmission Expansion Advisory Committee

AEP Proposes $202 Million Rebuild of 345-kV Line

American Electric Power *proposed* rebuilding its 51.8 mile, 345-kV Desoto-Sorenson line, telling the Transmission Expansion Advisory Committee last week that the majority of the lattice structures and conductor on the line are more than 70 years old. The utility proposed rebuilding the line in a double circuit configuration at a $202.4 million cost, including new structure entrances at the Sorenson, Keystone and Desoto substations.

The line has experienced 22 momentary outages and 12 permanent outages since 2014. AEP has found that the paper-expanded conductor installed on it is difficult to splice during repairs because of limited replacement materials.

AEP also evaluated rebuilding the line as a single circuit, but it determined that because of the number of generators seeking to interconnect on both sides of the line, as well as its status as the only transmission connecting the Fort Wayne grid to the 345-kV Tanners Creek hub, a double circuit would be more appropriate. The cost of a single circuit rebuild was estimated at $187.4 million.

FirstEnergy Presents Data Center Interconnection Projects

FirstEnergy *proposed* $27 million in upgrades to meet a projected 336 MW in data center load growth near its proposed 230-kV Sage substation.

The proposal includes a $1.5 million expansion of the substation, including installing three additional 230-kV circuit breakers, two new transformers and two 34.5-kV buses. The 138-kV Bartonville-Meadow Brook line would also be upgraded with an additional wave trap and revised relay settings for $700,000.

The third phase of the project, estimated at $25 million, would add nine additional breakers to the substation, bringing the total to 15, and terminate the 230-kV Doubs-Eastalco line at Sage. The substation would also be looped into the 230-kV Doubs-Lime Kiln line.

PJM's Sami Abdulsalam said the data center load was identified in the 2022 Regional Transmission Expansion Plan (RTEP) Window 3, which is in the proposal selection phase, and the proposal addresses the interconnection requirements for the load.

Philip Sussler, of the Maryland Office of People's Counsel, asked if there was any transmission headroom available from the deactivation of the Eastalco Aluminum plant, which used about 300 MW prior to its retirement in 2010.

FirstEnergy's Larre Hozempa said some of that transmission capability has been consumed by load growth over the intervening decade and the new data center load is expected to be significantly larger than the plant's. The load included in Window 3 was about 1,300 MW, with 900 MW already under contract.

Update on RTEP Windows

Abdulsalam also *presented* an update on the 2022 RTEP Window 3 and the first window of the 2023 RTEP, which opened on July 24 and is set to close on Sept. 25. (See "2023 RTEP Window 1 to Open this Month; 2022 RTEP Window 3 Selections in September," *PJM PC/TEAC Briefs: July 11, 2023*.)

Window 3 closed on May 31 after receiving 72 proposals from 10 entities, and PJM has completed the individual proposal screening and planning evaluation steps. It is now conducting proposal scenario evaluations. In developing and analyzing dozens of scenarios, PJM looks at the full proposals made and modifications to them, and combines elements to create mix-and-matched variants.

Abdulsalam said the window had an atypically low rate of cost-containment commitments, signaling that developers believe there is higher risk associated with the projects and that it may be harder to ensure that cost estimates remain accurate.

Ranking of the scenarios will include scalability to address future needs, use of existing rights of way, cost evaluation and avoiding redundant capital investment. Abdulsalam said part of the analysis will include looking at other proposed projects outside the window and evaluating if they can be modified or synergized with the RTEP to reduce costs. He said the $786 million in transmission upgrades associated with the deactivation of the 1,295-MW Brandon Shores coal generator near Baltimore is one such project.

Some of the proposals that were focused on addressing the 2027 model needs do not appear to be expandable to address needs expected in the following year, Abdulsalam said. Analysis of the 2028 model also shows more grid reinforcements needed in the eastern and southern Dominion regions.

PJM is aiming to hold a special TEAC meeting in October to present the window evaluation results, followed by asking the Board of Managers for approval in December. ■

— Devin Leith-Yessian

PJM News

PJM MIC Briefs

Stakeholders Endorse Proposal on Co-located Load

VALLEY FORGE, Pa. — The PJM Market Implementation Committee voted to endorse one of several *packages* to flesh out the rules around loads seeking to receive their power from behind the meter of a generator. (See "Vote on Rules for Generation with Co-located Load Deferred," *PJM MIC Briefs: July 12, 2023.*)

A 51.2% majority of stakeholders supported Exelon's proposal for co-located loads not considered to be receiving service from the wholesale grid, passing over three competing proposals. None of the four proposals for co-located loads receiving grid service received majority support.

The Exelon proposal would permit a generator to retain its capacity interconnection rights (CIRs) for the share of its output supplied to the co-located load, so long as that load curtails within 10 minutes of PJM calling on the generator to supply that capacity to the grid.

For co-located configurations to be considered to not be receiving grid service, they would need to be designed to ensure that they're exclusively supplied by the corresponding generator and disconnected whenever they're not being served by the generator.

The proposal would consider the generator to be a load-serving entity for the co-located load and levy all relevant load-serving entity (LSE) credits and charges.

The approach of allowing co-located load to not be considered receiving grid service — but assigning some of the charges a wholesale customer would be assessed to the generator — has raised stakeholder questions, with some arguing it could muddy the waters of state and federal jurisdiction.

PJM's Tim Horger said the current rules for generators receiving grid service remain unclear without a package approved addressing those configurations, and he plans to examine the Exelon package for ways to discuss additional changes.

"I think we probably still want to do that, but we also want to take into account the Exelon package that was approved," he said. "To be clear, we do have rules in place now and we are following them."

Lynn Horning of American Municipal Power (AMP) said any approach PJM plans to take on co-located load with grid service should be clear when stakeholders make their final endorsement vote on the Exelon package.

MIC Rejects Reactive Power Compensation Proposals

Stakeholders rejected four *proposals* to revise the compensation structure for generators providing reactive power service and voted to sunset the Reactive Power Compensation Task Force (RPCTF). Generator owners are required to submit a FERC filing for each facility providing the service to receive compensation, which creates administrative burden and lacks a standardized approach. (See "First Read on Reactive Power Compensation Proposals," *PJM MIC Briefs: July 12, 2023.*)

The clean energy coalition (CEC) proposal, formed by a group of renewable developers, received the most support at 62.2% when compared to the other three packages. But it didn't hold onto that support when compared to the status quo and failed to pass at 44.3% support.

The CEC package would create a cost-of-service structure with a flat rate based on the methodology FERC uses to evaluate reactive filings and would require testing to validate that generators receiving compensation are able to provide the service.

The PJM proposal would have determined each generator's reactive capability, measured in MVAR, and compensated them monthly. Synchronous and storage resources would have been compensated based on their availability in the prior month.

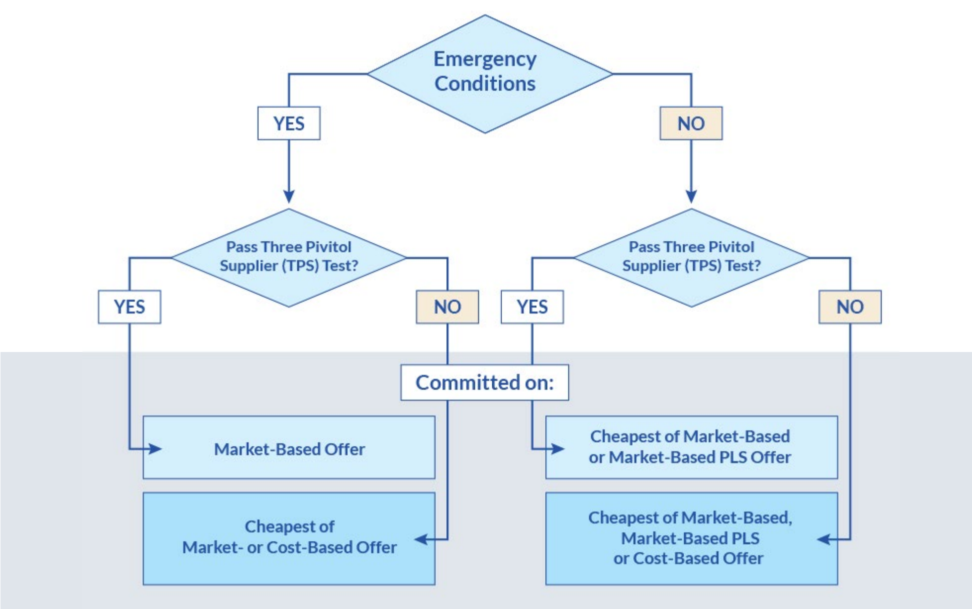
The Independent Market Monitor made two proposals, the first of which would have eliminated compensation outside of existing markets on the basis that all generators are required to provide reactive service as part of their interconnection service agreement (ISA).

The Monitor's second would have used a flat rate structure based on demonstrated capability, similar to PJM's proposal, but would have phased out compensation.

The proposals would have affected only new generators or facilities entering new compensation agreements, with the task force's scope precluding changing existing reactive rates. The MIC voted down a proposal to expand the task force's scope to include existing service rates last month. (See "Stakeholders Reject Proposal to Expand Reactive Power Task Force Scope," *PJM MIC Briefs: June 7, 2023.*)

Danielle Croop, facilitator for PJM's Reactor Power Compensation Task Force, said in the absence of a main motion to move to the Markets and Reliability Committee, stakeholders could decide to continue deliberations at the task force, move discussion to the MIC or sunset the task force and close the issue.

David "Scarp" Scarpignato of Calpine said it's significant that none of the proposals gained support over the reigning rules and given that the task force began its work two years ago it's unlikely more discussion would



A PJM graphic shows the structure for offers being evaluated by the market clearing engine. | *PJM*

PJM News

yield new proposals.

"It doesn't look to me like it's a good idea to go back to the task force. I don't think it's a matter of whittling down the existing proposals to better proposals, I think people like the status quo," he said.

Scarp motioned to sunset the task force, which was approved by acclamation without objection.

First Reads on Proposals Addressing Multi-schedule Modeling in MCE

Package sponsors gave first reads of three *proposals* aimed at addressing the expected performance impact of implementing multi-schedule modeling in the rebuild of the market clearing engine (MCE). (See "Merged IMM-PJM Issue Charge on Multi-schedule Modeling Endorsed," *PJM MIC Briefs: March 8, 2023*.)

The discussion stems from a finding that introducing the enhanced combined cycle (ECC) model and energy storage resource (ESR) and hybrid model into the Next Generation Markets (nGEM) overhaul of the engine would cause the amount of time it takes for PJM to determine what resources will clear in the day ahead market to become impractical.

For combined cycle generators, the number of different configurations they can operate in, with varying numbers of turbines paired with heat recovery steam generators (HRSGs) and multiple offers for each configuration, multi-schedule modeling could lead to an exponential increase in MCE computation times.

PJM's *Package A* would address the issue by creating a formula that would select one offer resulting in the lowest total dispatch cost to be modeled in the MCE.

PJM's Keyur Patel said the schedule selection built into the MCE is the most optimal approach, but he does not see any way of getting the benefits of including the new models into the engine without some compromises. A joint PJM and GT Power proposal would use the Package A approach, but consider only cost-based offers for resources that fail the three-pivotal-supplier (TPS) test. Price-based offers would be used for resources that pass the test, aside from price-based parameter-limited schedule (PLS) offers being used for capacity resources under emergency conditions.

The Monitor's *proposals* could combine the lowest offer points and most flexible parameters from resources price and cost based offers under certain scenarios, impose offer capping and parameter limits to all resources that fail the TPS test and apply parameter limits to capacity resources during emergencies

Deputy Monitor Catherine Tyler said there are market power concerns in the MCE which allow resources to inflate LMPs by using high markups and to extract uplift using inflexible parameters, both of which would be made worse by PJM's proposal. She said that parameters other than minimum run time aren't considered under PJM's approach.

Endorsement of the proposals is scheduled for the Sept. 6 MIC meeting. Customized Energy Solutions' Carl Johnson said deciding between the packages likely will remain difficult for stakeholders who aren't as familiar with offer structures.

"For those of us who aren't really in the weeds on this, this is a really difficult choice to make," he said.

Voltus Brings Economic Demand Response Parameter Issue Charge

Voltus *presented* an *issue charge* and *problem statement* making the case that demand response resources lack the parameters other generators can include in their offers, limiting the consumers able to participate as an economic resource.

David Aitoro of Voltus said DR now can be dispatched for a single five-minute interval, then be curtailed only to be called on again in the third interval. For many DR participants, that may not match their curtailment capabilities and is not in line with parameters other generation resources can include in their offers, he said.

He also argued that many consumers who could curtail air conditioning systems could do so for one to three hours without a major impact to building temperatures, but there's no capability to structure an offer to reflect that.

"It's really DR that's getting left out in the cold here," Aitoro said.

Several stakeholders discussed the scope of the issue charge and how economic DR in the energy market relates to DR entering the capacity market. Aitoro said Voltus' intent is to focus on the energy market, which could include resources that also offer into the capacity market.

PJM's Peter Langbein said there's around 8 GW of DR in the capacity market with corresponding energy market offers, most of which are in excess of $1,000/MWh. Economic DR also can offer separate energy-only offers, with about 2 GW doing so.

Scarpignato said generators are required to enter their most flexible parameters in their offers and those Voltus is seeking to include appear to reflect desires rather than true capability.

Exelon's Alex Stern noted that discussion held at the Distributed Resources Subcommittee (DISRS) on the issue charge and problem statement was raised during the July MIC meeting, with stakeholders questioning if the topic fit into the group's scope or if it should be discussed elsewhere. (See "Stakeholders Question Scope of Distributed Resources Subcommittee," *PJM MIC Briefs: July 12, 2023*.)

MIC Facilitator Foluso Afelumo said the scope and proper group to host the discussion are the primary issues to be ironed out before a vote.

Stakeholders Discuss Proposals to Include Local Factors in Net CONE

Paul Sotkiewicz, president of E-Cubed Policy Associates, presented a second *proposal* to create rules for incorporating local considerations that could impact generators' net cost of new entry (CONE), such as local or state regulations or legislation. (See "Discussion on Local Considerations for Net CONE," *PJM MIC Briefs: March 8, 2023*.)

The package would create a fifth CONE area for the Commonwealth Edison region, which Sotkiewicz has argued will see significant impacts to generator lifespans under the Illinois Climate and Equitable Jobs Act (CEJA). PJM also automatically would create new CONE areas for any regions where new local factors cause a reduction in asset lifespan or set emissions limits that "imply a reference resource with different technology" than the current resource net CONE is based on.

Sotkiewicz said the proposal would capture the potential for hydrogen fuel blending or carbon sequestration requirements to increase operating and maintenance costs or introduce issues with the asset life.

If the reference resource were to remain a combined cycle generator at a point when those resources are being required to blend hydrogen, he said there would be a need to incorporate that in the energy and ancillary services (E&AS) offset and update its asset lifespan more regularly.

The PJM package would also create a fifth CONE area for the ComEd region but does not create any provisions for the future addition of new areas. ■

— Devin Leith-Yessian

SPP News

FERC Grants Co-ops' Complaint Against PSCo

Co-ops Say they were Charged Millions for Extra Fuel Costs

By Tom Kleckner

FERC last week granted one of three claims against Public Service Company of Colorado (PSCo) in response to cooperatives' complaints that they were charged $17.5 million in excessive gas costs during Winter Storm Uri in 2021 (*EL23-21*).

The commission said four PSCo customers (CORE Electric Cooperative, Grand Valley Rural Power Lines, Holy Cross Electric Association and Yampa Valley Electric Association) were able to prove they are entitled to review a baseload contract under the utility's fuel protocols. It directed PSCo to make the contract available to the complainants, subject to a protective order.

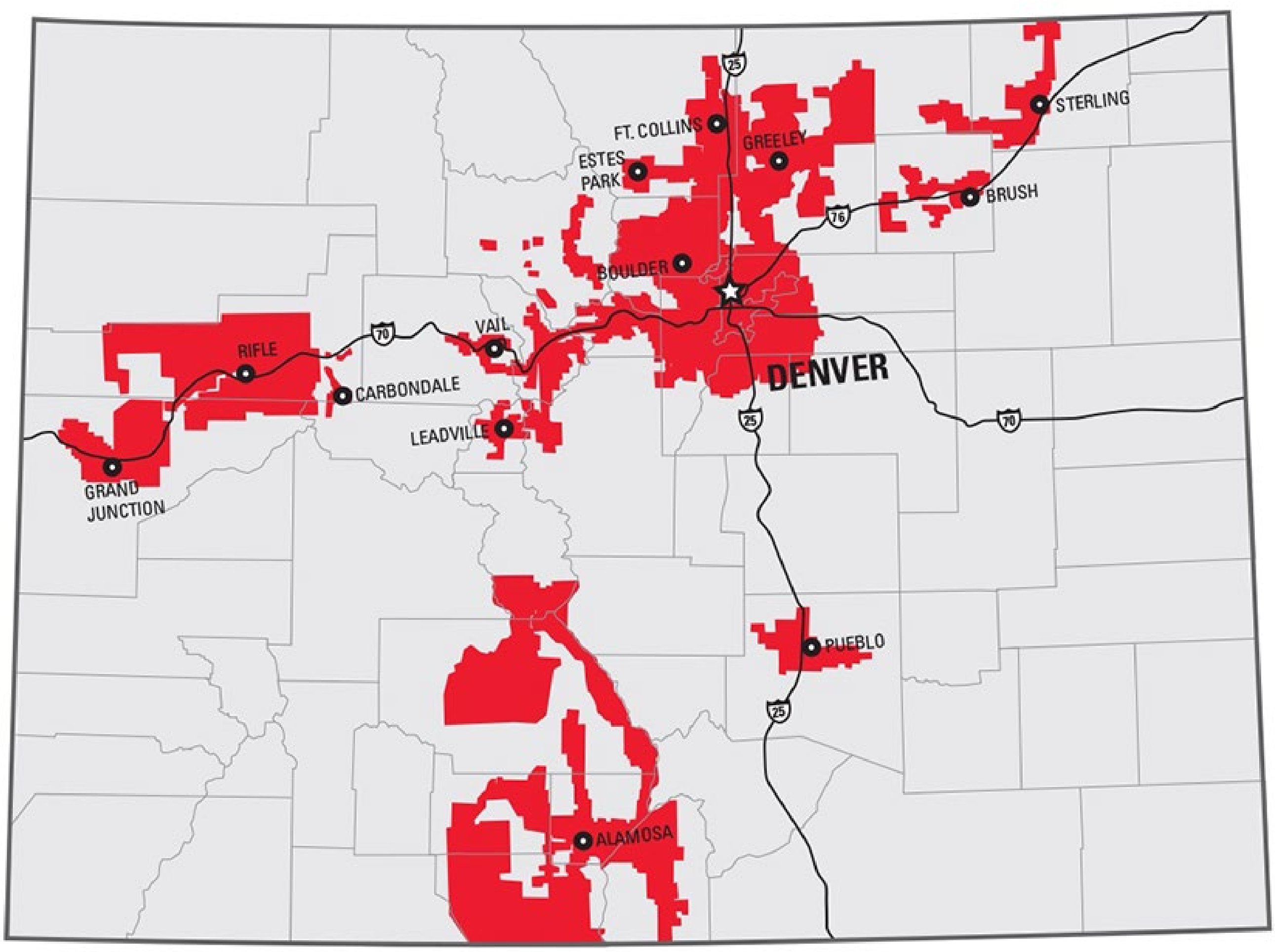
The cooperatives said they were charged $17.5 million for extra fuel costs during the storm.

The utility's fuel protocols provide that PSCo will make available to any wholesale fuel adjustment clause customer "books and records" related to the clause's provisions and protocols. The Xcel Energy subsidiary argued the term "books and records" does not include the baseload contracts because the contracts are not the actual inputs for the fuel costs that are calculated and charged to the cooperatives under the fuel adjustment clause.

PSCo contended that the invoiced amounts charged under the baseload contracts, which it had already turned over to the cooperatives, were relevant because the information is necessary to understand how the charges were calculated. FERC found the argument to be unpersuasive, saying the utility did not cite any fuel protocol language indicating that "books and records" is limited only to "fuel cost inputs."

The commission denied two other complaints by the cooperatives: that PSCo "imprudently" planned for its natural gas reserves and passed on excess costs from spot market purchases in February 2021 and that it acted imprudently and in a preferential manner by selling excess gas to an affiliate during the storm. FERC said the complainants had not presented sufficient evidence to meet their initial burden for those claims.

The commission also denied without prejudice the complainants' request for relief from a Dec. 31, 2022, tariff deadline to raise questions concerning the fuel adjustment clause charges. They alleged PSCo violated its filed rate by withholding information, negating a further challenge to the charges, but FERC found the request to be "premature at this time." ■



Public Service Company of Colorado's footprint | *U.S. SEC*

SPP News

SPP Markets+ Stakeholders Begin Tariff's Development

'RTO-light' Market's Success Hinges on Participants, Staff Partnership

By Tom Kleckner

From right: Snohomish PUD's Joe Fina, NV Energy's Carolyn Barbash and Powerex's Mark Holman take notes during the discussion. | *© RTO Insider LLC*

PORTLAND, Ore. — Potential SPP Markets+ participants last week endorsed the first pieces of the day-ahead market's tariff, acquiring a taste of the grid operator's stakeholder process at the same time.

The core of that process is a focus on reaching consensus. It is ideally driven by stakeholders with SPP staff support, with a final agreement that satisfies a solid majority of members.

SPP Director Steve Wright, who chairs the three-person Interim Markets+ Independent Panel (IMIP) responsible for the market's development, complimented the Markets+ Participant Executive Committee (MPEC) and its working groups and task forces for quickly adapting to the stakeholder process.

"I'm really impressed with the way that you've embraced democracy. Democracy can be messy, and it can be hard, but that's what we're doing here," Wright said during the conclusion of the MPEC's Aug. 8-9 meeting. "We love to see the participation; the way the voting structure is working; the way that motions create clarity around what it is that's on the table, and then being able to move forward."

Russ Mantifel, Bonneville Power Administration | *© RTO Insider LLC*

John Cupparo, who along with fellow director Liz Moore fills out the IMIP, recalled the tariff discussion led by Bonneville Power Authority's Russ Mantifel. Standing isolated in front of the MPEC for almost an hour and a half, Mantifel described how he was able to "flex the democratic muscle" — flexing his own muscles for emphasis — during workgroup discussions and gain confidence in the recommendations and motions that came forward.

"I thought it was a very important point in terms of the confidence that it gave him and hopefully that group in terms of how the process works and what we're building," Cupparo said. "I'm hopeful that that confidence propagates and continues to propagate among the workgroups."

Cupparo also noted the workgroup updates that filled the agenda included "natural" references to SPP staff and the SPP Market Monitoring Unit.

"It suggests that there's a growing partnership, which is very important in this process, not only now but for the future," he said.

With CAISO having about an eight-year head start in developing a Western RTO, and a group of utility commissioners from the West calling for an independent grid based on CAISO's operating framework, that partnership could be key for SPP's plans to offer "RTO-light" services that include day-ahead and real-time unit commitment and dispatch. (See *In Contest for the West, Markets+ Gathers Momentum — and Skeptics*.)

SPP plans to complete this second phase of Markets+'s development by filing a completed tariff with FERC early next year. The IMIP and MPEC are expected to sign off on the tariff language in December, with the RTO's Board of Directors taking up a vote in January.

Wright reminded Markets+ stakeholders that once the tariff is filed, potential participants will have to decide whether to proceed with costly systems development or wait for FERC's approval. He urged further discussion on that next step during the MPEC's upcoming virtual and *in-person* meetings.

"The SPP staff needs this guidance because this is an allocation-of-resources issue. Folks have got to know what their work plans are going to look like, and so we need some sense of what the market participants are thinking," he said. "I know there's a bit of a chicken-and-egg issue here. It's, 'Well, I need to know for sure the tariff is proceeding before I'm prepared to commit dollars.' On the other hand, if we wait until everything is final, then it will have a significant impact on the overall scheduling and the go-live date for a Markets+ market."

MPEC Chair Laura Trolese, with The Energy Authority, said that while the program is on track, there is "some potential risk" of the schedule slipping over approval of the "boilerplate" tariff language.

"The working groups have been a little hesitant to approve boilerplate language," she said.

SPP News

"There's been quite a bit of education and level-setting and bringing everyone up to speed."

Trolese said stakeholders have reaffirmed moving forward with the boilerplate language, with an understanding that the final tariff will include changes to accommodate issues unique to the West.

Carrie Simpson, SPP's director of Western services development and MPEC's staff secretary, pointed out that the boilerplate tariff language the stakeholder groups have started with is limited to principles and concepts outlined in the *Markets+ service offering* that participants agreed to last year.

"It's the SPP existing market design, and the SPP market design is largely based on MISO's market design, which is largely based on PJM's market design. These are best practices," she said.

IMIP Approves Virtuals' Delay

The IMIP agreed with MPEC's recommendation to delay the implementation of the price convergence financial product, or virtuals, by six months after the market goes live and with built-in circuit-breakers.

Virtuals are proposals to buy and/or sell energy at a settlement location for a specific time period in the day-ahead market. They were created to foster price convergence between the day-ahead and real-time markets and add liquidity. Settlements are based on the difference between the day-ahead and real-time price.

Stakeholders reasoned that virtuals, or the lack thereof, will not affect must-offer obligations. In addition, Markets+ boundary interface settlement locations are not eligible for virtuals. SPP will assess the settlement locations within a year of the virtuals becoming binding.

"My impression is that it was a rather robust conversation at the workgroup level, and it demonstrated that there's differing points of views and there's a way to get to a compromise or a consensus," Cupparo told the MPEC. "That's at the heart of what we do every day within the SPP way of life. That's the model. That's how it works."

SPP's Carrie Simpson (left) and MPEC Chair Laura Trolese confer before the meeting. | © RTO Insider LLC

It was the only item the IMIP took up for consideration, saying it wanted to avoid interfering in the developmental work.

"There should be no sense of a signal that we have concerns about what's going on. We're trying to make sure that we're not micromanaging you," Cupparo told the MPEC.

The MPEC did endorse tariff language governing day-ahead and operating day activities, and LMPs and market clearing prices (MCPs). Committee members agreed a draft of language on scarcity pricing's effect on LMPs and MCPs should be reviewed and brought back to the MPEC.

GHG Issue: 'Emissions Leakage'

Clare Breidenich, Western Power Trading Forum | © RTO Insider LLC

Clare Breidenich, who co-chairs the Markets+ Greenhouse Gas Task Force (MGHGTF), said the team is currently reviewing a draft and providing feedback on its tariff language, which is on track to be approved in October.

The task force's primary objective is to develop a market solution, best practices, rules and protocols that support the Northwest's only cap-and-trade program, that of Washington state, Breidenich told the MPEC.

"That program is already in place. Entities are incurring carbon obligations as of this year," she said. "The live Markets+ would need to accommodate that program from the get-go."

Labeled as *cap-and-invest* in Washington, the program began earlier this year with the Department of Ecology conducting the first two quarterly auctions. The department had to put up more than 1 million carbon allowances to help keep emitters' costs in check after the May auction cleared at an unexpectedly high price ($56.10/allowance). (See *Wash. Auctions Reserve Carbon Allowances to Relieve Price Pressure*.)

Breidenich, who specializes in carbon policy, markets and regulations for the Western Power Trading Forum, said the task force is focusing on megawatt re-designation, or emissions leakage. This occurs when a change in market dispatch to accommodate the Washington program reduces emissions associated with generation serving load in the state but increases the market footprint's emissions.

"The bulk of our work within the task force is trying to narrow down the definition of this problem to solve it," she said.

The task force is evaluating the need for a multi-solve solution in the market-clearing engine and developing other options to minimize leakage, Breidenich said. The intention is to "identify what megawatts from what resources are eligible to be attributed to Washington state," she said.

"Washington state is my bread and butter at this moment," Breidenich said, noting that there is not perfect solution to the leakage problem.

"Anybody who has looked at this problem for any length of time realizes it pretty much is intractable. It is not caused by a deficiency in today's market. It is not caused by a deficiency in the state program," she said. "It is caused solely by the fact that you have a greenhouse gas pricing program in a limited geographic area with a much broader market footprint, full stop."

"The only way you can fundamentally completely solve the leakage problem is if every jurisdiction within the market adopted a pricing program. We shouldn't get too committed to the perfect solution because we won't find it," Breidenich added.

Trolese pointed out that with carbon allowances clearing at more than $60, it amounts to a $30 adder to a participant's energy prices.

"It's a significant impact to market dispatch ... that adds to the complexity," she said. "There's no perfect solution, but every imperfect solution has some pretty serious impacts to the market and different market participants."

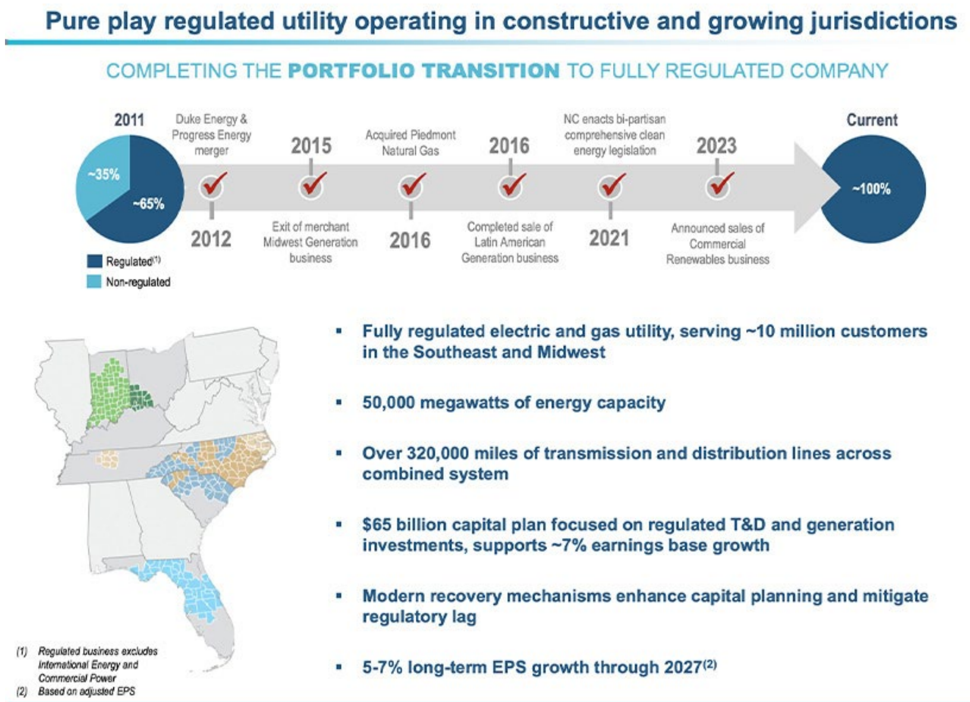
Several other western states have adopted greenhouse gas-reduction targets or have clean energy programs that don't rely on pricing elements in their dispatch. Most of these efforts have a 2030 target before they become binding, allowing the task force additional time to determine how to incorporate them into the tariff.

"We've heard very clearly from regulators and market participants in those states that these are important, and we need to think about how the market solution can address these programs," Breidenich said. "We are starting that work, but it's going to be in a longer time frame than meeting the pricing program details." ■

Company News

Duke Energy Quarterly Call Focuses on Long-term 'Organic' Growth Plans

by James Downing



A slide Duke Energy produced showing major developments in its business to a fully regulated firm focused on the energy transition. | *Duke Energy*

Duke Energy last week reported a second quarter loss of 32 cents/share in the second quarter, attributed to mild weather and an impairment of $1 billion from the sale of its commercial renewable business.

The firm's core market of the Carolinas saw the mildest January and February in the past 30 years, while May and June were mild enough to make the top five, CEO Lynn Good told investors on a conference call. The mild weather was enough to cut earnings by 30 cents/share, she said.

"We've had an early look at July, and as you would expect July weather, it's positive, consistent with the trend across the U.S., and August and September are in front of us," Good said. "With our largest quarter ahead, we are reaffirming our guidance range for 2023."

The firm sold off its commercial renewables business earlier this year, with deals expected to close by the end of the year. (See *Duke Energy Sells Distributed Renewable Business to Arclight*.)

"We're a wholly regulated company operating in constructive and growing jurisdictions with a wealth of clean energy investments driving growth for years to come," Good said. "The regulatory constructs in our states have also meaningfully improved over this time, including landmark bipartisan energy legislation passed in North Carolina in 2021."

Now the firm's sole focus is on its regulated businesses and its ongoing work on the clean energy transition, she added.

"Our energy transition in the Carolinas remains a top strategic priority, and we're working diligently on updated resource plans to be filed with the Public Service Commission of South Carolina and the North Carolina Utilities Commission in mid-August," Good said. "Similar to previous filings, the plans are based on significant stakeholder engagement and will outline multiple portfolios, each of which preserve affordability and reliability while transitioning to cleaner energy resources."

The plans will include benefits from the Inflation Reduction Act and will reflect healthy load growth in the Carolinas as they continue to see population growth because of migration, she added.

Duke has been adding solar to its generation mix with a procurement in North Carolina finalized recently that will see 1,000 MW added to the grid by 2027 and another approved recently by the NCUC that will add 1,400 MW in the coming years. In Florida, the firm added 300 MW of solar this year and now operates 1,200 MW in the state, with plans to add 300 MW per year there going forward.

"In Kentucky, we've partnered with Amazon to install a 2-MW solar plant on top of their fulfillment center in Northern Kentucky, the largest rooftop solar site in the state," Good said. "This partnership supports the carbon-reduction goals of both Duke Energy and Amazon."

The firm has a clear strategy focused on "organic" growth of its regulated businesses, said Good.

Some of the analysts on the call asked about "inorganic" growth, with one asking if Duke was interested in buying Dominion Energy's Public Service Company of North Carolina subsidiary. Dominion has sold off some of its other non-core assets recently.

Good declined to comment on "another company's process," but earlier in the call she explained her thoughts on mergers and acquisitions generally.

"Our sole focus is on this organic plan that's in front of us," Good said. "And, so, any idea about M&A has to beat what we have in front of us, and it is an increasingly high hurdle because of the confidence we have in our plan." ■

Company Briefs

Eversource Leaves the American Gas Association

Eversource Energy has parted ways with the American Gas Association as part of a broader strategic effort to prioritize "decarbonization."

In describing the company's decision to leave the association, Eversource spokesperson Chris McKinnon said, "We're taking an all-encompassing approach to explore innovative ways to decarbonize the natural gas system."

Eversource's departure appears to mark the first time a major utility has left the gas trade group over diverging climate agendas.

More: *WBUR*

Proterra Files for Bankruptcy Protection

Proterra, the largest U.S. electric bus maker, filed for Chapter 11 bankruptcy protection on Aug. 7.

The company said it plans to continue business operations as it pursues a restructuring "to strengthen its financial position through a recapitalization or going-concern sale."

Proterra, founded in 2004, has sold about 1,300 buses to more than 130 transit agencies in the U.S. and Canada. It also supplies drivetrains and batteries for other bus and transit manufacturers.

More: *Canary Media*

VinFast to Build Vehicle, Battery Factory in NC

Vietnamese carmaker VinFast last week announced that it will build its first foreign factory, a $4 billion vehicle and battery plant, on an undeveloped site in Eastern Chatham County in North Carolina.

As recently as 2020, the company exclusively sold gas-powered cars in Vietnam. Now, its objective is to deliver hundreds of thousands of electric SUVs to drivers worldwide.

VinFast hopes to open the facility within two years.

More: *The News & Observer*

Federal Briefs

4th Circuit Dismisses Enviro Cases Against Mountain Valley Pipeline

The 4th U.S. Circuit Court of Appeals last week unanimously dismissed environmental groups' legal challenges against the Mountain Valley Pipeline, saying Congress has eliminated the court's jurisdiction over the cases.

Mountain Valley Pipeline had argued for the cases to be dismissed, citing the Fiscal Responsibility Act, which primarily suspended the nation's debt ceiling so the federal government wouldn't default on its obligations. The act also included language that said timely completion of the $6.6 billion, 42-inch-diameter natural gas pipeline from West Virginia into southern Virginia is in the national interest. The act ordered the approval of all remaining permits, removed judicial review of those permits and said only the D.C. Circuit Court of Appeals can hear challenges to the provision's constitutionality.

In writing the opinion, Judge James Wynn Jr. said Congress has the power to ratify federal agency approval, and while "Congress may not impermissibly tell this Court how to apply existing law," it is constitutional for Congress to provide a new legal standard and instruct the court to follow that standard.

More: *Cardinal News*

US Sees Record Number of Billion-dollar Disasters

So far this year, the U.S. has seen a record 15 weather disasters where costs and damages exceeded $1 billion, according to a report by the National Centers for Environmental Information.

It is the highest number of billion-dollar disasters to be reported during the period (January-July) since 1980. The cost of these events totaled more than $39.7 billion and resulted in 113 direct and indirect fatalities.

The number of disasters includes 13 severe storm events, one winter storm and one flooding event. It also includes tornado outbreaks, record-breaking flooding in California this past winter and a February winter storm that hammered the Northeast.

More: *The Hill*

Yellen Warns of Risks of Over-concentration of Supply Chains

U.S. Treasury Secretary **Janet Yellen** this week lauded the resilience of the nation's economy while also warning of the risks of over-concentrating clean energy supply chains.

"As we move away from fossil fuels, we remain concerned about the risks of over-concentration in clean energy supply chains," Yellen said at an event in Las Vegas. "Today, the production of critical clean energy inputs — from batteries to solar panels to critical minerals — is concentrated in a handful of countries."

Yellen's speech came days before the one-year anniversary of the Inflation Reduction Act.

More: *Reuters*

State Briefs

CALIFORNIA

New Rule Targets Nitrogen Oxides from Commercial Ovens

The South Coast Air Quality Management District last week voted 8-1 to approve a new rule that aims to dramatically reduce nitrogen oxide (NOx) emissions from hundreds of commercial food ovens in the district.

Starting in 2027, nearly 100 facilities operating a total of 218 ovens must meet a zero-emissions limit for NOx. To comply, virtually all the companies will have to replace their gas-burning ovens with electric options.

Electrifying California's 6,100 food and beverage facilities will eliminate a major source of gas demand in the state. In 2021, the sector accounted for more than 38% of the industrial gas demand served by SoCalGas, not including refineries, according to the latest California Gas Report.

More: *Canary Media*

ILLINOIS

Pritzker Vetoes Effort to Lift Nuclear Moratorium

Gov. **J.B. Pritzker** (D) last week vetoed legislation that would have lifted the state's ban on new nuclear construction.

The legislation, passed in May with bipartisan support, would have invalidated a 1987 law saying that new nuclear power facilities cannot be built in the state until a permanent waste storage option is available.

More: *Energy News Network*

Sangamon County to Ban CO2 Sequestration, Pipelines Through 2023

The Sangamon County Board last week voted to ban a carbon dioxide pipeline that would run through the county.

Heartland Greenway has proposed its Navigator Pipeline to transport CO_2 from ethanol and fertilizer plants from across the Midwest and inject it underground in Sangamon and Montgomery counties. However, board members said they have serious questions about what the pipeline means for roads, property value and safety.

The county has filed a Motion to Intervene with the commerce commission to have a voice in the approval process. The commission is expected to rule on the project in early 2024.

More: *WAND*

Task Force Considers Banning Solar Components, Batteries in Landfills

Legislation that was signed by Gov. J.B. Pritzker (D) on July 28 asks a task force to consider banning the dumping of solar components and batteries in landfills.

The new law follows a 2022 law that called for establishing a renewable energy recycling task force to study end-of-life options for a variety of clean energy technologies.

The life of a photovoltaic solar array is between 25 to 30 years. The National Renewable Energy Laboratory estimates that the U.S. will have to deal with about a million tons of solar panel waste by 2030, as utility-scale and smaller installations reach the end of their lives.

More: *Energy News Network*

LOUISIANA

First Solar to Build Manufacturing Plant in Iberia Parish

First Solar, the largest solar energy manufacturer in the Western Hemisphere, last week announced it has selected Acadiana Regional Airport in New Iberia as the site of its fifth American manufacturing facility that will produce photovoltaic solar modules.

The $1.1 billion facility will use 100% U.S.-made components in its solar panels.

To secure the project in Iberia Parish, the state offered First Solar various incentives including $30 million worth of performance-based grants.

More: *Louisiana Illuminator*

NEBRASKA

Greeley County Approves Wind Farm

The Greeley County Commission last week approved a special use permit for a wind farm southwest of Greeley.

The board approved a list of 42 conditions that must be met with the 41-turbine project from NextEra Energy Resources.

More: *The Grand Island Independent*

NEW MEXICO

Maxeon Solar to Build Manufacturing Plant in Albuquerque

Maxeon Solar Technologies, a Singapore-based company, announced last week that it will build a $1 billion manufacturing facility in Albuquerque.

The facility, which will be the company's first in the U.S., is projected to produce 8 million solar panels per year.

Construction is expected to begin in 2024.

More: *Albuquerque Journal*

OKLAHOMA

Grand River Dam Authority Looks to Replace Last Coal-fired Generator

The Grand River Dam Authority last week announced it is planning to purchase a $410 million natural-gas-fired combustion turbine and generator project to replace the last coal-fired generation unit at the Grand River Energy Center in Choteau.

The GRDA Board of Directors unanimously approved a $136 million contract with Mitsubishi Power America for the purchase of a 420-MW generating unit along with a $75 million, 12-year service agreement. The deal also includes options to upgrade the unit to allow for a hydrogen-natural gas fuel mix in the future. The new natural gas unit will replace the 492-MW coal-fired generator that came online in 1985.

The contracts are still pending final approval from the GRDA CEO and general counsel.

More: *The Frontier*

OHIO

PUC Approves New AES Security Plan, Raising Rates

The Public Utilities Commission last week unanimously approved a new "electric security plan" for AES Ohio, setting in place higher residential rates for the next three years.

The average net increase will be about $5.33 a month. A PUC spokesperson also noted that rates may rise further, as AES seeks to recover future costs related to capital investments in its distribution system.

More: *Dayton Daily News*

SOUTH DAKOTA

McCook County Fails to Pass Solar Moratorium

The McCook County Commission last week voted 3-2 against a temporary moratorium on issuing solar farm conditional use permits.

Chair Mark Dick said his primary reason for voting against a moratorium was that he wanted the county to retain control of input on the project and avoid ending up in court.

The decision leaves the door open for Grant Solar to re-apply for a permit for a 99-MW solar farm after being rejected in February.

More: *Mitchell Republic*

WISCONSIN

PUC Greenlights Alliant Energy Battery Projects

The Public Service Commission last week approved two Alliant Energy battery storage projects totaling 175 MW.

The approval allows construction of the 100-MW Grant County Battery Project and 75-MW Wood County Battery Project, which will be located alongside the company's Grant County and Wood County solar sites.

Alliant expects to begin construction on both projects in early 2024. The Wood County project is expected to be operational by the end of 2024, while the Grant County project is expected to be online by mid-2025.

More: *Alliant Energy*