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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: Wind farm near Palm Springs, Calif. CAISO and SPP are facing the most acute challenges from the increasing penetration of wind and solar generation. | *© RTO Insider LLC*

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

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Gas-electric Coordination, Resource Flexibility Cited in FERC Filings

By Amanda Durish Cook, Rich Heidorn Jr., Devin Leith-Yessian, Sam Mintz and Hudson Sangree

RTO stakeholders last week presented FERC with a cornucopia of suggestions for dealing with electrification and the increasing penetration of variable resources, some supportive of grid operators' actions, others calling them discriminatory.

Last April, FERC ordered CAISO, ISO-NE, MISO, NYISO, PJM and SPP to report on how system needs are changing with their shifting resource mixes and how they will meet them. (See *FERC Asks RTOs for Plans on Changing Market Needs*.)

On Thursday, 19 groups and companies filed comments responding to the RTOs' reports, which were filed in October (AD21-10).

Most of last week's responses supported FERC's position that it would not propose a "generic solution" across the RTOs/ISOs because of the diversity of the regions' generation mixes. But several commenters said the commission should provide guidance to RTO efforts to develop new products and market rules.

After four technical conferences in 2021 and dozens of comments, the commission has built a large record in the wide-ranging docket, which included discussions of resource adequacy, interregional planning, NERC reliability standards and distributed energy resources.

The first technical conference in the docket in March 2021 focused on capacity markets in PJM, ISO-NE and NYISO. (See *PJM MOPR in the Crosshairs at FERC Tech Conference*.) A second conference focused on ISO-NE's markets. (See *Regulators, ISO-NE Discuss Market Changes at FERC Tech Conference*.) In September and October 2021, the commission held conferences on energy and ancillary services (E&AS) markets, with a focus on the need for flexible ramping products to supplement wind and solar

Wind farm near Palm Springs, Calif. CAISO and SPP are facing the most acute challenges from the increasing penetration of wind and solar generation. | © *RTO Insider LLC*

Renewables, Electrification Increase Uncertainty for RTOs

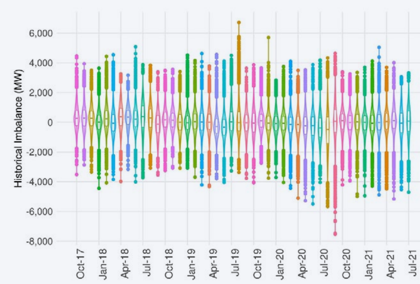
By Amanda Durish Cook, Rich Heidorn Jr., Devin Leith-Yessian, Sam Mintz and Hudson Sangree

In October, CAISO, ISO-NE, MISO, NYISO, PJM and SPP filed reports with FERC on how their system needs are changing in response to decarbonization and their shifting resource mixes (AD21-10). Last week, 19 groups and companies filed comments responding to the RTO/ISO reports.

Below is a summary of how the grid operators say they are working to ensure reliability and what the commenters think of their plans.

CAISO

CAISO *told FERC* its system needs are changing in response to the state's 100% clean energy by 2045 mandate under Senate Bill 100.



CAISO monthly trend of historical day-ahead imbalances, which can exceed 6,000 MW, requiring large amounts of reserved capacity. | *CAISO*

"CAISO is actively engaged in addressing the evolving resource mix, an evolving market, and a growing recognition that regional coordination is necessary to enhance efficiency and reliability," it said, adding that "weather patterns affected by climate change have created extreme conditions beyond those anticipated by current planning standards."

Continued on page 7

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generation. (See *Flexible Ramping Grows as Ancillary Service* and *Stakeholders Ask FERC to Support E&AS Market Changes*.)

The only commission actions to come out of the fact-finding thus far have been orders to essentially eliminate the minimum offer price rule in PJM and ISO-NE. Those votes came with a 3-2 Democrat-controlled commission. With the Jan. 3 departure of Chair Richard Glick, Acting Chair Willie Phillips and Democrat Allison Clements will be unable to approve any rule changes without winning over Republican James Danly or — more likely — Mark Christie.

Deference vs. Standardization

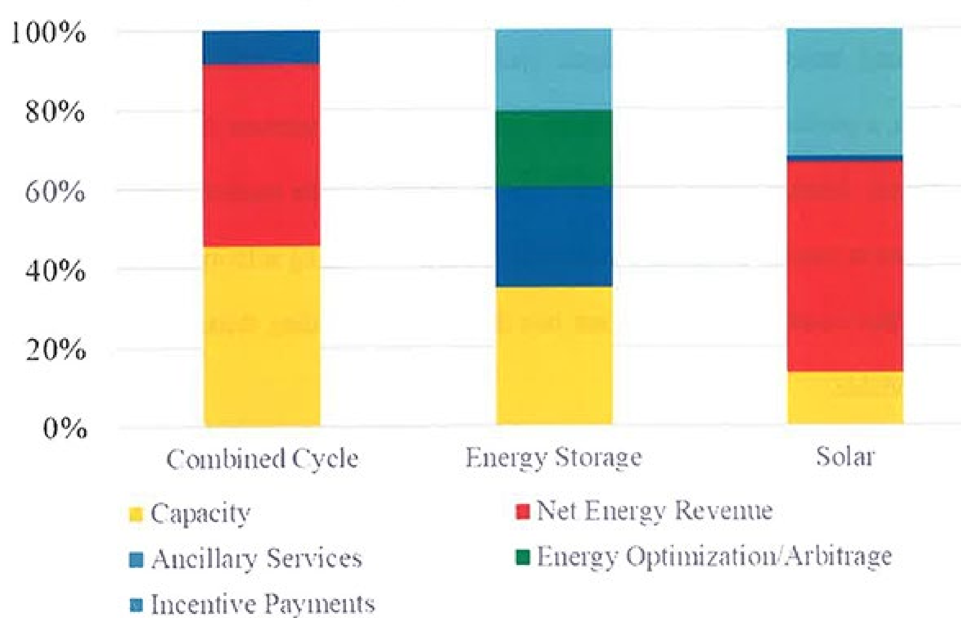
The Edison Electric Institute said FERC should defer to the RTOs. "It is critical that RTOs and ISOs be allowed to identify issues and propose solutions to changing system needs through their stakeholder processes," EEI said. "It is especially important that the commission allow the existing reform efforts described in the RTO/ISO reports to play out." EEI also urged the commission not to consider action on interregional transfer capability in the docket, saying docket AD23-3, the subject of a FERC workshop in December, was a more "appropriate" venue. (See *FERC Considers Interregional Transfer Requirements*.)

In contrast, the American Clean Power Association, American Council on Renewable Energy and the Solar Energy Industries Association — filing jointly as "Clean Energy Associations" — called for standardization across RTOs. "Competition in the markets will be improved if the RTOs/ISOs adopt common terms, products, protocols, and review measures," they said.

Constellation Energy (NASDAQ: CEG) said ISO-NE could use FERC guidance in designing operating reserves and related products, citing the RTO's statement that it is difficult for RTOs and their stakeholders "to make progress … in the absence of proactive guidance from the commission."

Shell (NYSE:SHEL) — which owns Shell New Energies U.S., developers of the Atlantic Shores and Mayflower Wind offshore wind projects, and Savion, a utility-scale solar and energy storage developer — said FERC "must provide an overall framework to both ground and discipline RTO/ISO efforts to ensure reliability is maintained" in light of state actions to address climate change.

"Addressing one-off questions on a stand-alone basis — such as whether locational-based marginal pricing for energy markets can continue; whether co-optimized ancillary service markets with opportunity cost pricing will deliver the right resources; or even whether capacity markets serve as the right platform for providing the 'missing money' needed to meet resource adequacy challenges — will be woefully insufficient," it said. "Issuing a policy statement that defines general principles without prescribing set solutions will provide cohesion but permit the necessary flexibility for each RTO/ISO to efficiently and effectively meet its respective regional needs."



Revenue stack comparison: Most of solar resources' revenues comes from environmental attribute markets and energy markets. | *Shell*

Advanced Energy United, formerly Advanced Energy Economy, said FERC should "engage critically" on the issue of capacity accreditation and "proactively engage on flexibility" through new energy and ancillary service products and evaluation of existing market rules.

The group also called for the commission to finalize its rulemakings on transmission planning, cost allocation and generator interconnection; complete rulings in Order No. 2222 dockets on removing barriers to DERs and look for ways to increase the roles of DERs and flexible demand; and improve wholesale-retail coordination.

Generation Dispatch

Constellation said RTOs should be more transparent about their out-of-market actions.

"There is little understanding — by the market participants who are most affected — of RTO out-of-market actions such as manual unit commitments, posturing and load biasing; the frequency or magnitude of these activities; the circumstances that necessitate them; or, importantly, how these 'practice[s] … affect … rates,'" it said. "Most of these out-of-market actions are taken in control rooms and are hidden from market participants."

The Clean Energy Associations called for increased use of probabilistic unit commitment, saying it would produce more efficient, lower-risk operations. "For example, if forecasts indicate a significant chance of both very high load and very low renewable output, operators will likely want to commit more resources. However, because those risks are not reflected in the median value for either forecast, current deterministic methods do not automatically incorporate them into commitment decisions, forcing operators to attempt to subjectively incorporate them."

Capacity Markets, Ancillary Services

R Street Institute called for less reliance on capacity markets and more demand-side participation, which it said is "chronically underutilized."

"The most efficient and accurate price signals come from energy and ancillary service markets, where the reflection of actual conditions occur on a granular basis, unlike the more administrative constraints at broader estimation of transmission constraints in capacity markets," it said.

Environmental groups, including Earthjustice, Natural Resources Defense Council,

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Sierra Club, Sustainable FERC Project and the Environmental Defense Fund, also called for more demand-side solutions. "Resources such as demand response, electric storage and distributed energy resources can go a long way to ameliorate the resource adequacy shortfalls that some of the RTOs/ISOs complain of in their reports."

The Clean Energy Associations cited PJM in calling for "reducing over-procurement of capacity," and urged the commission hold a dedicated technical conference on capacity accreditation.

They also said energy market price caps should be increased to reflect the true value of lost load. "CAISO, MISO and PJM all have relatively low price caps in their energy markets, which can mute the incentive for performance during periods of extreme scarcity and result in under-investment in flexible generation that contributes to resource adequacy," they said. "Low price caps can also cause unintended consequences in energy markets. For example, energy market price caps in CAISO caused many storage resources to prematurely discharge during early afternoon periods in the September 2022 heat wave because once prices hit the $2000/MWh cap, storage resources had no incentive to retain their state of charge even though it was known that net load would be even higher later in the afternoon and evening."

They said FERC should also consider making planned generator and transmission outages transparent "so they are priced in the market."

RTOs could also play a greater role in coordinating transmission and generation outages to reduce congestion costs, they said. MISO's Independent Market Monitor has recommended such a change, noting that: "ISO-New England does have the authority to examine economic costs in evaluating and approving transmission outages, which has been found to have been very effective at avoiding unnecessary congestion costs."

Broaden the Inquiry?

The Electricity Consumers Resource Council (ELCON), which represents large industrial energy users, was among commenters that called for FERC to broaden its inquiry.

"This proceeding is a perfect opportunity to explore whether — and if so, how — the policy goals outlined by the Commission 23 years ago in Order No. 2000 have been achieved," ELCON said. "At this point, the track record with existing institutions is nothing if not sufficiently long. FERC has employees on staff who were born, raised and earned graduate degrees in the time since Order No. 2000 was issued."

The Clean Energy Buyers Association, which represents 89 Fortune 500 companies, said it agreed with Commissioner Christie that the commission should expand the scope of its inquiry beyond E&AS markets, "including requiring RTOs/ISOs to address whether intermittent and hybrid resources are compensated appropriately to ensure reliability."

Advanced Energy United said the commission should require the RTOs to update their reports on modernizing electricity market design annually. "Having year-over-year data and insights from the RTOs/ISOs will give the commission insight into emerging grid and market changes and a deeper understanding of long-term trends."

R Street Institute challenged the presumption that RTOs will continue in their existing form, reiterating its *request*, with ELCON and others, for a congressional study of the electric power industry and its regulation. "The benefits of wholesale competition have not always been clear for retail consumers, sometimes because of unmitigated market power but more often because of faulty retail regulation," R Street said.

Gas-electric Coordination

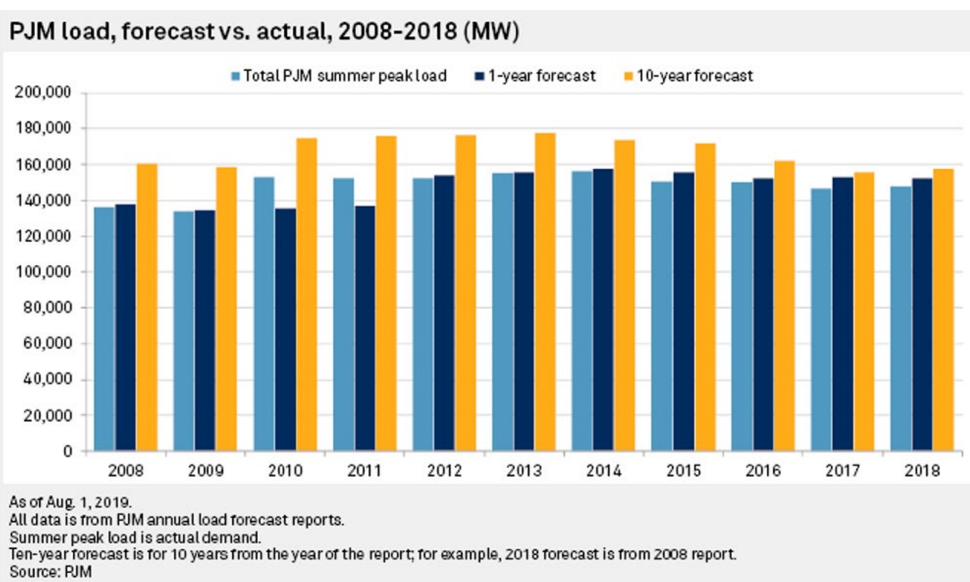
The Electric Power Supply Association asked FERC to redouble efforts to improve gas-electric coordination, warning "we are approaching a precipice in terms of system reliability which must be acknowledged.

"The need to reform power markets to address planning parameters, operational issues and flexibility needs is no longer a theoretical exercise but an imminent concern that must be addressed. Additionally, the lessons of Winter Storms Uri in 2021 and Elliott just a few weeks ago shine a bright and unavoidable light on ongoing coordination problems between the electricity and natural gas systems, which are likely to intensify as the system becomes increasingly dependent on dispatchable resources including natural gas-fired generation," EPSA said.

Electric-gas coordination has been an issue in PJM since at least the 2014 polar vortex, when the RTO saw more than 20% of its gas-fired generation unavailable. The high outage rate was supposed to be solved by PJM's Capacity Performance rules, yet the RTO saw similar rates of natural gas plant outages over the Christmas holiday. (See *PJM Gas Generator Failures Eyed in Elliott Storm Review*.)

"The issues raised by the challenges of gas-electric coordination are complex and implicate long-held practices in both industries, contributing to the reluctance to change or reform from either side. There are reforms that can be undertaken in electricity markets to address natural gas supply issues and availability. Notably, however, those power market reforms likely need to be matched in some manner by either reforms or adjustments on the natural gas side."

EPSA said the discussions should go beyond weather to also ensure sufficient gas-fired



Groups filing as the "Clean Energy Associations" complained PJM's capacity market has resulted in over-procurement due to overestimates of load growth, unduly conservative assumptions about imports during peak demand periods and an assumed net cost of new entry that is too high. | *PJM*

FERC/Federal News

capacity to respond to ramping needs. "The broader discussion must evaluate the need for additional supply and transportation capacity to ensure units can run when called and not be restricted by a system that is not expanding with the increase in demand," it said.

EPSA said solutions could require "reimbursement for the cost of fuel in a manner not provided for today."

EEI suggested the commission convene a technical conference to discuss the issue.

Barriers to Entry

Environmental groups including Earthjustice, Natural Resources Defense Council, Sierra Club, Sustainable FERC Project and the Environmental Defense Fund said the RTO/ISO reports "fail to address barriers to entry that resources face in attempting to gain access to markets."

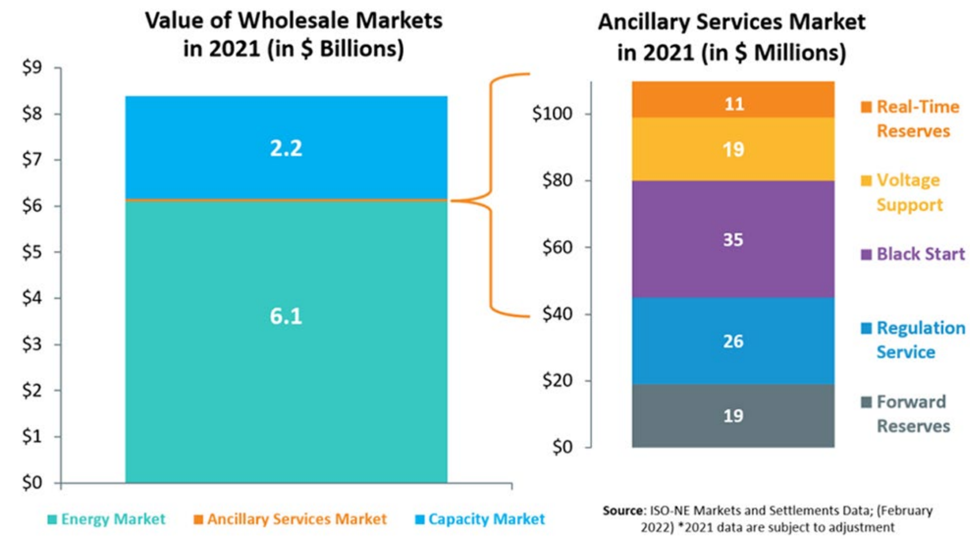
"The commission should require that each RTO/ISO focus on improving existing ancillary services prior to identifying new services or expanding the scope of market," they said. Among the improvements the groups would like: shortening the durational requirements for eligibility to provide ancillary services and identifying stacking techniques for battery storage and hybrid resources. They also called for development of new ancillary services such as market-based fast frequency response and primary frequency response products and for splitting regulation services into upward and downward ramping products.

They said FERC should open proceedings under Section 206 of the Federal Power Act over MISO's refusal to let dispatchable intermittent resources (DIRs), such as wind and solar, sell ancillary grid services in the operating reserves markets. They said MISO's report "understates the ancillary services contributions of inverter-based resources while overstating the contributions of legacy resources."

"It is well-accepted that DIRs and hybrid resources are technically capable of providing these services, and often more quickly and accurately than traditional thermal resources. However, MISO's blanket prohibition is locking these resources out of the market, unnecessarily removing tools at MISO's disposal to lower ancillary services costs while simultaneously increasing reliability," they said. (See *MISO Plans to Bar Intermittent Resources from Ramp Capability*.)

The Clean Energy Associations said RTOs/ISOs should not interfere with market participants' use of their commitment and dispatch preferences, including giving battery storage operators the option of managing their state-of-charge at all times.

"Today wind and solar may or may not be the most cost-effective resources to provide certain services given the opportunity cost of curtailing renewable generation," they acknowledged. "However, as the renewable penetration increases, curtailment will increase, and the opportunity cost of foregone energy production will decline so that renewables may increasingly become cost-effective sources of ancillary services and flexibility in the upward as well as downward direction."

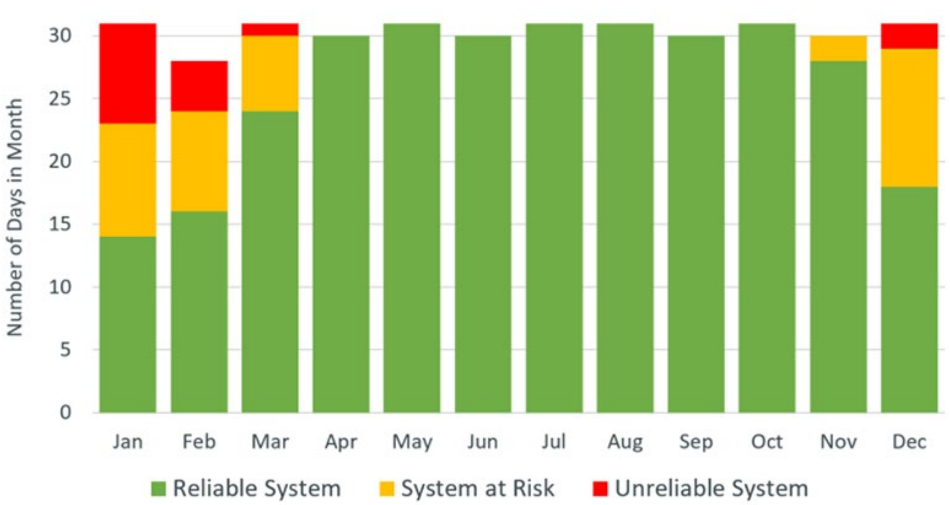


ISO-NE's markets for ancillary services represent only $110 million in 2021, compared to $8.4 billion of overall wholesale electricity market costs that year. | *ISO-NE*

Saving Coal

Coal industry group America's Power asked the commission to require RTOs pay coal generators to keep operating to reflect the reliability benefit of their dispatchability and on-site fuel storage. "We respectfully urge the commission to require RTOs to value the needed attributes to mitigate the impacts of further retirements until global reforms can be developed and implemented," it said.

Tom Stacy and George Taylor, who have consulted with America's Power, filed comments calling themselves "Independent Ratepayer Advocates," in which they said variable energy resources should not be granted interconnection rights unless their sites also include a dispatchable resource or storage. "The commission should resist the desire of VER investors — or anyone else — to continue to expand their market share while avoiding costs their resources create," they said. ■



Days per month of natural gas supply risk under deep decarbonization in New England. | *ISO-NE*

FERC/Federal News

Renewables, Electrification Increase Uncertainty for RTOs

Continued from page 3

One way CAISO is addressing its needs is with large amounts of battery storage to provide power during hot summer evenings after solar goes offline but air conditioning demand remains high. The ISO ordered rolling blackouts in August 2020, and had near misses in the summers of 2021 and 2022, under such conditions.

"The addition of lithium-ion storage capacity has been an extremely positive development," CAISO said. As of October 2022, the ISO had about 4,300 MW of storage capacity available for dispatch; the California Public Utilities Commission, which is in charge of ordering procurement by the state's three large investor-owned utilities, has called for 10,000 MW of additional storage by 2024.

Another way CAISO plans to deal with changes in the resource mix and load variability is through its proposed extended day-ahead market (EDAM) for its real-time Western Energy Imbalance Market.

"The EDAM will build upon the proven ability of the WEIM to increase regional coordination, support states' policy goals and meet demand cost-effectively by supporting the rapidly evolving Western resource adequacy landscape," CAISO said.

Managing its "unprecedented transition requires us to look very carefully at both the short and the long term," CAISO said: "short term because we must maintain reliability during the transition to a carbon-free grid, and long term because we must make sound decisions now to help us reach that destination in the most reliable and cost-effective way."

In February 2022, CAISO published its first 20-Year Transmission Outlook, "a long-term conceptual plan" of the transmission grid based on input from the CPUC and the California Energy Commission.

Its new 5-Year Strategic Plan focuses on what the organization must do in the short term to strengthen reliability during the transition.

To ensure resource adequacy, CAISO said it would rely on the Western Power Pool's Western Resource Adequacy Program and California's efforts to evolve its resource adequacy program through advanced computer modeling. "Together with its partners, the CAISO is actively working to develop a multiple-year roadmap that relies on its markets to provide reliable system operations in light of the changing nature of resources and load patterns throughout the West," it said.

Wind farm near Palm Springs, Calif. | © RTO Insider LLC

In comments filed last week, the American Petroleum Institute cited CAISO's experience during strained conditions as a reason natural gas generators' fast-ramping capability are needed. California continues to rely heavily on gas generation, especially at times when solar is unavailable.

"CAISO, which has the highest share of solar generation of the six ISO/RTOs, has already observed an increase in uncertainty around its net load forecasts," API said.

"As the share of non-dispatchable resources grows, it can become difficult to guarantee that generation will be available when needed — particularly when resources with flexible attributes are either forced into retirement or not developed in the first place due to market, regulatory or legislative headwinds," it said. "California faced such an issue in August 2020, when insufficient fast-ramping resources were available to compensate for the evening decline in solar generation and CAISO was forced to shed load on consecutive days. As former FERC Commissioner Tony Clark concluded in a recent opinion piece, 'On-demand resources may not run as often in a renewables-heavy future, but the value of their ability to run when called upon will be critical.'"

Advanced Energy United (formerly Advanced Energy Economy) offered its thoughts last week on several parts of CAISO's submission.

"CAISO predicts that 'artificial intelligence and machine learning will play an increasingly important role as the energy industry continues its trend towards more complex and distributed systems,'" the group said. "Given the foundational role of software in supporting critical RTO/ISO functions, the commission should work to track RTO/ISO software needs and upgrades and look for ways to support expedited software upgrades and use of new and emerging tools and practices."

Advanced Energy endorsed CAISO's recommendation that the commission "continue to facilitate industry dialogue regarding the coordination between the transmission and distribution interface."

"This is especially critical in light of the trend mentioned by multiple RTOs/ISOs toward increased electrification of transportation and heating; ensuring that these end uses can be leveraged as a grid resource rather than simply adding a new source of load for grid operators to balance will be essential to maintain affordability and reliability in light of shifting system needs."

FERC/Federal News

ISO-NE

ISO-NE *said* it recognizes its energy systems are in the "early stages of a significant shift" caused by electrification and decarbonization goals in the six states of New England.

Among the changes that ISO-NE is preparing for are increasing winter peaks in the next five years, and the potential for a full-blown shift to a winter-peaking system in the next 10.

The grid operator said it expects to need "additional resource physical capabilities, ISO informational capabilities and markets' capabilities to incent the former," over those time frames.

ISO-NE cited what CEO Gordon van Welie has called the "four pillars" of New England's energy future: clean energy, balancing resources, energy adequacy and transmission investment. It stopped short of making any specific asks of FERC, but called on the commission to remain flexible in its approach to overseeing RTOs.

"We look forward to continued efforts by the commission to remain responsive to the evolving resource mix and load profiles of individual RTO/ISO regions, and any related future market reforms that the evolving energy system may motivate," the RTO said.

Four public power systems from Massachusetts, Connecticut, New Hampshire and Vermont called on FERC and ISO-NE to continue to focus on reliability, saying, "New England today is facing profound winter reliability issues that require swift action."

Specifically, the groups wrote that FERC should mandate the use of competitive processes in transmission development, take a closer look at New England's rules for fuel procurement and consider creating a regional energy reserve. They also urged a major revamp of ISO-NE's capacity market, calling for a seasonal auction to replace the existing annual one.

≥80% by 2050	Five states mandate greenhouse gas reductions economy wide: MA, CT, ME, RI, and VT (mostly below 1990 levels)
Net-Zero by 2050 80% by 2050	MA emissions requirement MA clean energy standard
90% by 2050	VT renewable energy requirement
100% by 2050 Carbon-Neutral by 2045	ME renewable energy goal ME emissions requirement
100% by 2040	CT zero-carbon electricity requirement
100% by 2030	RI renewable energy requirement

New England's emission reduction goals | *ISO-NE*

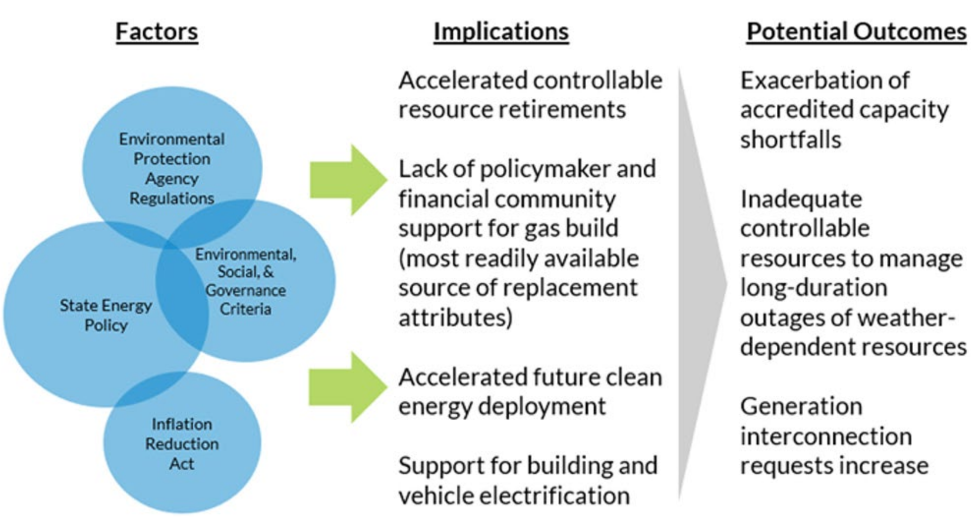
They also said ISO-NE should look at new market products to incentivize building balancing resources and commit to undertaking cost-benefit analyses as it evaluates changes to market rules.

MISO

MISO *said* adapting its markets to reliably meet future system needs has been "core to MISO's mission and vision" since it introduced its energy market in 2005.

The grid operator cited its plan to use a seasonal accreditation of capacity, the opening of its markets to electric storage and the 2021 rollout of its short-term reserve product. It also said its long-range transmission portfolios and its ongoing market platform replacement are meant to keep the system nimble.

MISO also cited analyses such as its "Markets of the Future" report and annual regional resource assessment as ways to keep close tabs on its evolving resource mix and anticipate what new market products might be needed.



Policy drivers are accelerating the fleet transition and associated risks, MISO says. | *MISO*

The RTO said it considers market pricing "a powerful signal" to attracting resources. In its "ideal state," it said, it would remove the requirement that it must declare an emergency to access its load-modifying and other "emergency only" resources and be able to commit and dispatch them "through more regular market operations."

MISO has begun discussions with stakeholders on how to appropriately value and maintain resources that supply beneficial system attributes. It has defined six system reliability attributes as necessary, including resource availability, the ability to deliver long-duration energy at a high output, rapid start-up times, providing voltage stability, ramp-up capability and fuel certainty. (See *MISO Considers Resource Attributes as Thermal Output Falls*.)

NYISO

NYISO *said* it is simultaneously responding to more frequent extreme weather and higher temperatures caused by climate change and the renewable requirements of the Climate Leadership and Community Protection Act (CLCPA). Reaching the CLCPA's targets — 70% renewable electricity by 2030; 100% emissions-free electricity by 2040 — "will require unprecedented levels of investment in both new supply and transmission resources."

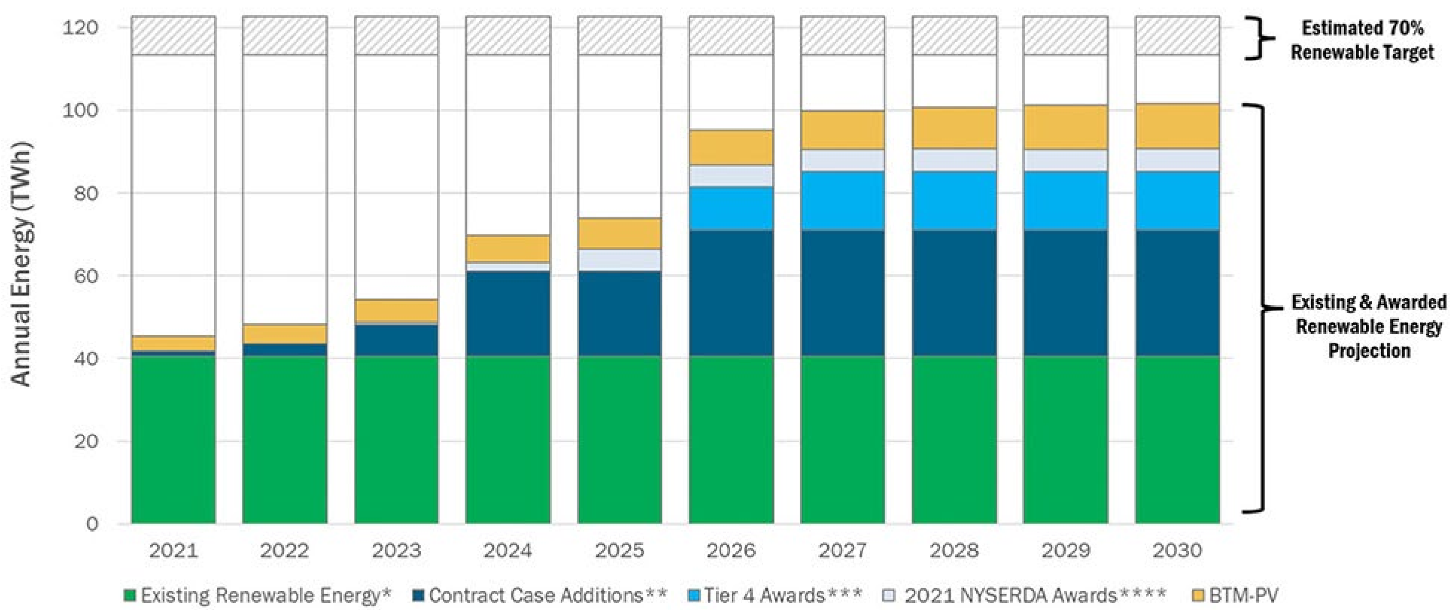
The ISO's 2020 Climate Change Impact and Resilience Study said it could be facing one-hour ramp requirements of more than 10,000 MW and a six-hour ramp of more than 25,000 MW by winter 2040. In 2021, in contrast, the ISO's maximum one-hour ramp was 1,800 MW, and the largest ramp was 8,800 MW.

NYISO said it faces uncertainties including "weather, net load forecasts, actual available energy from intermittent wind and solar resources, available energy from limited-energy resources, reduced availability of traditional flexible generation resources and higher probabilities that weather, or other factors, lead to correlated supply and transmission issues." In July 2019, it experienced a 36-hour period when the state's wind resources produced only 4% of their maximum output.

The ISO identified six time frames in which it must balance the variance in intermittent resources, ranging from six seconds (for regulation service) to decades — the time horizon over which investments in resources able to provide balancing will be made.

NYISO told FERC its energy and ancillary services markets are "working efficiently," citing its operating reserve demand curves, which were changed in 2021, and stakeholders'

FERC/Federal News



Progress toward New York's "70 x 30" mandate | *NYISO*

recent approval of its constraint-specific transmission shortage pricing project. The latter project is intended to help its market software redispatch suppliers to alleviate transmission constraints and identify locations where new resources could provide the greatest benefits.

"The upcoming balancing intermittency project and the initiative to review real-time market features to enhance incentives to follow NYISO instructions directly respond to expected ramping and flexibility needs," it said. The real-time project will consider lengthening the look-ahead capabilities of the ISO's real-time commitment and real-time dispatch software.

It acknowledged that the low marginal costs of renewables will require changes to the markets to balance intermittency and improve price formation.

"Determining the quantity and location of operating reserves more dynamically will be instrumental in preparing the markets for the new grid risks as the resource mix evolves."

Simultaneously co-optimizing energy and ancillary services requirements will increase revenues in those markets, the ISO said. "Absent ancillary services market changes or other wholesale energy market changes to improve incentives for flexible resource availability, market signals to retain and invest in flexible, controllable resources may not be sufficient."

Another source of uncertainty is behind-the-meter solar PV. The ISO forecasts that 6,000 MW of BTM solar nameplate capacity will be installed by 2024, rising to 10,000 MW by 2030.

The ISO and its stakeholders are considering additional changes, including the implementation of reserve requirements within constrained load pockets; additional availability incentives for suppliers on Long Island; five-minute transaction scheduling; and separating up and down regulation service.

In response to Commissioner Mark Christie's question on whether LMPs remain the best way to run energy and capacity markets, the ISO attached to its filing a report by economists Scott Harvey, of FTI Consulting, and William Hogan, of the Harvard Kennedy School.

Harvey and Hogan rejected those who question whether LMPs still make sense in a world of low-marginal-cost variable resources. "The critical role for LMP was true in the past, is true today, and will be true and more important with the anticipated changing resources mix," they wrote.

PJM

PJM aims to meet the challenges presented by growing renewable penetration and electrification by expanding its energy and ancillary services market to include pricing of flexibility attributes. In its report to the commission, the RTO said many of the characteristics of dispatchable generation will be crucial through the clean energy transition — such as the ability to ramp, cycling capability, quick start times and low minimum run times.

"A significant challenge PJM faces over the next five to 10 years is the disorderly retirement of resources that provide needed ancillary services," the RTO *said*. "The limitations in how these resources are priced today could well add to the premature and disorderly retirement of these needed resources that are not priced accurately in today's markets."

While the RTO believes it has adequate flexibility in the near term, it said it must create defined values for attributes as quickly as possible to incentivize generation owners to keep their facilities online.

"The value in addressing this issue now is that prices for this additional flexibility will rise slowly as the fleet transitions and send early price signals on the increasing value of flexibility. This is critical to avoiding the disorderly retirement of resources," PJM wrote.

The RTO urged the commission not to take a "passive stance."

"A policy statement outlining the commission's expectations would help to focus RTOs and their stakeholders on these issues at a time when there are countless issues that could distract from their development," it said. "Moreover, such a policy statement, if adopted on a bipartisan basis, could ensure a level of continuity in the commission's direction that would further incent the industry to move proactively."

PJM's Independent Market Monitor argued that the RTO's core market design elements

FERC/Federal News

already provide the flexibility it will need going into the future. It said the focus should be on removing existing barriers rather than creating new market products.

"Creating new ancillary services products and repeatedly revising the existing ones is a distraction from identifying opportunities to improve dispatch tools and enhancing basic market rules to unlock existing resource flexibility," the Monitor wrote in response to PJM's filing.

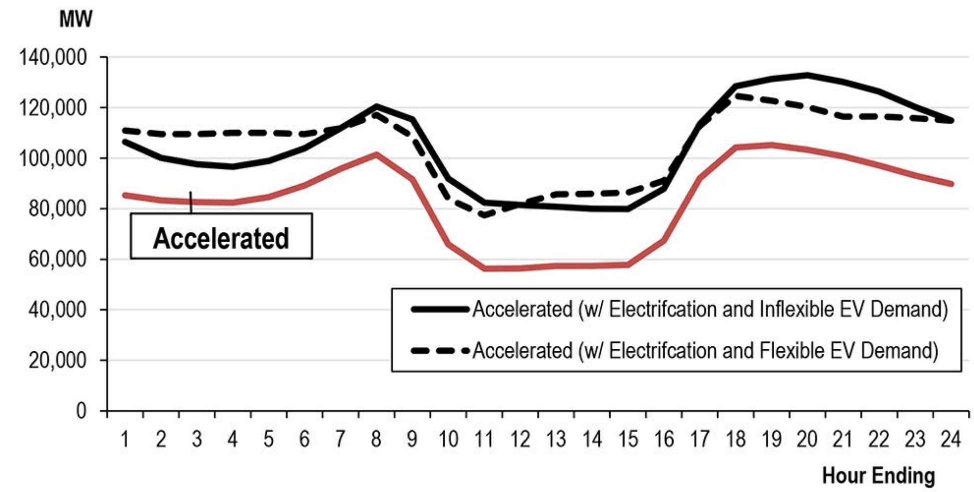
Current market rules often allow resources to avoid defining their flexible operating parameters outside of instances where they fail the market power test, or during weather alerts and emergencies, the Monitor said. For example, combined cycle units have the physical capability to be dispatched on and off for morning and afternoon peaks, and typically do not offer their start and down time parameters on their price schedules.

The IMM also said "inferior capacity resources" that are exempted from must-offer rules — namely intermittent generation, storage and demand response — are undermining the reliability offered by PJM's capacity market.

The PJM Industrial Customer Coalition said that the RTO must ensure that load is not responsible for resources that cannot meet their obligations.

"Currently, load is fully responsible for the payments associated with the reserve products in PJM. If certain resources are not able to meet their reserve obligations due to the intermittency of those resources or for other reasons, those resources should bear an appropriate cost; the full risk and costs should not be borne directly by consumers," the coalition wrote.

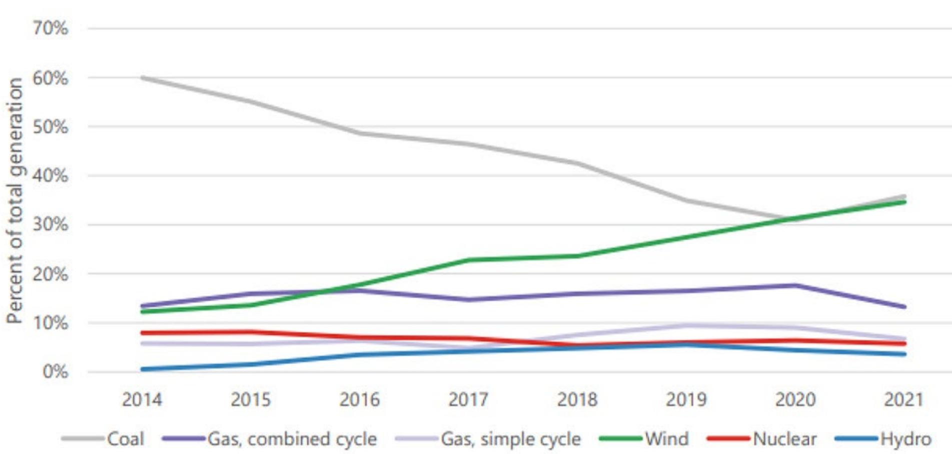
The ICC also argued that all generation types carry some physical flexibility and that they should be required to offer that capability to grid operators. Those resources that cannot provide a range for its flexibility or fail to follow dispatch instructions should be obligated to purchase flexibility from other resources or their respective RTO, it said.



Winter load shape with electrification | *PJM*

"Resources that cannot provide desired flexibility and dispatchability attributes should appear more costly and less desirable than resources that can provide the desired attributes. As a result, the mantra of 'reliability through markets' would continue to be fostered through proper investment signals," it wrote.

The PJM Power Providers Group (P3) noted that the RTO is forecasting strong load growth as thermal resources are scheduled to retire. It argued that the renewable resources expected to go online are not a "megawatt-for-megawatt" replacement for those going offline, particularly as risk moves to the evening hours.



Share of SPP's real-time, annual generation by technology type | *SPP*

To address the reliability challenges expected in the future, P3 said that an overhaul of the capacity market is necessary to undo "myopic regulatory decisions from the commission, illogical proposals from the RTO" and delays in running auctions. P3 said the current market is unsustainable, with resources exposed to non-performance charges during extreme weather, no ability to independently evaluate risk and no protection from buyer market power.

SPP

SPP's *report* documented the RTO's response to the rapid growth in wind energy and its increasing peak demand.

The RTO's 33 GW of installed and registered wind power capacity represents 29% of its total capacity and 38% of its total energy. It also has seen a continued drop in coal generation, although rising natural gas prices allowed its usage to rebound in 2021.

Because of rising high temperatures, the RTO said, its coincident instantaneous peak demand has risen more than 7% in two years, from 49,569 MW in 2020 to 53,243 MW in July 2022.

It also reported increasing uncertainty in load forecasting because of demand response and behind-the-meter generation. "SPP receives load forecasts from its members that inform SPP's own load forecasts, and these load forecasts may be performed differently," it said.

It has also seen increased generation variability, which it manages through reliability unit commitment studies and manual operator commitments and its new ramp capability product.

"SPP's primary source of uncertainty comes

FERC/Federal News

from generation, not from load," it said. "With the balance between available flexibility and system variability expected to tighten in the future, efficient methods to assist in providing the needed flexibility with the available generation fleet will become increasingly important to economical and reliable operations."

The RTO said its requirement is for resources that are "visible, forecastable and responsively dispatchable."

It recently revised its balancing authority emergency operating plan to incorporate information on generators' on-site fuel and the ability of the BA to allow resources to take actions to conserve fuel. The RTO is also tracking plant retirements based on owners' plans instead of making assumptions based on plants' age.

SPP said it will need more information from its 550 distribution utilities as additional resources interconnect on distribution lines.

Another concern is the increasing complexity of the system, which is making it more difficult for software to clear, solve and post the results of SPP's market in a timely fashion.

"The SPP market clearing engine has to optimize an extensive mathematical model (greater than 1,000 resources, large amounts of transmission constraints over a large footprint, granular modeling)," it said. "The potential addition of thousands of distributed energy resources, storage, greenhouse gas logic and continued variable energy resource growth could require adjustments to how SPP clears the market."

SPP said it has an increased need for visibility of resources. "This means knowing where resources are on the system and forecasting their output. Visibility concerns arise with increasing numbers of distributed energy resources and behind-the-meter generation. This generation may not be registered in SPP's markets and may be accounted for differently in the load forecasts of distribution utilities connected to the transmission system operated by SPP," it said.

"Another potential problem with resource visibility is the potential for mobile storage resources (both plug-in vehicle and commercial-size truck bed storage) within SPP's footprint. This possibility may be more likely as new electric charging stations along interstate highways come online."

"Renewables have not caused any new problems but have only highlighted the shortcoming of the market," SPP's Market Monitoring Unit said in its comments last week.

The MMU said the RTO needs to construct its rules with an eye to "flexibility, dependability, availability, resiliency and quality."

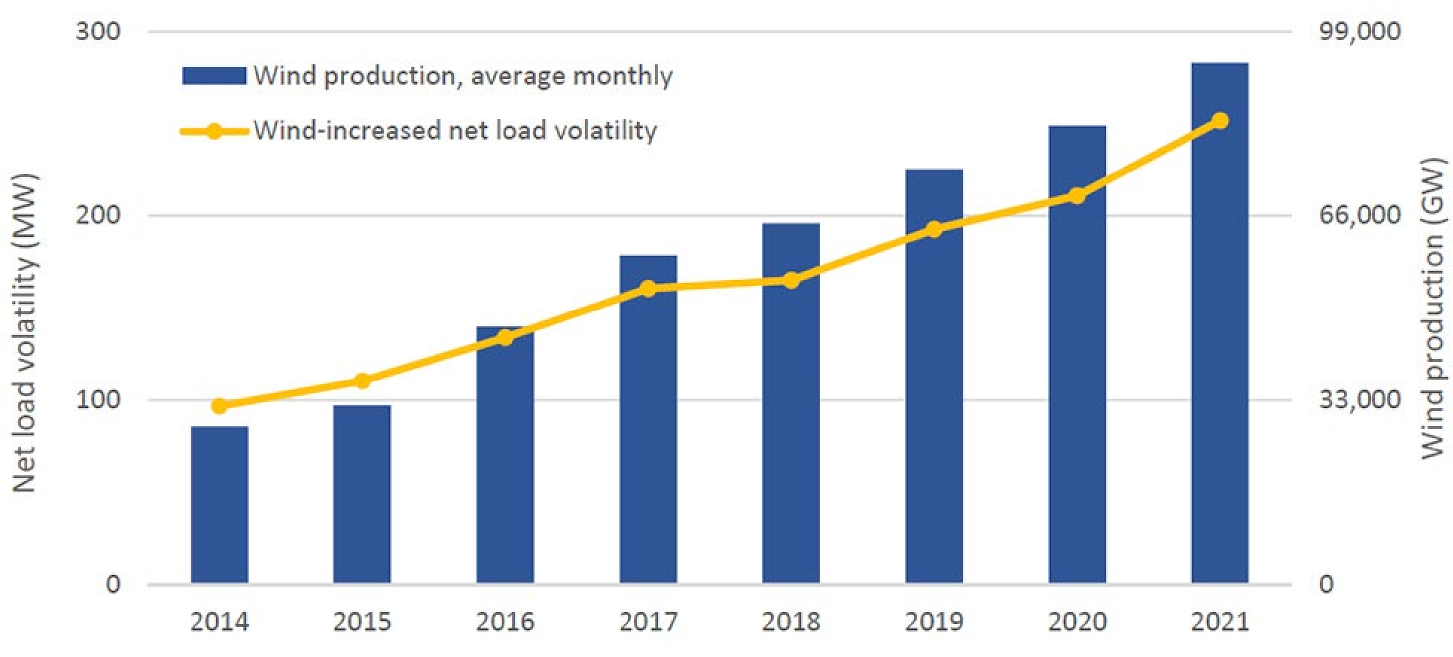
"These attributes must be defined and incentivized, or they may not be provided in the future," the MMU said.

The MMU noted that wind's market share has nearly tripled from 2014 to 2021 to about 35% of total annual generation. Compounding the challenges, in about half of all real-time intervals, wind production moves in the opposite direction of load, it said.

"Although almost all weather-dependent renewables are dispatchable in the down direction, they were expected to follow dispatch instructions in less than 7% of resource intervals, compared to about 80% for non-renewables.

"When not following a dispatch instruction, weather-dependent renewable output varies irrespective of price, causing a need for rampable capacity separate from load."

Almost 36% of capacity in SPP is more than 40 years old, most of it gas and coal. ■



Net load volatility increases with wind production | *SPP*

Phillips Says Transmission NOPRs Still a Priority

Acting Chairman Makes 1st Public Comments Since Promotion

By James Downing and K Kaufmann

WASHINGTON — Acting FERC Chairman Willie Phillips on Wednesday said he would continue to prioritize the transmission initiatives his predecessor started in his first public comments since being named to run the agency at the beginning of the year.

Transmission is important to ensuring reliability and resilience, Phillips said, and they have been areas he has focused on since joining FERC in 2021. The Inflation Reduction Act should accelerate the transition towards clean energy that the industry is going through, which will also need ample new transmission.

"I'm glad to say that the transmission NOPRs [Notices of Proposed Rulemakings] and proceedings that we started last year, they're aimed at doing just that," Phillips said at Energy Bar Association Northeast Chapter's Winter Summit. "As your chairman, I want to make sure that we keep the momentum going on these important transmission reform efforts."

Phillips also made similar comments before the D.C. Public Service Commission's Clean Energy Summit the same day.

"We're not going to sit on our hands," Phillips said at the PSC, where he was chair before he joined FERC. "I've already started to engage my colleagues, to engage them and talk about, what are the ways we can continue to move forward? I think that's the only way to reach the administration's goal of clean energy by 2035."

While some have argued that building out the infrastructure needed to combat climate change is at odds with environmental justice, Phillips said, he is not one of them.

"I think with the opportunities with advanced reconductoring, in particular, where you don't just have to build, but you can have these lines that are able to reduce the amount of energy loss and increase the amount of energy that can flow across for many, many miles, I think that there's so many opportunities to save money," he added.

Advanced transmission technology can reduce the need for new transmission; that not only addresses more traditional environmental justice concerns but ensures the transition is done affordably, he added.

The departure of former Chairman Richard Glick means that FERC is at a 2-2 partisan split among its four remaining commissioners, but Phillips told EBA that would not stymie its efforts. (See *Glick Bids Farewell to FERC*.)

"I submit to you that when it comes to doing important things, really important things, for our nation, we are not as divided as politics might suggest," Phillips said. "I think there is a real opportunity if we approach each other as colleagues, and with respect."

Republican Commissioner Mark Christie had echoed that sentiment earlier at the EBA meeting.

"I'm not a math wizard at all — I majored in history — but the magic number is still 3," Christie said. "That's how many votes it takes to get an order out and that hasn't changed."

Christie cited some statistics that Glick compiled before his last meeting in December, including that 98% of the orders under the previous chairman were voted out with four or more votes.

But Christie also conceded that there are contentious issues such as the natural gas pipeline certificate policies that the Democratic majority proposed last year over his and fellow Republican Commissioner James Danly's objections. However, most of the work before FERC is under the Federal Power Act, he said, and he did not see any partisan splits stopping that from moving forward.

FERC Acting Chairman Willie Phillips addressing the Energy Bar Association | *© RTO Insider LLC*

FERC Commissioner Mark Christie joins remotely | *© RTO Insider LLC*

Phillips also touched on geopolitics, saying that while the people of Ukraine have obviously suffered the most under Russia's invasion, its effects have been felt throughout the energy industry as the war scrambled global supplies and has contributed to price spikes.

Europe, many countries in which used to rely on Russian sources of energy to meet a significant amount of their demand, has seen the worst of that, with talk earlier in the year of running short on resources that require significant energy to produce, such as fertilizer and steel.

"And it was a real concern talking to my European colleagues, that that was going to impact us here," Phillips said.

Keeping the lights on will continue to be a priority for Phillips, as he cited the need to plan for extreme weather, as seen over the holidays, and increase the security of the grid against both cyberattacks and physical attacks, especially after the recent shootings of substations in North Carolina and Washington state.

"What is clear is that we've had, yet again, a wakeup call," Phillips said. "Another wakeup call that threats to our bulk power system ... are real; that they require us at FERC to refocus our efforts on reliability and resilience."

At both events, Phillips recalled his childhood in Alabama, telling EBA that being named to run FERC is the "greatest time in his career."

"I know the impact that agencies like the D.C. Public Service Commission and the Federal Energy Regulatory Commission can have on the individual; on the family; on the community," he said at the PSC summit. "And so, as a regulator, I think it is incumbent upon us to make sure that we do all that we can to build our power to make sure that those people from underserved communities; that they have a voice; and that we take that voice into consideration and make our decisions in a meaningful way." ■

FERC/Federal News

Phillips Presides over 1st FERC Meeting as Chair

Acting Chair Announces Roundtable on Environmental Justice for March

By James Downing

Acting FERC Chairman Willie Phillips speaks to reporters after leading his first open meeting. | *© RTO Insider LLC*

Acting FERC Chairman Willie Phillips presided over his first open meeting Thursday, announcing a roundtable on environmental justice and his key staffers.

"I have to tell you, never in a million years would I think that somebody like me would lead an agency for the United States government, [coming] from a place like where I am from," Phillips said.

Phillips is just the fourth African American to serve on the commission, and he often talks about his upbringing in rural Alabama and how it influences his work as a regulator. His priorities remain reliability, transmission, and environmental justice and equity issues, he said.

Phillips plans to move forward with FERC's work on improving its transmission planning policies that started under his predecessor, Richard Glick, including efforts to improve the interconnection queues, changes to regional planning, cost management and interregional transfer capability.

On environmental justice and equity, Phillips announced a commissioner-led roundtable that will be held March 29 and is meant to further the goals of FERC's Equity Action Plan issued last year that aims to reduce barriers to meaningful participation by underserved communities.

"This will provide an opportunity for FERC to hear from stakeholders on how the commission can better incorporate environmental justice and equity considerations," Phillips said. "Growing up in rural Alabama, I know firsthand the effect that government can have on communities. It is important that we consider the voices of historically disadvantaged communities in our decisions."

Phillips' staff is led by FERC's new chief of staff, Ronan Gulstone; Senior Transmission Counsel Karin Herzfeld; and Senior Legal Adviser Stacey Steep, who will focus on energy projects and permitting. All three worked for Phillips when he was a commissioner, with Gulstone coming over from D.C. government and the other two joining his staff from other offices at FERC.

Commissioners James Danly and Mark Christie briefly offered their congratulations to the new chairman in their opening comments. The meeting began on time and lasted only about an hour; Danly noted that he did not file any dissents on any of the orders issued.

Somber Comments from Clements

Speaking to reporters after the meeting, Phillips was optimistic about advancing the commission's more controversial initiatives begun under Glick.

"Throughout my whole legal career, I have made a point of making a priority of consensus building," he said. "That is how I cut my teeth working at NERC; it is a consensus-based organization. ... You may have noticed that I haven't any dissents since coming to FERC. ... When I believe something is important to me, I work hard to meet my colleagues where they are and get it in the majority. I think that's possible because I've done it, and I have no doubt that we can do it again, together."

He also balked at a question of whether the commission would wait for a fifth member to continue work on the natural gas pipeline certificate policy proposals issued under Glick.

"As a global matter, we're not waiting on anything. We're moving forward. The commission will not sit on our hands."

Commissioner Allison Clements, however, was more somber about the situation FERC finds itself in now.

"It's an unfortunate set of circumstances that leave this chair next to me being empty today," Clements said. "One thing we've learned over the last few months is that, because of the important work FERC does and the issues our jurisdiction spans, this agency has moved beyond the time when it got to stay out of the broader political limelight. So, the question for me, then, is how to bring forward, into this new normal, successful approaches to achieve our statutory responsibilities."

While most orders FERC issues are done unanimously, the reality is that the hard orders that do lead to disputes among the commissioners are often the cutting edge of a changing industry that has be overseen with an "outdated and undermatched" regulatory framework.

Dealing with those thornier issues is still possible, and Clements said FERC should renew its commitment to technology neutrality and use "data-driven decision-making."

"Only when we are willing to look at good data and credible studies, no matter the author, can we address reliability and cost issues in concrete terms on a forward-looking basis," Clements said. "Only when we address reliability and cost issues in concrete terms can we decide whether and how much change is needed, and where any needed change may fall on the spectrum from incremental to wholesale reform."

FERC should also prioritize the "public" in public interest, which means improving public access to it and ensuring transparency.

"It means fairly considering good arguments no matter which stripe the stakeholder who makes them wears," Clements said. "And it means being open to the idea of making changes requested by stakeholders, small and large, because they make our decisions better."

Clements did not respond to a request for an interview about her comments. ■

Southeast

FERC Orders Further Southern Tariff Revisions

By Holden Mann

FERC on Thursday conditionally accepted a compliance filing by Southern Co. revising its formula rate protocols, which FERC said are unjust and unreasonable, and directed the utility to provide a further compliance filing in 60 days on remedying the commission's concerns (*ER22-2642*).

Southern had submitted its compliance filing in July 2022 on behalf of its subsidiaries Alabama Power, Georgia Power and Mississippi Power in response to a FERC show-cause order, issued last March, that raised concerns about the formula rate protocols filed in Southern's tariff. (See *FERC Issues Southern Show-cause Order on Rate Protocols*.)

The commission ordered the utility to address deficiencies with the protocols in three areas: scope of participation; transparency of information exchange; and ability of customers to challenge transmission owners' implementation of the formula rate.

Utility Proposed Multiple Changes

In its filing, Southern updated the protocols to clear up each issue.

Regarding the scope of participation, FERC had directed Southern to "provide a definition of the 'interested parties' that can participate in customer meetings, information exchange, and challenge procedures." Southern proposed a definition that would include "customers under the tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general." It said the wording fit with established commission precedent.

For the information transparency issue, FERC said that interested parties might not be able to access information that would help them evaluate the correctness of the formula rate. In response, Southern suggested adding language that would require its annual informational filings and true-up filings to:

- provide formula rate calculations and their inputs, along with supporting documentation;
- specify the information that enables interested parties to replicate the calculation of the formula results;
- identify all material adjustments made to relevant data in determining formula inputs; and
- provide underlying data for formula rate inputs that require greater granularity.

Southern also proposed revisions that would allow interested parties to request information and documents necessary to determine the effect of an accounting change, to see if the annual filing includes appropriate data, and to assess the prudence of costs and expenditures. Additional new language would provide for annual meetings regarding the informational filings and joint meetings with other transmission owners. It would also address reorganizations and mergers that affect the inputs to the formula rate.

Addressing other FERC concerns, Southern added language detailing the issues that can be challenged during the review period, procedures for formal and informal challenges, protocols for appointing representatives to work with parties that submit a challenge, and processes for elevating an informal challenge to a formal one.

Clarification Still Needed

FERC accepted most of Southern's revisions but identified remaining deficiencies that still must be addressed.

The commission noted that the language related to posting of the annual update filings does not include a provision for notification of the filing via email and ordered Southern to add language to that effect.

FERC also said Southern's proposed true-up filing timeline seemed to require the filings be published by May 1 of the year following the relevant rate year. The proposed protocols, however, require interested parties to file informational requests by Aug. 1 of the rate year. That would be impossible if the filing was not available until the following year, FERC said.

Southern Company's headquarters in Atlanta | *Shutterstock*

The commission required Southern to correct the error.

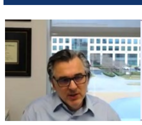
Regarding the challenge procedures, FERC said that "the lack of provisions in Southern's protocols to post all information requests, responses to information requests, informal challenges, and informal challenge resolutions [online] could limit" the ability of interested parties to "fully participate in the formula rate process." It ordered the utility to add a requirement that all relevant information be made available online.

Finally, the commission said that Southern's proposed timelines for making formal challenges "may not allow interested parties adequate time" to respond. It directed Southern to "propose a date for any interested party to submit an informal challenge … as well as … a formal challenge … after being given a reasonable period of time to review Southern's responses to the informal challenges."

The commission set 15 days as the minimum acceptable time between responses to information requests and informal challenge submission deadlines, and 31 days between responses to informal challenges and formal challenge submission deadlines.

Southern is required to submit its compliance filing within 60 days of the date of the order. The original compliance filing is conditionally accepted, effective July 23, 2022, pending its receipt. ■

Southeast news from our other channels



SERC Forum Touts Internal Communication in Enforcement

ERO Insider

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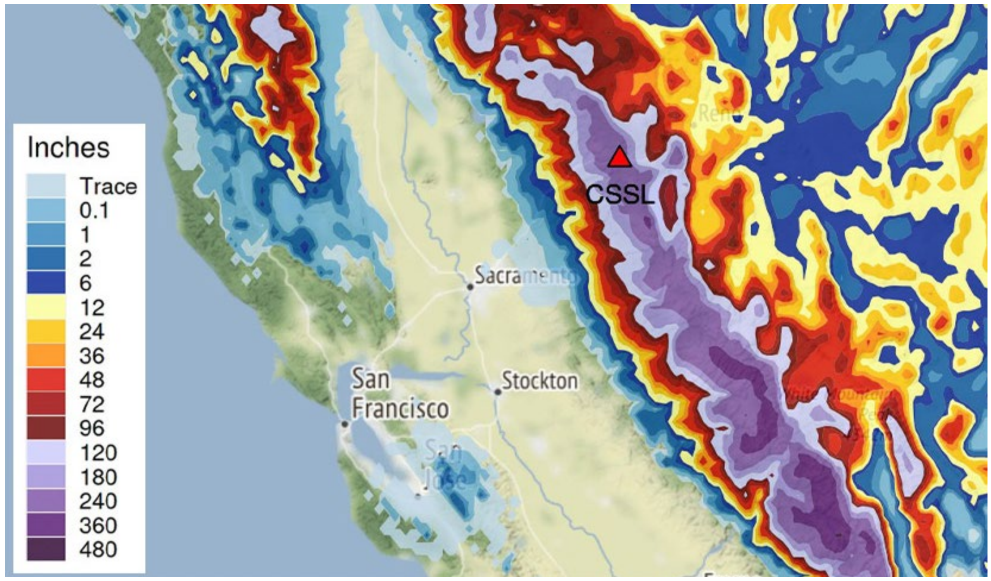
California Storms Alleviate Drought, Damage Grid

By Hudson Sangree



Snowfall in the Sierra Nevada has exceeded 200% of the seasonal average, with accumulations of 30-40 feet at higher elevations. | *UC Berkeley Central Sierra Snow Lab*

SACRAMENTO, Calif. — After three weeks of torrential rains and high winds from a series of atmospheric river storms, California started to dry out last week, with sunny skies forecast for at least the next 10 days.

The storms that began Dec. 26 caused widespread flooding and power outages as winds toppled thousands of power poles and trees. They also refilled hydroelectric reservoirs severely depleted from three years of drought and built snowpack in the Sierra Nevada that in some areas is nearly 300% greater than normal for this time of year. The state relies on that snowpack as it melts during the dry months from May to October for hydroelectric generation, farming and residential use.

In San Francisco, which bore the brunt of the storms as they flowed in succession from the central Pacific, more than 18 inches of rain fell since Dec. 26, making it the "wettest 22-day period since Jan. 14, 1862," the National Weather Service said. (The prior record-holding period was known as the Great Flood of 1862, when weeks of January rains caused rivers to overflow their banks from northern Oregon to Southern California.)

In the Sacramento area, at least 599,000 customers lost power as 1,800 power lines were downed in the 10 days after New Year's Day, the Sacramento Municipal Utility District reported. The four storms that hit during that period were the most damaging string of storms in the utility's 100-year history, with the "largest mobilization of personnel and restoration crews ever," SMUD said. More than 300 power poles were toppled — each of which takes a full crew eight hours to replace — and 650 trees fell or broke, SMUD said.

"Due to extensive damage, many customers have experienced lengthy outages that last overnight, and some will last several more days," the utility said in a Jan. 10 news release. "SMUD has been contacting vulnerable customers we expect to be out of power overnight directly so they can make arrangements."

Pacific Gas and Electric also said it mobilized its largest storm response in company history to restore power to 1.6 million customers who lost power in the first two weeks of January.

"PG&E has more than 5,000 dedicated personnel currently responding to the storm, including contractors and mutual aid from Southern California, Canada, Colorado, Idaho, New Mexico, Oregon, Utah, Washington, Wisconsin and Wyoming, with additional resources expected to arrive and assist in the coming days," the utility said in a Jan. 9 statement. "Hundreds of PG&E employees are serving in the company's Emergency Operations Center as well as in regional and divisional emergency centers."

Flooding in low-lying areas and the threat of mudslides in coastal hills led to evacuations in Sacramento County and Santa Barbara County, respectively, while the Monterey Bay area was pummeled by huge waves and nearly cut off from the rest of the state by swollen creeks and rivers.

In addition to destruction, the storms brought badly needed precipitation to California after three years of drought that undercut hydropower, adding to the state's summer resource shortfalls and near blackouts.

Lake Oroville, the state's second-largest hydroelectric reservoir with more than 3,500 acre-feet of capacity, had filled to 105% of its historical average as Jan. 17 and stood at 58% of capacity. Three weeks ago, the lake held 74% of its historical average and 39% of its capacity. It had run so dry in the drought that generation ceased in July 2021 for the first time since Oroville Dam was built in the 1960s.

Eight of the other major reservoirs operated by the state Department of Water Resources (DWR) had filled to their historical averages on Jan. 17 after years of depletion. Seven others that remained below average included Lake Shasta, the state's largest man-made reservoir with a capacity of 4,552 acre-feet. But the lake had refilled to 84% of its historical average and 53% of its capacity; three weeks ago, it was at 57% of its historical average and 34% capacity.

Snowpack numbers were even more impressive. After three years of nonexistent or quickly vanishing snowpack, much of the Sierra Nevada Mountain range was buried in 30 feet of snow. The Northern Sierra had 202% of the region's historical average snowpack on Wednesday; the Central Sierra had 253%; and the Southern Sierra had 292%, DWR reported.

All three areas already had met or exceeded 100% of average snowpack for April 1, a key date in state water planning for summer. The Southern Sierra had 148% of average snowpack for April 1, and the Central Sierra had 128% of average.

On Jan. 10, the U.S. Drought Monitor removed much of the state from "extreme" and "exceptional" drought conditions, which had persisted through December. Moderate and severe drought still grips most of California.

Whether the snowpack lasts until it's needed in the dry months remains in question. After a wet December 2021, 2022 saw the driest January-March period on record. State water officials have warned that more storms are needed to ensure an adequate water supply this year. ■

Parties Protest PG&E Plan to Spin off Generation

By Hudson Sangree

Pacific Gas and Electric is getting pushback on its proposal to place most of its generation fleet into a new company and to sell nearly half of the firm to investors after seeking FERC approval for the plan last month (EC23-38).

"Pacific Gas and Electric Co. submits this application requesting commission authorization for a proposed transaction whereby PG&E will transfer substantially all of its non-nuclear generation assets to its new wholly owned subsidiary, Pacific Generation LLC, which jointly with PG&E will provide cost-based generation service to retail customers within PG&E's existing service territory," the utility said in its Dec. 13 *application* to FERC. "The transaction will facilitate a subsequent sale of up to 49.9% of the equity interests in Pacific Generation to one or more third-party investors."

PG&E valued the assets — 5.6 GW of hydroelectric dams, solar arrays, natural gas plants and utility-scale battery installations — at $3.5 billion. The facilities include its 182.5-MW Elkhorn Battery project, one of world's largest battery arrays, and the 1,212-MW Helms Pumped Storage Project, considered an engineering breakthrough when it came online in 1984.

Once PG&E transfers the generation fleet to Pacific Generation, it intends to issue a long-term debt of up to $2.1 billion on the assets to refinance existing debt.

The company contended the transaction will "strengthen PG&E's financial condition; allow PG&E to more efficiently access equity capital to fund significant capital requirements to improve the safety and reliability of its system; and be consistent with PG&E's path to an investment-grade credit rating."

Its stock and credit rating plunged following a series of catastrophic wildfires in 2017-2018 and its filing for bankruptcy reorganization in January 2019. The utility's stock has recovered some of its former value, hovering in the $15 to $16 range since October, but it remains far below its peak of more than $70/share in August 2017.

PG&E requested expedited FERC approval by March 1 because it intends to initiate its sale to investors before the end of the first quarter.

The utility filed a similar application with the California Public Utilities Commission (CPUC) in September, also seeking expedited review.

The assets PG&E plans to sell include the 182.5-MW Elkhorn Battery project, one of the world's largest battery arrays, on California's Monterey Bay. | *EKM Metering*

Both applications earned protests from cities, consumer groups, community choice aggregators and the Transmission Agency of Northern California (TANC), which serves publicly owned utilities. Most of the protesters urged FERC and the CPUC to slow down the approval process to gather more information and assess whether the plan is in the public interest.

"As transmission customers, TANC and its members that require PG&E or CAISO grid transmission are concerned that the proceeds from the proposed sale will not benefit PG&E transmission customers," the agency wrote.

It urged FERC to find PG&E's application deficient and require the utility to explain how it valued its generation assets at $3.5 billion and decided that Pacific Generation could take on $2.1 billion in long-term debt.

Public Citizen, a consumer advocacy group, told FERC that PG&E shouldn't be allowed to monetize its ratepayer- funded generation fleet after causing a series of catastrophic wildfires.

"PG&E justifies using consumer-funded assets as a mechanism to raise assets because of financial pressures stemming from the company's 2019 bankruptcy (from which it emerged in 2020)," the group said. "But PG&E's financial challenges stem not from bad luck, but from the corporation's repeated criminal negligence."

The company was convicted of violations related to the 2010 San Bruno gas pipeline explosion that killed eight people and pleaded guilty to 84 counts of involuntary manslaughter for its role in starting the 2018 Camp Fire, which destroyed the town of Paradise.

"Consumers should not bear risk because of PG&E's repeated criminal malfeasance," it said.

In addition, Public Citizen said the utility had "failed to provide documentation and analysis necessary for the commission to determine if such a proposed transaction will result in just and reasonable rates, or will harm consumers."

"As a publicly traded company, PG&E has a number of other less disruptive means to raise capital," it said. "To ensure conformity to just and reasonable rates, the commission should require PG&E to provide analyses of alternative capital-raising strategies, including the impact on ratepayers of issuing more shares. PG&E's sole proposal — selling off equity in rate-base generation — prioritizes investor benefits at the expense of risk to consumers."

Parties expressed similar concerns before the CPUC, urging the state regulator to take more time to consider the full ramifications of PG&E's proposal.

For instance, The Utility Reform Network (TURN) said PG&E's application involves at least 50 issues that need to be resolved, including 42 identified by PG&E in its application. TURN highlighted eight additional issues, including whether the deal would leave PG&E and Pacific Generation too deep in debt and whether its benefits would flow to shareholders and not ratepayers.

"The resolution of many of those issues requires complex financial modeling to demonstrate whether PG&E's asserted financial outcomes are likely to be realized, or whether PG&E's proposal introduces additional financial risks," TURN said. "The consideration of these serious implications should not be glossed over for potential shareholder benefits. ...

"As part of its application, PG&E requests an expedited schedule and claims that the request is justified because there is a 'need to resolve a financial matter expeditiously to avoid ratepayer harm,'" the group said. "As an initial matter, the only 'financial matter' here is one that is being created by PG&E itself, not by external forces or circumstances."

It asked the CPUC to extend its briefing schedule, postponing a decision in the matter until at least later this year. ■

CAISO/West News

FERC Approves PSCo's Temporary CO2 Price

Carbon Price in Place Until Utility Joins WEIS in April

By James Downing

FERC last week approved Public Service Company of Colorado's (PSCo) request to use the social cost of carbon to help dispatch its generation for the next few months (*ER23-158-001, et al.*).

The utility has to use the price on carbon to limit the use of its highest emitting power plants under Colorado's clean energy law. The price on carbon has to be factored into its generation dispatch until PSCo joins an "organized energy market," which will occur April 1 when it joins SPP's Western Energy Imbalance Service (WEIS) market.

Once in the WEIS, a price on carbon will no longer be used because the energy market does not price that externality.

The carbon price will only be applied to plants that PSCo owns or contracts with, not spot purchases. The utility told FERC that the carbon price should make more carbon-intensive generation dispatched less often, leading to natural gas and renewables being used more than they would have otherwise.

The carbon price is expected to raise PSCo's systemwide production costs by about $8.3 million over the first three months of this year. The wholesale customers that fall under FERC regulation will wind up paying $664,000 of that, PSCo said.

FERC found the request to be just and reasonable. Including the state-determined social cost of carbon in its generation dispatch will allow PSCo to meet Colorado's energy policies, the commission said.

Holy Cross Electric Association asked FERC to reserve the right to reopen the case if PSCo does not join the WEIS as scheduled, but the commission said the cooperative failed to explain why continuing to use the carbon price in such a situation would be unjust and unreasonable. If it does become so, Holy Cross or any other entity would be able to file a complaint at FERC and prove that, the commission said. ■

Tri-State's Craig station | *Jimmy, CC BY-SA-2.0, via Wikimedia*

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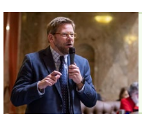

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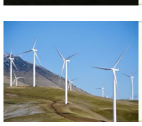

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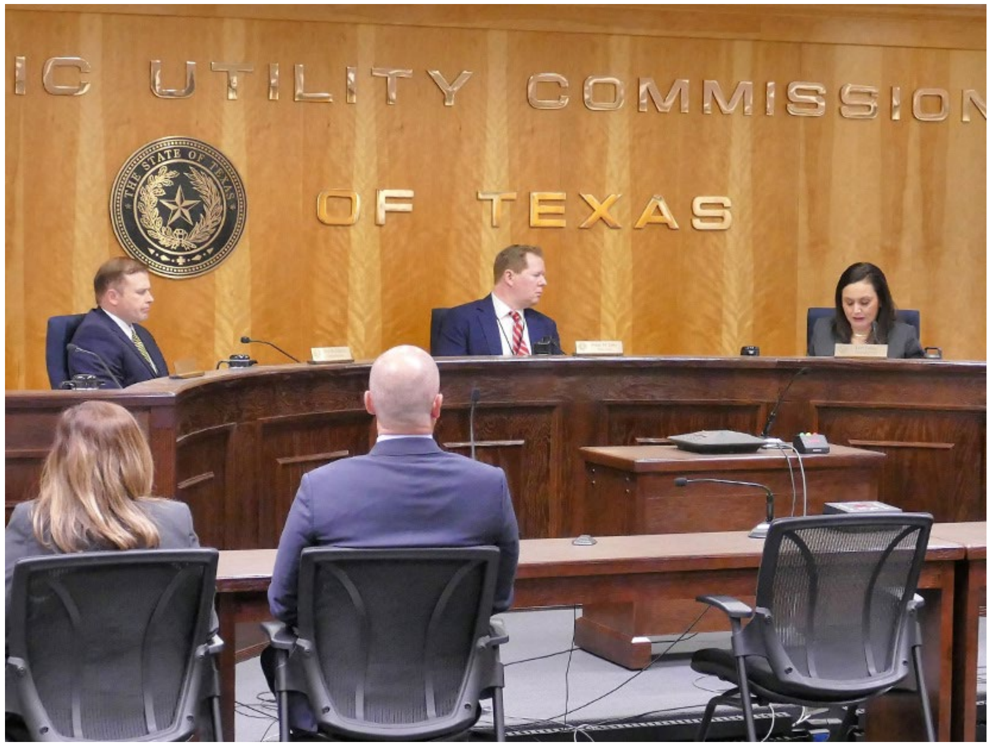
ERCOT News

Texas PUC Submits Reliability Plan to Legislature

By Tom Kleckner



The Texas PUC discusses ERCOT's proposed market redesign. | *© RTO Insider LLC*

The Texas Public Utility Commission on Thursday unanimously agreed to the principles necessary to replace ERCOT's energy-only market with a performance credit mechanism (PCM), sending the proposal to an uncertain fate in the legislature.

Chair Peter Lake guided the commission through a discussion and then an editing session of his "underlying foundation" for the mechanism. The commissioners summarized the proposal in a four-page memo attached to the *order* (Project 53298).

The PCM has been criticized by some as a sop to the market's generators. It would reward them with credits based on their performance during a determined number of scarcity hours. Those credits must be bought by load-serving entities, based on their load during those same hours, or exchanged by LSEs and generators in a voluntary forward market.

The commission ordered PUC staff and ERCOT to delay implementation of the PCM "until such time as the 88th Legislature has had an opportunity to render judgment on the merits of the PCM and/or establish an alternate solution."

The recommendation fulfills the PUC's statutory obligation under *Senate Bill 3*, enacted following February 2021's deadly winter storm. It completes a process that began in December 2021 and involved work sessions, stakeholder feedback and industry criticism. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

But State Sen. Charles Schwertner (R), author of SB3 and chair of the Business and Commerce Committee, *tweeted* that the PUC "chose to ignore the clear direction of the [Texas Legislature] by voting to replace the state's competitive energy market with a costly and complex proposal that is unlikely to deliver the dispatchable generation resources that Texas needs. It's unacceptable."

In a letter to the commission last week, Schwertner said it would be "imprudent" for the commission to act without the legislature's "consultation and collaboration." (See *PUC Closes in on ERCOT's Market Redesign*.)

The commission's revised memorandum said it would open a project "to evaluate and establish an appropriate reliability standard" based on the PCM concept outlined in a *report* by consultants Energy and Environmental Economics (E3). The firm evaluated six alternatives but did not recommend the PCM, saying it would be too complex and costly, estimating the credits could cost retailers $5.7 billion a year. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

"Once implementation is launched at some point in the future subject to consideration and direction of the 88th Legislature, the commission will develop an implementation plan," the PUC said in its memo.

It said the plan will identify which entity — including among the commission, ERCOT and the Independent Market Monitor — will be responsible for analysis related to each of 17 "decision points," including such details as the PCM compliance period and the number of hours per compliance period.

"For decision point items relegated to ERCOT analysis, the commission will direct ERCOT to undertake stakeholder evaluation subject to ERCOT board vote for ultimate recommendation for commission approval," the commission said. "The ultimate authority for all of these and any additional decision points lies with the commission."

The commission also tasked ERCOT with evaluating "bridging options" to retain existing assets and build new generation until the PCM can be fully implemented. It said the grid operator should report at the commission's open meeting this Thursday with a proposed date for delivering a report detailing the options ERCOT considered, its board's preferred solution and implementation steps.

"I think this reflects a deliberative process on the part of the commission," Commissioner Will McAdams said. "I said a year and a half ago that I think our finest hour is to come, and this is part of it. It's a good product, and we need to be able to defend it."

Reaction

Others weren't so sure.

Katie Coleman, TIEC | *© RTO Insider LLC*

"It was difficult to know what they were talking about," Katie Coleman, who represents Texas Industrial Energy Consumers, said after the meeting but before the edited memo was posted. "The PCM they voted on today is not the PCM in [the consultant's November] report."

Coleman, who has testified several times

ERCOT News

before lawmakers and the commission about market designs, noted various legislative committees have requested in multiple hearings that they be given a construct they can consider.

"They're trying to redesign a market that's been in place for two decades on the fly in an open meeting. It needs a lot more work and thought than what's been put into it so far," Coleman said. "This proposal ... seems to have changed substantially behind closed doors since [November].

"All of the things they discussed today are hallmarks of a capacity market. It's turning into a game of semantics," she added.

Stoic Energy's Doug Lewin *labeled* the mechanism a "Pretty (much a dressed up, overcomplicated) Capacity Market."

"ERCOT will have a capacity market replacing the only competitive energy market in the U.S.," Demand Control 2 founder Chris Hendrix *tweeted*. Demand Control works with market participants to help them access the wholesale market.

"My other concern with pushing some decisions to ERCOT is that Chairman Lake and the ERCOT board and senior staff do not have any retail electricity expertise," he told *RTO Insider*.

TIEC last week *asked* the PUC to reconsider its December order approving ERCOT's amended and restated bylaws. The changes limited the ability of corporate members and market participants to recommend policy and procedural changes and to vote on governance matters. (See *ERCOT Board of Directors Briefs: Dec. 19-20, 2022*.)

Demand Control 2, San Antonio's CPS Energy and generation investor Eolian on Jan. 17 also *filed* a joint rehearing request with the PUC (*54444*).

The Texas Association of Manufacturers said it was "concerned with today's action by the PUC to approve a novel proposal that is not well understood, and has not been modeled, but appears to be designed to ensure a certain profit level for existing generation."

The group has proposed additional state-backed financing for dispatchable development, temporary property tax cuts for new or modernized dispatchable facilities and a reliability service that "directly rewards" new, flexible generation. "Specifically, we support proposals that ensure market revenues would remain performance-based, consistent with the current deregulated market design, and would avoid a government-mandated capacity market or other similar electricity taxes or fees to support incumbent generators," it said.

The Texas Competitive Power Advocates, representing large generators that have promised to build 4.6 GW of additional capacity if the PCM is adopted, commended the commission's work. In a statement, Executive Director Michele Richmond said the mechanism will make it "economically viable for companies to invest in the new dispatchable generation needed during periods of low renewable output in ERCOT."

"The PCM builds reliability into the successful competitive market in Texas," Richmond said. "Paying for the reliability that ERCOT needs to power Texas when the wind isn't blowing and the sun isn't shining, but without paying resources for merely existing."

PUC Coalesces Around PCM

The commissioners signaled their intentions in a *filing* made Wednesday evening. Lake, McAdams and Kathleen Jackson expressed their outright support for the mechanism, but Lori Cobos and Jimmy Glotfelty offered a little pushback.


Commissioner Jimmy Glotfelty | © *RTO Insider LLC*

"My hesitation with the [PCM] is ... we will shift up to $5 billion per year more for something we are getting today: a reliable system. Rising and falling prices are not inherently crisis-based models, but economic principles," Glotfelty wrote, referencing Lake's frequent comment that "the cure for high prices is high prices."

"Over the last 25 years, high prices have led to new investment in transmission and generation all over this state to the benefit of consumers and the environment," Glotfelty added. "Our ERCOT market has become, arguably, almost too efficient for the value of this much needed commodity."

During Thursday's work session, Glotfelty pushed to include evaluating best practices to mitigate market manipulation and guarding against self-dealing and market power abuse in the centrally cleared market.

Cobos focused her comments on "near-term actions to help retain our existing long-duration, dispatchable thermal generation fleet" needed to maintain reliability during multiday extreme weather events. She pushed for replacing reliability unit commitment practices and letting the operating reserve demand curve work "to send market signals for new dispatchable generation investment." ■

MISO News

MISO Actions During December Storm Spark Debate

By Amanda Durish Cook

MISO's emergency declaration during the December winter storm has ignited a debate over whether the RTO should issue the alert to sustain its neighbors during extreme weather.

The grid operator in December made the emergency declaration as a wintry blast forced generation outages and higher than forecasted load in the system, pushing MISO into a three-hour maximum generation emergency to use its collection of load-modifying resources. It lifted a maximum generation warning for its South region a few hours before the evening peak. (See FERC, NERC Set Probe on Xmas Storm Blackouts.)

Jason Howard, MISO's director of operations and risk management, said during a Reliability Subcommittee meeting Jan. 17 that staff and members "successfully managed through the event."

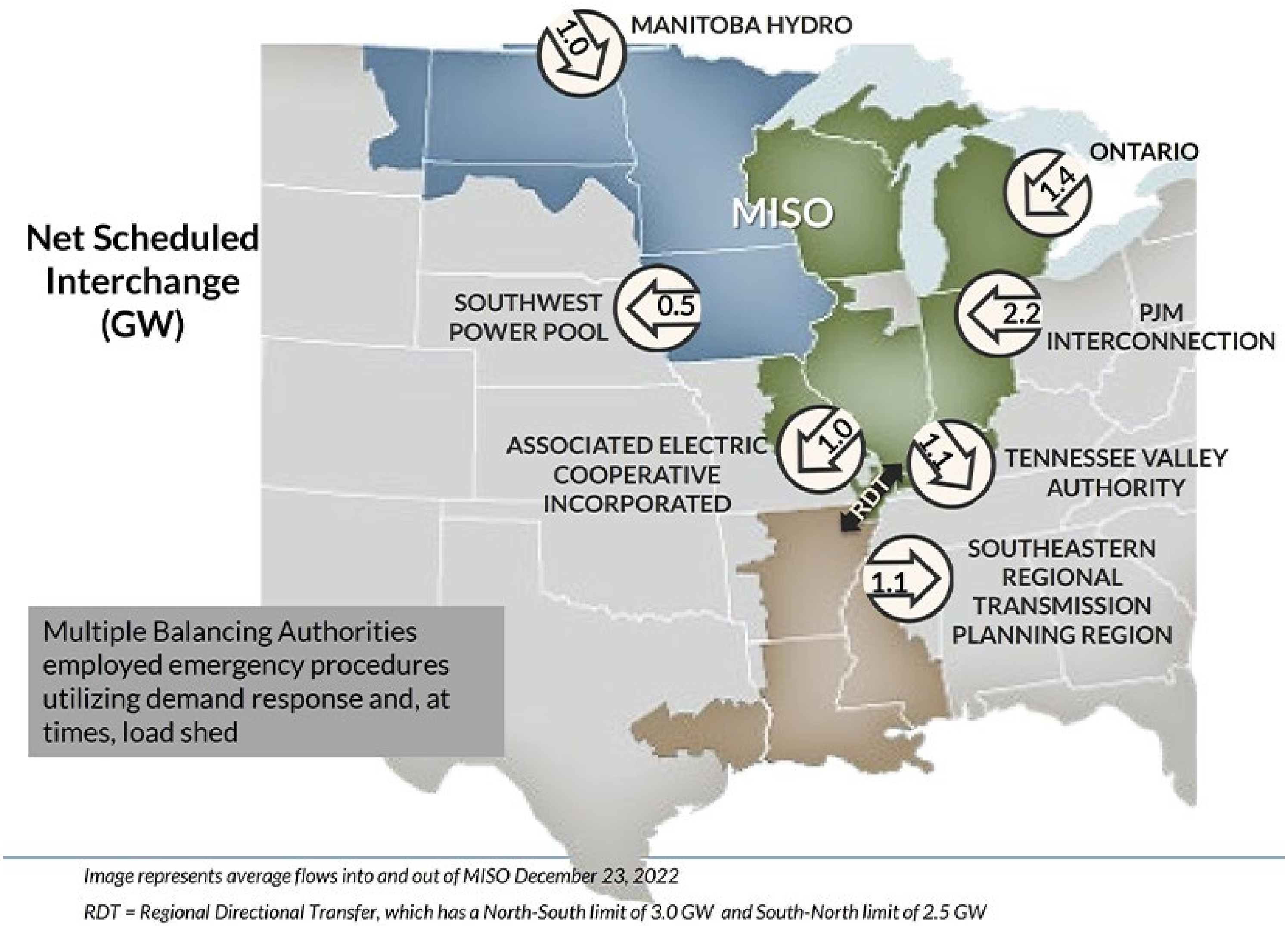
However, he said the emergency was necessary to manage reliability while the RTO provided a "significant amount of exports" to its neighbors. Howard said staff was able to access additional capacity once they declared the emergency.

"There wasn't a concern for capacity," he said. "It was a matter of maintaining reliability and helping our neighbors out. [There was] no disruption of power to the MISO footprint."

Howard said staff felt "very comfortable" with its capacity position ahead of the storm but that MISO and the industry "struggled" with forecasting an "unanticipated, drastic increase in demand. He said the gas generation fleet began depleting its supply as the system entered the evening peak on Dec. 23.

The emergency decision was ultimately necessary to "get at emergency reserve to maintain sufficiency and export upwards of 4 to 5 GW to help our neighbors," he said, referring to SPP, the Tennessee Valley Authority, Associated Electric Cooperative Inc. and the Southeast planning region. Howard said MISO had a responsibility to act because some of its neighbors were either facing or actively in load shed.

Director of Market Administration John



Average flows into and out of MISO on Dec. 23 | *MISO*

MISO News

Harmon said MISO was simply "assisting in an emergency," as it would want to similarly be aided during an emergency.

Independent Market Monitor David Patton said he was still reviewing the event, adding that his initial conclusion is MISO should define what lengths it's willing to go to in helping neighbors at the expense of its own markets.

"I will say that I totally appreciate and agree with the notion of wanting to help your neighbors, but you should be following your operating procedures," Patton said. "The action that any RTO takes to help a neighbor can have serious financial impacts for customers."

Stakeholders debated whether the grid operator should call on load-modifying resources to support non-firm exports. Patton said LMRs to support exports can trigger shortage pricing "that could cost millions."

Hwikwon Ham, with the Minnesota Public Utilities Commission, pointed out that MISO's risk assessments depend on imports from PJM and Canada to help keep the footprint afloat.

Minnesota Power's Tom Butz said that had MISO not helped TVA during its emergency, the ramifications might have been more dire than a matter of "economic convenience."

"This is a first for MISO," Howard said of MISO's status as a net exporter during the weather event. He said staff is going to have to determine its "operational philosophy" regarding emergency procedures in aiding neighboring regions.

MidAmerican Energy's Dennis Kimm argued that MISO's issue in December wasn't a gas supply one, but a timing problem. He said staff didn't commit gas generators ahead of time, thus failing to provide them enough time to secure additional supplies. Kimm said gas purchases are especially challenging to procure during a holiday weekend and after 5 p.m.

Stakeholders asked whether MISO might consider clearing additional gigawatts of gas generation in the day-ahead market to serve as a buffer when extreme temperatures are forecasted.

Staff said MISO's five-year plan includes devising methods to better manage uncertain conditions. Howard said they are working on providing its members better situational awareness so they can make more informed decisions on fuel procurement.

Howard acknowledged "issues" with sending notifications to market participants on Dec. 23 and said that the RTO is examining the communication issues to see what went wrong.

He said the winter storm's high pressure kept MISO's wind production high, unlike the February 2021 winter storm that brought in a low-pressure system. "These are unique differences that we have to manage that makes the planning challenging," he said.

Staff said their first report on the storm contained only preliminary findings but promised more discussions on the system's performance in December. The Resource Adequacy Subcommittee is planning to discuss the storm and its implications on capacity accreditation during its March meeting.

MISO issued a cold-weather alert and conservative operations instructions for its South region Dec. 22 to 26. It also declared conservative operations for its North and Central regions and two local transmission emergencies because of congestion on Dec. 23.

Staff said the South region's warning was necessary because of a request by joint parties to the regional transmission transfer between the Midwest and South regions that MISO reduce flows across the link. Staff said they were still in discussions with the utilities to understand why the request was made.

Factoring in exports, MISO served peak demand of 111 GW on Dec. 23. Its load averaged 78 GW during December. ■

MISO: Too Early to Gauge 2023-24 Capacity Supply

By Amanda Durish Cook

MISO told stakeholders Jan. 17 that it is not yet able to make "quantifiable conclusions" about the amount of capacity available for the 2023-24 planning year after completing its first seasonal Planning Resource Auction (PRA) in April.

"From the supply side, it's very early in the process to begin making predictions," Eric Thoms, senior manager of resource adequacy operations, said during a Resource Adequacy Subcommittee meeting. He said many load-modifying resources have not yet begun the registration process and some generators haven't completed verification test capacity data.

Stakeholders asked the grid operator to publish more frequent and precise supply data before auctions are conducted, a result of a 1.2-GW shortfall across MISO Midwest in last year's PRA. MISO leadership has said there will be more capacity shortfalls in future auctions unless members quickly bring more generation online. (See "Stakeholders Ask for Data Improvements," *MISO Promises Stakeholder Discussions on Capacity Auction Reform*.)

Thoms said reserve requirements will likely look the same by the time the auction rolls around. Staff currently *estimates* the RTO will need 132 GW to meet summer load, 125 GW to cover the fall, 127 GW for the winter and 124 GW for the spring. MISO's preliminary numbers show that several of its 10 local resource zones will require more reserves for non-summer seasons, a first for the footprint.

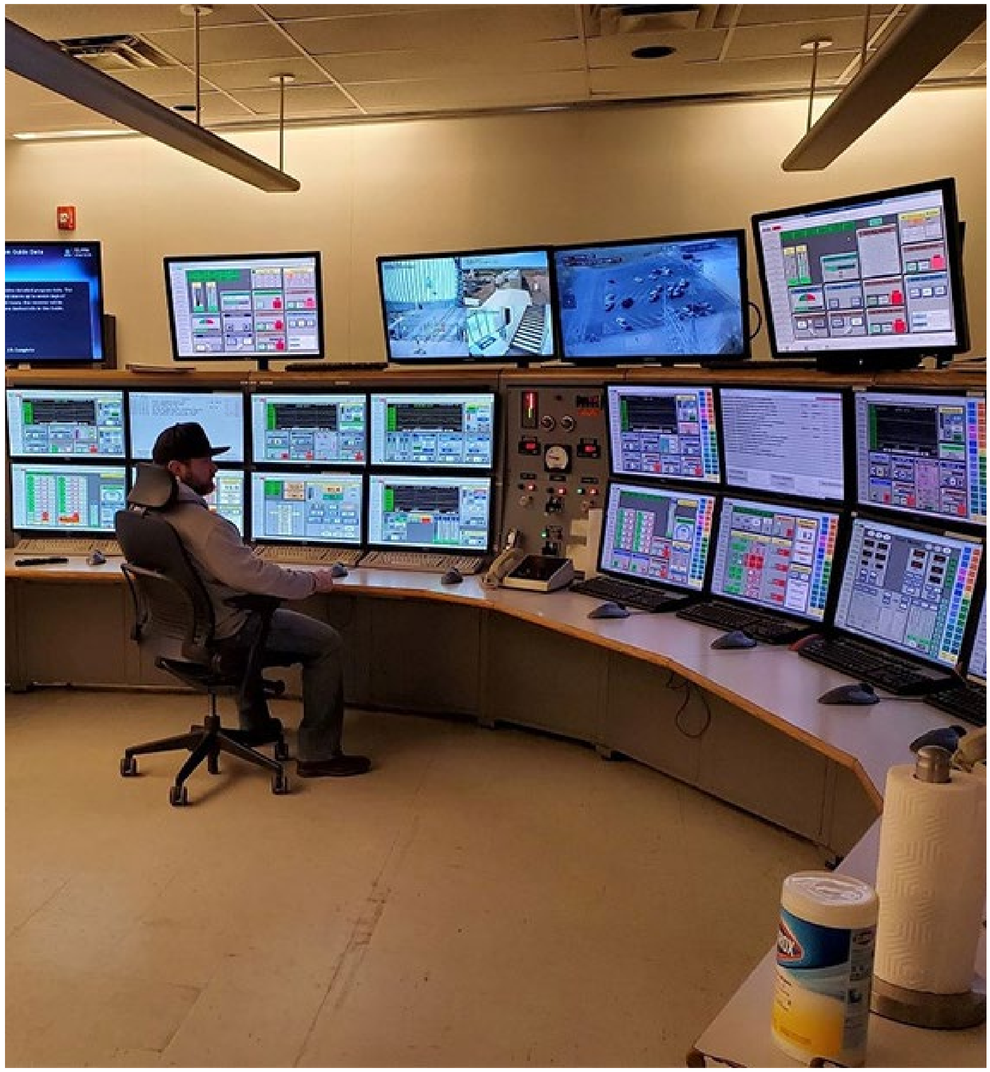
The grid operator's 7.4% summer planning reserve margin is lower than the 8.7% margin used in last year's PRA. Staff said the decrease was driven by switching to seasonal modeling and "changes in resource mix/performance and load factors."

Thoms said MISO is in the process of evaluating load-serving entities' load forecasts to find reasons behind the smaller forecasts. He said staff has yet to form a "narrative" on why system demand is expected to decline.

Monitor Revises Mitigation to Fit Seasonal Design

MISO's Independent Market Monitor has been prepping for seasonal auction market mitigation.

IMM David Patton has created a *website* for



An Xcel Energy control room | *Xcel Energy*

market participants to request reference levels and participation exclusions for those who don't want to offer into the auction. He said the reference level and exclusion process will be revised to account for shorter seasonal capacity periods; it will also share the penalties for accreditation suppliers that enter generation outages.

Patton said he will consider when outage penalties and diminished accreditation make it uneconomic for a resource to offer into the seasonal auction. He said he will issue exclusions when a resource's "expected penalties and accreditation costs in future planning years is likely greater than its forgone revenues." He said that non-exempt generator outages render auction participation worthless when they last more than 45 days of a 90-day season and exempt outages render participation worthless at longer than 75 days.

MISO's tariff does not allow the risk of penalties to be included in reference levels, Patton noted. He said he will not accept requests to address outage penalties in reference levels.

Patton asked market participants to submit lists by March 14 of deliverable resources they don't intend to offer into the PRA or be included in fixed resource adequacy plans.

Stakeholders requested additional time with the monitor to better understand market mitigation under a seasonal auction construct.

When asked by stakeholders whether Patton supported MISO's 2023 seasonal capacity auctions or thought they were rushed, he laughed and demurred from an answer. ■

MISO News

5th Circuit Demands Explanation from FERC on Long-pending Grand Gulf Complaints

By James Downing

The 5th U.S. Circuit Court of Appeals told FERC on Wednesday that it must explain why it has yet to rule on disputes between state regulators and Entergy that have been pending for up to six years.

The Louisiana Public Service Commission has filed several FERC complaints against Entergy's System Energy Resources Inc. (SERI), which runs plants jointly owned by the firm's different utilities, notably the Grand Gulf Nuclear Station in Mississippi.

The PSC, along with retail regulators in Arkansas, Mississippi and New Orleans, have submitted several complaints in recent years challenging SERI's rates — the oldest dating back to January 2017 (EL17-41) and the newest in 2021 (EL21-56). (See *Entergy Regulators Ask FERC to Settle Grand Gulf Dispute*.)

"The LPSC argues that consumers are overpaying SERI by about $4 million per month due to the activity alleged in one complaint," a three-judge panel *said*. "Another complaint alleges that consumers in Louisiana unjustly paid a further $360 million in costs for Grand Gulf."

The Louisiana commission went to the court to complain that FERC was taking too long in the proceedings, and its inaction was "causing irreparable injury to consumers."

While Congress never imposed firm deadlines for FERC to resolve Section 206 complaints under the Federal Power Act, "it certainly anticipated greater alacrity than this," the court said.

The Regulatory Fairness Act of 1998 holds that FERC is supposed to give Section 206 complaints the same priority as Section 205 filings, which come with firm deadlines. FERC is supposed to explain why it has not ruled on a complaint after 180 days, but it regularly ignores that requirement and did so in the Louisiana PSC's complaints, the court said.

"Despite the RFA's guidance, Section 206 proceedings before FERC appear to take much longer, costing consumers hundreds of millions of dollars and pressuring parties to settle," the court said. "The remaining LPSC complaints have gone four to six years without resolution."

FERC argued against any requirement to act on the case, saying it would allow it to skip the queue of other items pending before it. But the court said that argument concedes that the federal regulator has other Section 206 proceedings that have been pending even longer, meaning many consumers have been paying unjust rates, without hope for a refund, for more than six years.

FERC must make a filing within 21 days explaining why it has taken so long to deal with the regulators' complaints. ■

Grand Gulf nuclear station in Port Gibson, Miss. | *Entergy*

MISO News

FERC Allows One-time Bypass of MISO IC Queue Fees

By Amanda Durish Cook

FERC last week granted a waiver to several renewable energy projects that allows their developers to circumvent MISO's fee distribution after one of the projects dropped out of the RTO's interconnection queue.

The commission said in its Jan. 20 order that it granted the waiver because the project negotiations with MISO resulted in a "mutually agreeable solution" that makes the other projects whole for any increased upgrade costs after EDP Renewables withdrew its Shullsburg Wind Farm (*ER23-404*).

EDP challenged MISO's calculation of the monetary harm inflicted on three other wind farms with its withdrawal and termination of its generator interconnection agreement with the RTO and American Transmission Co. (ATC) in 2020.

When a generation project in MISO's queue withdraws, staff analyzes the financial impact on remaining interconnection requests in the same study cycle by calculating network upgrades costs that are shifted to those projects. The grid operator then uses the milestone payments made during the definitive planning phase or payments made by interconnection customers to reimburse remaining projects for any upgrade costs caused by the withdrawal.

MISO determined that five other projects hoping to interconnect to ATC's system were financially affected by the withdrawal. Two of those waived their rights because their projects were insignificantly affected.

The Shullsburg facility contested MISO's calculations and initiated an alternative dispute resolution process in 2021. Shullsburg ultimately reached a confidential agreement between it and the three remaining projects, the companies said.

MISO said it has some reservations about the agreement because the three remaining projects aren't guaranteed reimbursement unless they "make a certain type of sales to certain customers." However, the grid operator said it supports the agreement because it allows the distribution of agreed-upon harm payments to the projects.

| Allete Clean Energy

The RTO also said the agreement allows it to hold in escrow the payments Shullsburg made while in the queue until the three projects become operational. ■

Stakeholders Cry Foul on MISO's Resource Accreditation Pivot

By Amanda Durish Cook

Less than a year after debuting availability-based accreditation, MISO is proposing to reformulate how it accredits its resources.

Stakeholders aren't happy.

MISO wants to accredit all resources based on their performance during predefined resource adequacy hours, or tight operation conditions. It will then adjust unit accreditation by a capacity value determined by loss-of-load expectation. The equation's LOLE piece would replace the grid operator's use of unforced-capacity values that rely on forced outage rates.

The new design is also intended to replace MISO's current accreditation method for renewable energy, which uses a unit-level effective load-carrying capability calculation based on a peak hour contribution. It would also have staff fashioning new planning reserve margin requirements based on coincident loss-of-load hours rather than coincident peak load hours.

Jordan Bakke, director of policy studies, told stakeholders during a Resource Adequacy Subcommittee (RASC) meeting Wednesday that MISO's goal is to create a single, "comprehensive resource adequacy accreditation reform" filing with FERC by next year, though the requested effective date is up for debate.

"We're not trying to seek immediate implementation," he said.

Bakke said the grid operator wants to shift its accreditation philosophy from "peak load-based" to "risk-based" under a sampling of the system's riskiest hours.

Multiple stakeholders said they had serious concerns with the proposal, arguing that a direct loss-of-load approach should be applied to all resources. They contended a loss-of-load approach will only rely on a limited number of forecasted hours that are too small a sample to use for accreditation.

Invenergy's Sophia Dossin asked how the approach will help MISO. She said a forced-outage value is broader and based on more reliable historical — rather than forecasted — information.

Bakke said a probabilistic loss-of-load approach is better suited for the tighter operating reality MISO is facing. He said the past is not an indication of the future conditions and resource mix.

Staff said using a direct loss-of-load calculation produces similar accreditation values to unforced capacity calculations.

"My reaction to that is, 'So what?' That's almost a tautology," resource adequacy consultant Michael Milligan said.

WEC Energy Group's Chris Plante wondered whether MISO and stakeholders would be better served if they reexamined the tariff's Schedule 53, which defines the RTO's seasonal accreditation calculation.

"I think we've gone in the opposite direction of what stakeholders have intended," he said. "I think we need to ask what it is we want out of our resource adequacy construct. Do we want it to tell us when to construct generation or do we want it to tell us the reliability value of the existing fleet? And I think it should be the latter."

Entergy's Nine Mile Unit 6 in Louisiana | *Entergy*

"I think what you're hearing in this meeting today is there's not support for this proposal. And yet, you're moving forward with it anyway," Clean Grid Alliance's Natalie McIntire said.

McIntire asked why staff is proposing to change thermal resource accreditation so soon after winning approval of its availability-based method. Were they revisiting accreditation because they "didn't get it right," she asked.

"We need more. We need more here from MISO. And I think we need to take a step back and see what's needed from the stakeholder process … rather than MISO completely driving this train," McIntire said.

"I share what a lot of other stakeholders are feeling in this process: Are we going to be railroaded?" Southern Renewable Energy Association's Andy Kowalczyk said.

Staff said they will devote more time to the topic during future RASC meetings.

FERC last year approved MISO's seasonal capacity accreditation, which assigns accreditation based on a generating unit's past performance during expected tight conditions. That accreditation only applies to MISO's thermal generators; MISO has yet to file a separate, availability-based accreditation for its renewable generators. (See *FERC OKs MISO Seasonal Auction, Accreditation*, *MISO Adding Availability-based Renewable Energy Accreditation*.)

During a Jan. 17 discussion before the subcommittee, market participants complained about the difficulty of making minor adjustments to planned generator outages without taking hits to their resource accreditation. Representatives from Minnesota Power and WEC Energy Group said they have either started an approved outage early or extended it by a few days, only to entirely lose their outage exemption and negatively impact their accreditation.

Stakeholders said MISO is unfairly decrementing their availability-based accreditation for the outage's entirety and not for just the few days tacked on. They asked staff to rectify the situation and make it easier to modify existing planned outages in MISO's nonpublic interface. ■

MISO News

MISO Plans to Bar Intermittent Resources from Ramp Capability

By Amanda Durish Cook

MISO wants to exclude its intermittent class of resources from providing ramp capability by midyear.

The grid operator said last week that, in practice, dispatchable intermittent resources have not "assisted in ramping needs," referring to wind generation that's often trapped behind transmission congestion.

The RTO's ramp capability product's current design doesn't account for a resource's deliverability, staff said, adding that ensuring a deliverable ramp product will produce better price signals.

Senior Market Engineer Chuck Hansen said during a Market Subcommittee meeting Thursday that MISO wants to file with FERC in February to disqualify intermittent resources from ramp eligibility by June.

Some stakeholders argued that wind can provide upward ramping and said MISO seems to be treating certain resource types unfairly because of system congestion.

Hansen said the action is prudent in today's operating environment, but it doesn't have to be a "forever change." He said staff can revisit ramp eligibility as the fleet evolves.

In early December, Clean Grid Alliance's Natalie McIntire pointed out that ramp-capable hybrid resources with storage capability currently are forced to register as dispatchable intermittent resources because MISO doesn't yet have a hybrid resource market participation model.

MISO also wants to disable its downward ramp capability product by setting the product's demand curve price to zero. The grid operator overwhelming needs up ramping, not down ramping.

Hansen said devaluing downward ramping is a "way of turning it off without throwing it away."

"We're not ready to remove it permanently," he said. "But this is a way to disconnect the clutch, to use a metaphor."

Hansen said staff will still track down ramping in its markets but won't price it. He said from 2018 to 2022, MISO paid $542.80 in real-time payments for the downward product.

"It's not that it has not been sending useful pricing signals. It's really that it's been sending no pricing signals," Hansen said in December.

A MISO analysis showed that if it priced its downward ramp capability at zero, only 18 of 70,000 five-minute market settlement intervals would have been short on down ramp in the first eight months of 2022.

"We have an abundance of ability to ramp down. It's physics; it's always easier to ramp down," Hansen said. "We don't want to pay for something that's inherent to the system." ■

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MISO News

Financial Firm Finds MISO FTR Market Needs Work

By Amanda Durish Cook

A financial consulting firm has concluded that MISO's auction revenue rights and financial transmission rights market needs updating to keep it relevant to the changing grid.

London Economics International (LEI) said during a Market Subcommittee meeting Thursday that the grid operator's process needs a refresh, saying it is becoming increasingly outdated because its auctions rely on a 2004 benchmark rights allocation in the MISO Midwest region.

"The ARR entitlement process, though valuable, has not kept pace with new entries and resource retirements, limiting transmission customers' ability to hedge their day-ahead energy market congestion risks," LEI consultant Victor Chung told stakeholders.

MISO contracted LEI last spring to evaluate its ARR and FTR markets. The grid operator hopes the firm can make recommendations to help it address gaps in its market design and ensure the ARR/FTR market's health. (See "Concerns Develop over FTR Market," *MISO Market Subcommittee Briefs: Oct. 7, 2021*.)

LEI recommended MISO re-evaluate its basis for determining ARR entitlements and "move away from a fixed historical reference year to better track actual usage of the transmission network."

Chung said ARR megawatts tied to paths with retired generation have increased from about 1% to 3% in recent years.

"Entitlements don't track network use," LEI Managing Director Julia Frayer said, noting that entitlements should "better reflect the system today, where load and generation are."

MISO has become increasingly concerned over the congestion-hedging market's underfunding. It has said there's a growing discrepancy between awarded ARRs and the footprint's actual congestion patterns. As a result, load-serving entities hold a historically smaller share of FTRs, and the ARRs' congestion value has fallen.

The grid operator issues the financial instruments based on transmission capacity; they are used by load-serving entities and other market participants as financial hedges against congestion charges in the day-ahead market. MISO funds FTRs through day-ahead congestion costs; an ARR is the LSE's entitlement to

| © RTO Insider LLC

a share of revenue from FTR auctions because of its historical use and investment in the transmission system.

LEI noted that there have been "very few" new ARR paths allocated to LSEs and the new paths "appear to be insufficient in providing a hedge" against congestion risk. The firm said MISO should allow its LSEs to nominate more variations of paths.

The firm also recommended staff tailor their FTR products to the RTO's evolving supply mix and load patterns by offering morning, afternoon, evening and night options that could also account for weekdays or weekends. However, it acknowledged that selling FTR products by time periods would make for more complex monthly auctions.

MISO's regulated and more risk-averse LSEs have "limited participation" in the monthly FTR auctions, LEI said, so most profits go to financial traders. The firm suggested staff create an entitlement FTR product for LSEs when additional network capacity is available in the monthly auctions.

"This may help motivate LSEs to participate … without necessitating LSEs to take on any additional risk," LEI said.

The firm urged MISO to also monitor trends among pivotal suppliers and participants with large market shares competing in the FTR market and track the number of LSEs versus financial traders. It also recommended staff keep a more public tally of the amount of congestion revenue lost by transmission customers because of ARR allocation curtailments.

Finally, LEI said the grid operator should consider incentivizing more accurate reporting of transmission outages, so outages modeled in the FTR auctions match planned transmission outages and the actual outages that ultimately impact the day-ahead market.

MISO said increasing wind generation has cut down on the volume of ARRs. Wind-related ARRs tend be about one-third of those associated with retiring baseload generation.

Stakeholders agree that staff must revisit ARRs. Multiple stakeholders said state-regulated utilities cannot participate because of the market's speculative nature.

MISO's Independent Market Monitor reported that FTRs were fully funded this fall and that the grid operator collected more than $47 million in surplus. The Monitor said the surplus "indicates that some paths were significantly undersold after both the annual and monthly FTR auctions."

Monitoring staffer Carrie Milton said the quarterly surplus "would have been higher but for large shortfalls on paths that were over-allocated in MISO's ARR process."

Milton said a single transmission owner's failure to report a known transmission outage before the annual auction caused a $15 million shortfall. MISO's FTR surplus collections are used to fund shortfalls, so that the costs of over-allocations are subsidized by all other transmission customers.

Monitor David Patton is asking MISO crack down on transmission owners not reporting outages to MISO before AARs/FTRs are issued.

Patton said in a footprint that racks up billions of dollars in congestion, an unreported outage can have "tens of millions of dollars" in ramifications when a TO sells property rights to its lines but doesn't disclose planned outages. ■

NYISO Business Issues Committee Briefs

CRIS Revisions Advance

The NYISO Business Issues Committee on Wednesday approved proposed tariff *revisions* to rules for capacity resource interconnection service (CRIS) expiration and transferring.

The revisions are intended to facilitate increased capacity deliverability headroom while lowering the cost of new entry in the capacity market.

The ISO is looking to complete relevant software upgrades by the fourth quarter. The changes would go into effect immediately after FERC approval. (See *NYISO Finalizes CRIS Tariff Revisions*.)

Although the proposal passed with 90.36% support, there were multiple abstentions. The Long Island Power Authority (LIPA), which called for a roll call vote, was the only stakeholder against it.

David Clarke, director of wholesale market policy at LIPA, said the utility "recognizes the value of many of the CRIS transfer and expiration proposals" but has concerns regarding the "three-year CRIS expiration rule as applied to external unforced capacity deliverability rights."

"Recent experience has shown that the process to procure external capacity does not align well with the New York capacity market and creates significant challenges to acquire available resources from external control areas with three-year forward commitments for participation in the short-term NYISO capacity market," Clarke said.

The proposal "places external controllable lines at a competitive disadvantage with internal resource supplies" and "does not address important issues with respect to maintaining CRIS for inter-ISO capacity sales," he said.

The revisions go before the Management Committee this Wednesday, and the ISO anticipates obtaining Board of Directors approval and filing with FERC before the end of the first quarter.

Winter Storm Price Impacts

Rana Mukerji, NYISO senior vice president of market structure, *presented* the committee with the ISO's monthly market performance report for December, highlighting how the winter storm significantly impacted energy prices across New York. (See *FERC, NERC Set Probe on Xmas Storm Blackouts*.)

The storm drove up natural gas prices, causing the locational-based marginal pricing to reach an average of $110.17/MWh, more than double the $52.47/MWh seen in November 2022 and nearly 130% higher than the $47.99/MWh from December 2021.

When asked about how the storm can be viewed historically, Mukerji said it was "certainly exceptional" and that the closet comparison is the 2013/14 polar vortex.

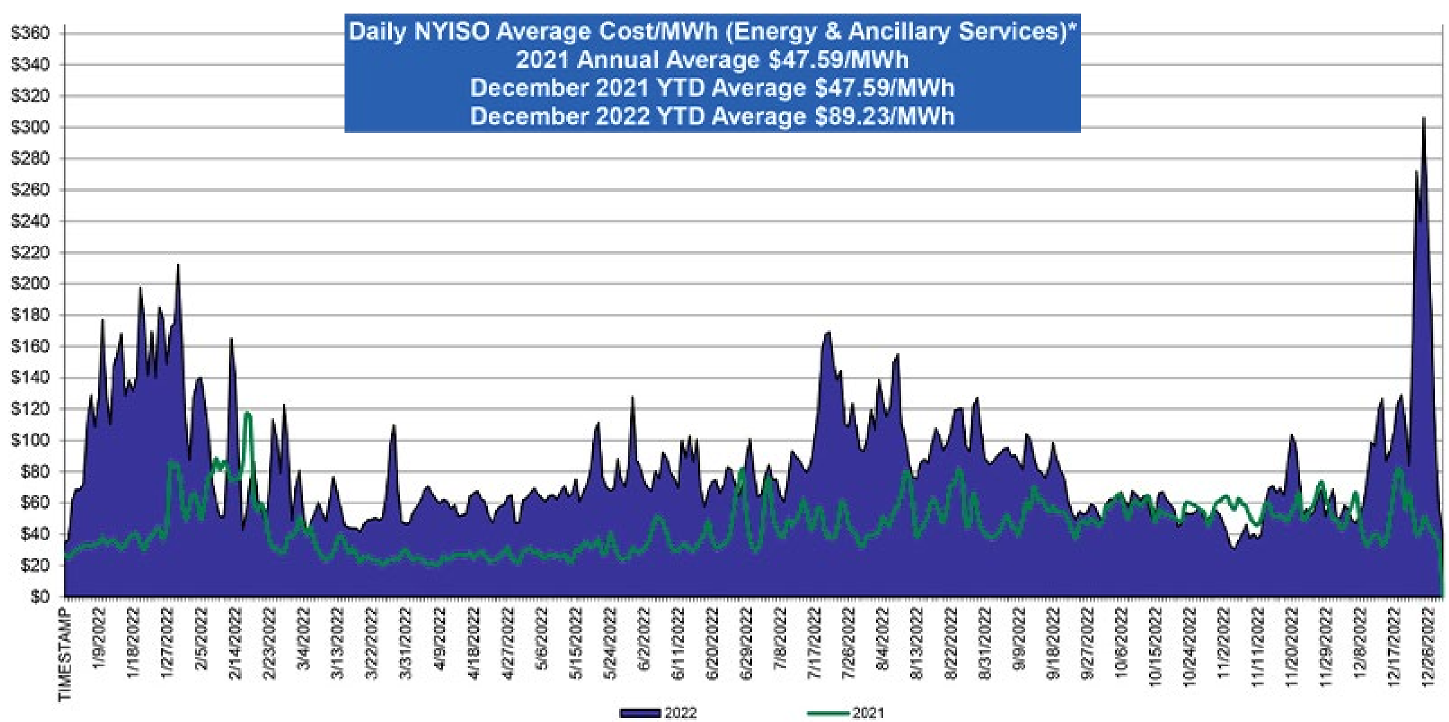
Bouchez Named Consumer Liaison

NYISO announced that Nicole Bouchez, principal economist of market design, would be taking over the duties of consumer impact and interest liaison, replacing Tariq Niazi, who retired at the end of last year.

Bouchez has been with NYISO since 2003 and principal economist since 2011. She was also co-chair of the Integrating Public Policy Task Force, a joint group with the New York Department of Public Service that solicited stakeholder proposals on carbon pricing, in 2017-2018.

Bouchez said consumer interest is an exciting area and enables her to continue being involved in market design discussions. ■

— John Norris



Daily NYISO Average Cost/MWh (Energy & Ancillary Services) | *NYISO*

FERC Approves NYPA Cost Recovery for Smart Path Project

By John Norris

FERC on Thursday approved the New York Power Authority's transmission rates for the *Smart Path Connect* transmission project (SPCP) after the utility showed it received state approval for the project (*EL22-15-001, ER22-1014-002*).

The commission had approved NYPA's request for the abandoned plant incentive (API) in March 2022 — as well as a 50-basis-point return on equity adder and performance-based ROE incentive later in July — but on the condition that the New York Public Service Commission grant the project a certificate of environmental compatibility and need, and approve its environmental management and construction plan (EMCP). These approvals, FERC said, would show the project addresses reliability and congestion, required for the incentives under Federal Power Action 219.

The PSC granted the project, which aims to rebuild about 100 miles of old 230-kV transmission lines in northern New York as 345 kV, the certificate in August 2022 (*21-T-0340*). But NYPA told FERC that the New York commission has only approved an EMCP for part of the project.

"NYPA explains that, because of the expedited nature of the project, and in consultation with staff from the New York Department of Public Service, the EMCP approval process for NYPA's part of the project was broken into two segments to enable a timely start to construction of the project," FERC said in its order. NYPA expects approval of the second segment this February.

NYPA, however, argued that "the EMCP has no bearing on whether the project reduces congestion and saves consumers money," as those issues were addressed in the certificate. Furthermore, the remaining EMCP approval only relates to how the project will be physically constructed, versus whether the SPCP is needed.

FERC agreed with NYPA. "Upon review of the EMCP approval included with [a] supplemental filing, we agree with NYPA that the EMCP approvals are related to physical construction and do not address reliability or congestion criteria," it said.

Construction recently *began* on the project, with an anticipated in-service date of fall 2025, though significant work remains.

NYPA estimates the total capital cost will be $1.1 billion, with the utility responsible for $641.3 million. The PSC found that the project will produce congestion cost savings of approximately $450 million, as it "represents an upgrade to the transmission backbone system of New York that will improve reliability throughout the state." ■

Ceremonial groundbreaking for Smart Path Connect in Massena, N.Y. | *National Grid*

Financial Concerns Continue for Major Northeast OSW Projects

Ørsted Expects $365M Hit on Sunrise Wind; Avangrid Appeals to Exit Commonwealth

By John Cropley

Two major offshore wind power developers are warning again of economic problems with projects off the New York and New England coasts.

Ørsted on Thursday *notified* investors that there would be a cost impairment of 2.5 billion kroner (roughly $365 million U.S.) on the 924-MW Sunrise Wind project in New York, its 50/50 venture with Eversource Energy, because of rising interest rates, higher capital costs and inflation.

And Avangrid, which has said repeatedly that its 1,232-MW Commonwealth Wind project will be impossible to finance as negotiated, filed an *appeal* Thursday with the Massachusetts Department of Public Utilities, seeking once again to exit the power purchase agreements.

Inflation is hitting many areas of the renewable energy industry, particularly the offshore wind sector, which is forming nearly from scratch in the U.S. (See related story, *Inflation Throwing a Wrench into Renewable Development*.)

During a conference call Friday with Ørsted CEO Mads Nipper, financial analysts drilled in the company's offshore projects broadly and Sunrise specifically.

Nipper said Ørsted is negotiating contracts for Sunrise in a very expensive environment, particularly for transportation and installation costs. Barring further increases in interest rates, he said, Ørsted does not expect 2023 impairments on other projects in its offshore portfolio, which were negotiated in less expensive environments.

An installation vessel is being built for Sunrise, Nipper added, and while it is a bit behind schedule, it should be ready in time to work next year.

Like Avangrid, Ørsted says it remains committed to its Northeastern offshore wind projects.

Financial concerns continue for offshore wind farms planned off the coasts of New York and Massachusetts. | *Shutterstock*

It previously acquired the first commercial OSW project in the U.S., Block Island Wind in Rhode Island, and is a partner in the construction of the second, South Fork Wind in New York.

On Wednesday, a day before it quantified the financial obstacles facing Sunrise, Ørsted *announced* it had acquired Public Service Enterprise Group's 25% share of Ocean Wind 1, giving it 100% ownership of the 1,100-MW project off the New Jersey coast. Nipper told analysts Friday that PSEG's exit did not indicate the project was in trouble; rather, it was a strategic move to optimize tax credits.

The company said preliminary unaudited results show 2022 earnings from its worldwide offshore business down 9.5% from 2021, primarily because of delays to three projects and impacts from hedging. But it expects significantly higher offshore earnings in 2023.

Ørsted's stock price dropped 8.7% in trading Friday.

The Commonwealth project has been unraveling for the last few months, with Avangrid saying it has negative net value as negotiated. The company has said it remains committed to the concept and would like to submit a viable bid on the project in Massachusetts' next offshore wind solicitation.

The Massachusetts DPU has rejected Avangrid's requests, first to pause its review of the power purchase agreements with three electric distribution companies, and then to dismiss the PPAs altogether. The companies meanwhile refused to negotiate any changes. (See *Mass. DPU Orders Commonwealth Wind Project to Continue*.)

In its appeal Thursday, Avangrid said the DPU's orders are based on errors in law, unsupported by evidence, and arbitrary, capricious and an abuse of discretion.

Developers of another proposed Massachusetts wind farm — Mayflower Wind, phase 1 of which would deliver 405 MW — have cited the same financial pressures as Commonwealth but have not yet attempted to back out.

Mayflower, which previously was granted limited participant status in the Commonwealth proceeding because the two projects are interrelated, *requested* full participant status Thursday because of Avangrid's latest motion. ■

NYISO News

NYISO Outlines Timelines for 2023 Projects

By John Norris

NYISO last week *presented* the Installed Capacity/Market Issues Working Group (ICAP/MIWG) with the anticipated schedules for its Installed Capacity market, energy market and new resource integration projects for this year.

The ISO plans to return to stakeholders each quarter to share status updates on each project. (See "Four Projects in 2023 Budget from Consumer Impacts Analysis," *NYISO Details 2023 Budget & Compensation Updates*.)

Maddy Mohrman, NYISO capacity market design specialist, overviewed the capacity market design projects, including their anticipated first-quarter schedules and deliverables for this year.

The first project is modeling improvements for capacity accreditation, necessitated after NYISO discovered limitations within its resource adequacy analysis software, GE MARS.

NYISO will work with stakeholders and the New York State Reliability Council to improve the software by the fourth quarter. The updates should enable more accurate calculations for resource adequacy requirements, capacity accreditation factors and capacity accreditation resource classes.

The ISO will also work to improve the methodology for its LCR Optimizer software, which establishes the locational minimum installed capacity requirements (LCRs). It will spend the first quarter investigating the need for and developing any necessary enhancements to the software to improve the stability and transparency of LCRs, with an anticipated completion in the third quarter.

2023 Capacity Market Design Projects	Q1	2023 Deliverable
Modeling Improvements for Capacity Accreditation	CD	Q4 Functional Requirements
LCR Optimizer Enhancements	CD	Q3 Market Design Complete
Demand Curve Reset	CD	Q3 Study Defined

2023 Capacity Market Ongoing and Implementation Projects	Q1	2023 Deliverable
Improving Capacity Accreditation	FR	Q4 Deployment
CRIS Expiration Evaluation	MDC	Q4 Functional Requirements

Key			
CD	Continued Discussions	MDC	Market Design Complete
ID	Issue Discovery	FR	Functional Requirements
SD	Study Defined	SD	Software Design Specification
SC	Study Complete	DC	Development Complete
CP	Market Design Concept Proposed	DEP	Deployment

2023 capacity market project overview | *NYISO*

Another project relates to the 2025-2029 demand curve reset (DCR), a comprehensive review to determine the necessary assumptions for developing the ICAP demand curve. The project will be ongoing until 2025, but NYISO plans to post the DCR schedule in the first quarter of this year, select an independent consultant to conduct the study during the second quarter, and spend the rest of the year defining the inputs and methodology for the study.

Other software updates are needed to implement NYISO's new capacity accreditation procedures and capacity resource interconnection service (CRIS) expiration rules.

NYISO has begun making the updates for capacity accreditation but anticipates they won't be deployed until the fourth quarter and only become operational in 2024. It expects the upgrades for CRIS to be finished by the fourth quarter. (See *NYISO Capacity Accreditation Implementation Worries Stakeholders* and *NYISO Finalizes CRIS Tariff Revisions*.)

Energy Market Projects

Amanda Myott, NYISO energy market design specialist, detailed the energy market projects, including a project to rethink how to balance system needs as more intermittent renewables, energy storage resources (ESRs) and distributed energy resources come online.

The ISO anticipates proposing a market design concept by the end of the year based on previous studies of grid characteristics, resource attributes and new market products necessary to reliably maintain system balance.

Another project includes developing potential software and market rules that would enable NYISO to dynamically schedule reserves or procurements, which would better align market outcomes with system conditions by determining reserve requirements within a given region (See *Study: NYISO Dynamic Reserves Could Lower Congestion, Costs*.)

NYISO will spend the first quarter overviewing the project plan, looking through scheduling and pricing examples in the day-ahead-market and examining if updates are required to the posting of reserve requirements. It anticipates completing the market design by the third quarter.

Another projects centers on creating more transparency around emissions data, which the ISO believes will help end users and other market participants optimize their electricity usage. It expects to finish the necessary functional requirements and start publishing emissions rate data by the end of the year.

2023 Energy Market Design Projects	Q1	2023 Deliverable
Balancing Intermittency (SOM)	CD	Q4 Market Design Concept Proposed
Dynamic Reserves (SOM)	CD	Q3 Market Design Complete
Emissions Transparency	CP	Q4 Functional Requirements
Evolving Financial Transaction Capabilities- Bilateral Transactions	CP	Q4 Software Design Specification
Enhancing Fuel and Energy Security	CD	Q4 Study Complete
Long Mountain PAR Operating Protocol with ISO-NE	CD	Q4 Market Design Complete

2023 Energy Market Ongoing and Implementation Projects	Q1	2023 Deliverable
Constraint Specific Transmission Shortage Pricing	SD	Q4 Deployment

Key			
CD	Continued Discussions	MDC	Market Design Complete
ID	Issue Discovery	FR	Functional Requirements
SD	Study Defined	SD	Software Design Specification
SC	Study Complete	DC	Development Complete
CP	Market Design Concept Proposed	DEP	Deployment

2023 energy market project overview | *NYISO*

Mark Younger, president of Hudson Ener-

NYISO News

gy Economics, asked if this effort would be impacted by the cap-and-invest program proposed by New York Gov. Kathy Hochul, but NYISO said the project was an independent initiative. (See *Hochul Highlights Cap and Invest in State of the State Address*.)

William Acker, executive direct of the New York Battery and Energy Storage Technology Consortium, said that there's a strong need for the project because it will help New York City buildings comply with Local Law 97 by better understanding how they can shift their energy consumption based on their emissions profile. (See *NYC Proposes Rules to Implement Building Emissions Law*.)

NYISO's energy market team will also work to enhance the software for internal bilateral transactions, which currently does not enable ESRs to be a sink.

Stakeholders had indicated this project as a priority as the demand for ESRs to use bilateral transactions to contract output from specific resources has increased. The ISO expects software design specifications to be completed by the end of the year.

NYISO will also conduct a fuel and energy security study, which stems from a recognition that New York's fuel supply mix is rapidly evolving and extreme weather events have become increasingly disruptive. This study is expected to be completed by the fourth quarter and will be a refresh from a similar 2019 security *study*, which examined future reliability standards, resource mix and load patterns, and resource requirements.

Chris Wentlent, of the Municipal Electric Utilities Association of New York State, asked if the study would be New York-specific or also investigate neighboring grid operators, including in Canada.

Myott replied that NYISO is considering including their neighbors in the study.

The last planned energy market project focuses on creating an operating protocol for the Long Mountain phase angle regulator (PAR) installation, a planned 345-kV intertie between NYISO and ISO-NE. The plan is to complete and vote on a joint operating agreement by the end of this year, though if discussions with ISO-NE extend beyond the third quarter, the project could be delayed.

An ongoing project relates to updating software to implement constraint-specific transmission shortage pricing, which would help NYISO to alleviate short-term constraints by dispatching suppliers more efficiently. The ISO plans to deploy these updates in October,

2023 NRI Market Design Projects	Q1	2023 Deliverable
FERC Order 2222 Compliance	CD	Q4 Market Design Concept Proposed
Engaging the Demand Side	CD	Q4 Issue Discovery
Storage as Transmission	CD	Q4 Issue Discovery

2023 NRI Ongoing and Implementation Projects	Q1	2023 Deliverable
Internal Controllable Lines	CD	Q4 Market Design Complete

Key			
CD	Continued Discussions	MDC	Market Design Complete
ID	Issue Discovery	FR	Functional Requirements
SD	Study Defined	SD	Software Design Specification
SC	Study Complete	DC	Development Complete
CP	Market Design Concept Proposed	DEP	Deployment

2023 new resource integration project overview | *NYISO*

after the relevant DER updates are finalized, and will file the previously approved project modifications with FERC in the first half of the year.

New Resource Integration Projects

Finally, Harris Eisenhardt, NYISO market design specialist, presented an overview for the new resource integration projects.

While waiting for a final ruling from FERC on its Order 2222 compliance, the ISO has worked in other ways to integrate DERs. (See *NYISO Justifies Unpopular 10-kW DER Aggregation Min. Requirement*.)

By the end of this year, NYISO anticipates delivering a market design concept that will enable its DER participation model to be fully compliant with FERC Order 2222 requirements by incorporating any additional market features that were not included in the deployment scope.

Howard Fromer, who represents the Bayonne Energy Center, sought confirmation that FERC approved NYISO's request to extend the deadline for DER deployment until 2026, which Eisenhardt confirmed, saying the ISO would spend the next three years scoping out the DER software, getting the market design finished and building out the deployment plan.

Another project that concerns the demand side to identify new ways that demand response and DER programs can be improved to increase consumer engagement in NYISO's markets. The ISO believes that improving demand-side programs will enable consumers to assume greater control of their energy use and push New York toward zero emissions by better balancing increasing penetration of intermittent generation.

The ISO anticipates presenting a final report, which summarizes both external and internal stakeholder feedback and identifies gaps in existing programs, in the fourth quarter.

James W. Brew, principal at Stone Mattheis Xenopoulos & Brew, and Kevin Lang, partner at Couch White, both emphasized the importance of NYISO soliciting feedback from experienced individuals and talking directly with end-use consumers.

Finally, Eisenhardt discussed the project to assess whether storage resources can be considered transmission assets.

NYISO expects to share its findings during the fourth quarter, spending the earlier part of the year reviewing how other grid operators treat storage resources and discussing operating rules for market participation. ■

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NYISO TPAS Briefs

Inverter-based Resource Work Plan

Roger Clayton of the New York State Reliability Council (NYSRC) informed stakeholders at Thursday's Transmission Planning Advisory Subcommittee (TPAS) that the council is developing interconnection reliability rules for inverter-based resources (IBRs).

Clayton said there is an "urgency" for the project because there is no standard interconnection process for IBRs, save for *IEEE 2800*, which, although approved last February, has yet to be adopted by any authorized agency responsible for regulating interconnection requirements.

Additionally, NERC has only released guidance *documents*. Although helpful, they "are not standards and only recommendations," Clayton said.

Therefore, NYSRC is "taking action now" to get ahead of the anticipated influx of IBR projects in NYISO's interconnection queue.

The IBR standards will be based around IEEE 2800 but tailored to the New York market. NYSRC is looking to get them in place as soon as possible, with the goal of having them be applicable to the Class Year 2023 slate of resources.

Clayton admitted this will be challenge, because NYSRC lacks relevant modeling and validation expertise; IBRs are new technologies that NYSRC has not extensively handled; and the timing will be tight, as CY23 starts Feb. 13.

NYSRC, however, has been working on the *project* since last year, and Clayton was confident that even if it misses its self-imposed deadline, it would still work to get the rules in place.

Clayton emphasized the project's importance, calling attention to ERCOT and CASIO, which have both seen upticks in IBR interconnections but have experienced difficulties.

Gillian Coats, director of interconnection at Boralex, asked whether NYSRC was "putting the cart before horse" by trying to implement these new rules without a clear procedure in place.

"In a way we are," said Clayton, "but if we wait, then there will be a bunch of projects that are interconnected without an objective standard, so there is definitely a tradeoff."

NYISO headquarters in Rensselaer, N.Y. | *NYISO*

Clayton, who is also chair of the council's Reliability Rules Subcommittee, told stakeholders that NYSRC will host a *meeting* in two weeks to discuss the IBR draft rules and solicit additional stakeholder feedback.

Queue Reform

Thinh Nguyen, senior manager of interconnection projects, told stakeholders that NYISO continues to work on the interconnection queue to make it more responsive, transparent and expeditious.

Nguyen said that the queue has expanded from 120 projects in 2018 to 475, which has placed a tremendous workload on NYISO staff.

After initial stakeholder consultations, NYISO came away with several modifications. These included improving the interconnection portal; creating and hiring a dedicated stakeholder interaction liaison who can provide inquiry service to allow engineers to focus on technical issues; adding more project managers to handle collaborative utility processes; and eliminating certain evaluations.

These have not required tariff changes, and several have already been implemented. But NYISO anticipates that further tariff-related enhancements will be required. (See *NYISO Investigating Tariff Changes to Improve Interconnection Processes*.)

Nguyen said the ISO will solicit further stakeholder feedback for the next two months, requesting comments be sent to *stakeholder_services_IPsupport@nyiso.com*. It will then spend spring addressing feedback and refining tariff proposals before seeking approval votes in the third quarter to ensure changes are filed with FERC before the end of the year.

Class Year Updates

NYISO Manager of Facility Studies Wenjin Yan updated stakeholders about the current status of Class Year projects.

CY21 was completed Jan. 11, and NYISO sent a notice to developers about the CY23 start date, noting that developers had until Jan. 20 to inform the ISO if they wanted to enter CY23. (See *NYISO Completes Class Year 2021 Projects*.)

NYISO also informed stakeholders that the next expedited deliverability study would start Feb. 23. ■

— John Norris

NYISO Operating Committee Briefs

By John Norris

December Operations Report

NYISO updated the Operating Committee on the December snowstorm's impact on grid operations, highlighting a particularly sharp shortfall in scheduled generation on Christmas Eve.

ISO Vice President of Operations Aaron Markham said that at one point that day 2,600 MW of generation scheduled in the day-ahead market failed to show up in real-time. (See *FERC, NERC Set Probe on Xmas Storm Blackouts*.)

He also said that Dec. 24 saw the winter season's peak load to date, reaching 22,004 MW.

Regionally, conditions were tight, particularly in PJM, which experienced significant outages, resulting in NYISO having to facilitate emergency energy purchases and deliveries from both ISO-NE and IESO in Canada to PJM.

| *NYPA*

NYISO staff plan to return to the OC in March with a comprehensive report on Winter Storm Elliot's full impact on the New York Control Area, focusing on what caused outages, where production was reduced and what corrective actions need to be taken.

Howard Fromer, who represents the Bayonne Energy Center, asked whether the storm caused load to significantly deviate from ISO forecasts.

Markham responded that about 500 MW of committed resources may have underperformed in real-time but that was not significantly impactful.

ICAP Demand Curve Updates

Stakeholders approved final results for locational minimum installed capacity requirements (LCRs), net cost of new entry curves and transmission security limit (TSL) floors for the 2023/24 capability year. (See 'Final LCR Results,' *NYISO Stakeholders Still Concerned About DER Participation Model*.)

Yvonne Huang, NYISO resource adequacy manager, said updates to the modeling and methodology from last year included adopting GE's dynamic energy limited resource functionality, maintaining 350 MW of operating reserves during load-shedding events, adopting new load shapes based on data from more recent years and considering generator outages in the TSL calculations to better align with methodology used in ISO planning studies. ■

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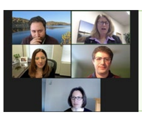

Many Questions on NY Energy Transition Don't Have Answers Yet NetZero Insider

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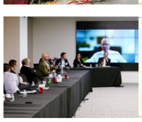

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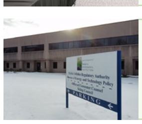

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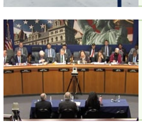

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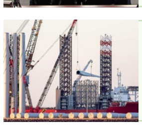

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PJM News

Generators Oppose PJM Filing to Change Capacity Auction Parameters

By Devin Leith-Yessian

Stu Bresler, PJM | *© RTO Insider LLC*

Generation owners are attacking PJM's filing asking FERC to approve a change to the parameters of the RTO's 2024/25 capacity auction, calling it a tariff violation and an attempt to intervene on behalf of buyers.

But utilities and state advocates argue that the potential impact of the auction's results on ratepayers justifies the action.

In two filings last month, PJM laid out how a mismatch between the resources used to calculate the reliability requirement for the DPL South (DPL-S) locational deliverability area (LDA) — centered on the Delmarva Peninsula — and those that actually participated in the auction led to a fourfold increase in clearing prices compared with the previous year's auction (*EL23-19, ER23-729*).

Describing the outcome as an artificial inflation in prices, the filings asked the commission to allow PJM to revise the reliability requirement to remove those generators that did not enter the auction as an additional step in the optimization algorithm run after bids have closed. (See *PJM Decides Against Posting Indicative Capacity Auction Results*.)

The core argument of the generators' protests is that PJM's tariff requires it to close the auction and post the results as soon as possible and that the RTO lacks the authority to hold it open while making a filing with FERC.

Former FERC Chair Joseph Kelliher submitted an affidavit in support of the PJM Power Providers (P3) *protest* to PJM's filing, saying that granting the RTO's request would violate the filed rate doctrine, which prohibits the charging of rates different from those filed with FERC, and the rule against retroactive ratemaking.

In rebutting PJM's argument that changing the auction parameters would not violate the rules because the auction has not been completed, Kelliher compared the auction results to Schrodinger's Cat. He noted that the RTO has stated that the results are preliminary and incomplete, but relies on the figures to estimate the impact to clearing prices in DPL-S.

"[T]he auction process appears to be final, except for the ministerial step of posting the auction results that PJM apparently has in hand but refuses to formally post — are the auction results final or preliminary?" he wrote.

Kelliher also argued that granting PJM's requests would be bad policy, undermining confidence in capacity auctions and the commission.

"The commission has consistently recognized the importance of assuring market certainty and maintaining market integrity, even to the extent of opposing the re-running [of] RTO auctions to provide refunds as remedies in FPA Section 206 complaint proceedings and in response to court remands, where [the] commission has discretion to order re-running of markets, on the grounds that doing so would 'undermine confidence in markets,'" he said.

NRG Argues Price Jump was Predictable Months Before Auction

In its *protest*, NRG Energy said it had relied on the market information and price estimates based on them to make "irreversible commercial decisions."

"In its determination to retroactively revise the auction results to avoid politically unpalatable results dictated by the rules in effect when the auction was conducted, PJM blithely ignores the substantial and actual reliance interests of the NRG Companies and other market participants and proposes to change the rules after-the-fact," the company wrote.

It also argued that PJM should have been aware of the likelihood that the reliability requirement would lead to elevated prices in DPL-S, as the company had previously reached out to PJM to inquire about the 12% increase for the LDA. The RTO responded that historical winter forced outages and expected increase in solar resources increased the risk of loss of load in the winter, leading to the higher reliability requirement.

Based on those parameters, the company estimated that the LDA would clear at around the cap of $426.17 MW/day and instructed traders to rely on PJM's parameters after receiving its response, leading the company to reject capacity purchase offers on the grounds that it expected higher prices.

EPSA Worries About Reliability Impacts

The Electric Power Supply Association (EPSA) noted that the reliability requirement for LDAs looks at existing resources and projected resources expected to be in service, rather than at resources with Reliability Pricing Model (RPM) commitments. For that reason, EPSA contended, revising the reliability requirement to exclude resources not offered into the Base Residual Auction (BRA) would create a "false equivalence between the reliability needs of an LDA and the supply and demand in the LDA in an RPM auction."

PJM News

Drawing on information in an affidavit by Paul Sotkiewicz, president of E-Cubed Policy Associates, EPSA argued the effect would be dramatic differences in clearing prices depending on whether resources participated in auctions, regardless of whether those resources are actually available during the delivery year.

"The prices PJM would determine might not be high enough to attract future new resources to take on an RPM commitment especially knowing PJM is willing to put its finger on the scale to reduce prices even in the face of reliability needs with its proposal," Sotkiewicz wrote.

AMP, Public Citizen Argue PJM Doesn't Go Far Enough

American Municipal Power *argued* that FERC approval of PJM's filing is necessary to avoid ratepayers paying a "Locational Reliability Charge that is unjust, unreasonable and unduly discriminatory." The nonprofit, whose members include the Delaware Municipal Electric Corporation, said the RTO's solution could leave future BRAs open to similar issues and called on FERC to establish a technical conference to explore long-term solutions.

In particular, AMP argued that the small size of many LDAs within PJM can cause price volatility through changes in load forecasts, uneven growth in resource development and generators not participating in auctions.

"It is therefore critical that LDAs in PJM be sized large enough that the failure of one resource or a small set of resources to participate in RPM auctions, or the inability to site new generation, does not drastically increase the auction clearing price," AMP wrote.

The nonprofit power supplier also questioned PJM's proposal to trigger the process of recalculating the reliability requirement to remove resources not participating in the BRA when the parameter increases more than 1% over the previous year. It noted that a 400% increase in clearing prices could be attributed to the 12% increase in the requirement. A 1% increase in the threshold would still correspond with a 33% rise in prices should the impact prove to be linear, AMP said.

Public Citizen *argued* that FERC should approve PJM's requests, establish a refund date and investigate whether market participants engaged in intentional capacity withholding. It also wrote that future BRA results should be filed as standalone Section 205 rate filings to allow for public inspection of rates with the ability for comments and protests to be submitted before rates go into effect.

"Setting the matter for hearing and subjecting the capacity auction to refunds is the statutorily appropriate path for the commission to pursue, rather than PJM's proposed 'do over' which does not appear to be permitted by its tariff. Subjecting the auction results to a hearing with refund authority will protect consumers and ensure accountability for any generators that engaged in capacity withholding," the organization wrote.

Delmarva Zone Parties, ODEC Support PJM Approach

In its *comments* supporting PJM's filings, Old Dominion Electric Cooperative said that actions being proposed are justified given the "artificially increased and unreasonable clearing price" that ratepayers would pay without any added benefits from the higher costs.

"The fact that prices are being increased and LSEs (and, thereby, consumers) will pay for an inappropriately calculated Reliability Requirement is in and of itself sufficient basis for the commission to take action to prevent the imposition of unjust and unreasonable capacity prices for the DPL-S LDA. When there are no discernable benefits from increased prices, the rates cannot possibly satisfy the requirement that customers receive benefits that are at least roughly commensurate with costs," the cooperative wrote.

Several Delaware, Maryland and Virginia public organizations also *supported* PJM's filings and said whatever solution FERC may approve, priority should be given to ensure that further delays in the BRA are avoided. Jointly filed by the Delmarva Zone Parties, the comment was signed by the Delaware Public Service Commission, Delaware Division of the Public Advocate, the Delaware Municipal Electric Corporation, Maryland Public Service Commission and the Virginia State Corporation Commission.

"Avoiding further delays in the BRA timeline is particularly critical as PJM stakeholders seek to reestablish the three-year forward procurement of capacity resources that has already been delayed by various proceedings before the Commission. Instead, in an effort to minimize disruption to the BRA process, PJM proposes to prospectively include a new element to its optimization algorithm that would allow it to reflect more accurately supply and demand levels while evaluating Sell Offers before determining capacity awards," the parties wrote. ■

PJM MRC/MC Preview

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

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

The committee will be asked to endorse:

B. proposed revisions to Manual 2: Transmission Service Request, to clarify changes made to the internal network integration transmission service process, as well as administrative cleanup. (See "Streamlining Internal NITS Process Under Consideration," *PJM MRC/MC Briefs: Sept. 21, 2022*.)

C. proposed revisions to Manual 14A: New Services Request Process and Manual 14B: PJM Regional Transmission Planning Process, addressing the generator deliverability test. (See Stakeholders Endorse Changes to Generator Deliverability Test," *PJM PC/TEAC Briefs: Jan. 10, 2023*.)

D. proposed revisions to Manual 28: Operating Agreement Accounting, addressing conforming clarifications and corrections to support the implementation of reserve price formation expanding on the revisions endorsed by the MRC in September 2022.

E. proposed revisions to Manual 38: Operations Planning, resulting from its periodic review.

F. proposed revisions to the Regional Transmission and Energy Scheduling Practices document, to conform to the new North American Energy Standards Board's Business Practice Standards version 3.3.

Endorsements (9:10-10:30)

1. CIRs for ELCC Resources (9:10-9:35)

PJM's Brian Chmielewski will review a proposal addressing capacity interconnection rights for effective load-carrying capability resources, endorsed by the Planning Committee during its Jan. 10 meeting. (See *PJM Planning Committee Endorses Capacity Accreditation for Renewables*.) The committee will be asked to endorse a solution and corresponding manual, tariff and Reliability Assurance Agreement revisions.

Issue Tracking: *Capacity Interconnection Rights (CIR) for ELCC Resources*

2. Emerging Technology Forum Charter (9:35-9:50)

PJM's Scott Baker will review proposed revisions to the Emerging Technology Forum charter. The committee will be asked to endorse the charter revisions.

3. Hybrid Resources Phase II (9:50-10:10)

PJM's Danielle Croop will review the package detailing the Hybrid Resources Phase II solutions. (See "MIC Endorses Proposal on Hybrid Resources," *PJM MIC Briefs: Nov. 2, 2022*.) The committee will be asked to endorse a proposed solution and corresponding tariff and Operating Agreement revisions.

Issue Tracking: *Day-ahead Zonal Load Bus Distribution Factors*

3. Day-ahead Zonal Load Bus Distribution Factors (10:10-10:30)

PJM's Amanda Martin will review a proposed solution package to revise PJM's zonal load bus distribution factors methodology to look at all hours of a given day. (See "Manual Revisions for Day-ahead Zonal Load Bus Distribution Factors Endorsed," *PJM MIC Briefs: Dec. 7, 2022*.) The committee will be asked to endorse revisions to Manual 11: Energy and Ancillary Services Market Operations, Manual 28: Operating Agreement Accounting and tariff section 31.7.

Members Committee

Consent Agenda (1:20-1:25)

The committee will be asked to:

B. approve proposed OA revisions addressing the treatment of market suspensions. (See "Market Suspension," *PJM Market Implementation Committee Briefs: June 8, 2022*.)

Issue Tracking: *Rules Related to Market Suspension*

C. endorse proposed tariff and OA revisions addressing the alignment of PJM's authority in event of a default. (See "1st Read on Proposal to Allow Flexibility for Market Participation During Defaults," *PJM MRC Briefs: Nov. 16, 2022*.)

Issue Tracking: *Market Participant Default Flexibility*

D. endorse proposed clarifying tariff and OA revisions as endorsed by the Governing Documents Enhancements and Clarifications Subcommittee (GDECS).

Endorsements (1:25-2:00)

1. Manual 34 Revisions (1:25-1:40)

Adrien Ford, of Old Dominion Electric Cooperative, will move — and Jim Benchek of Monongahela Power will second — a main motion for proposed revisions to Manual 34: PJM Stakeholder Process, addressing motions for new issues at the Members Committee. The new language would allow for issues that are best addressed by the MC to be brought as a problem statement and issue charge directly before the committee. The committee will be asked to approve the proposed Manual 34 revisions.

2. CIRs for ELCC Resources (1:40-2:00)

See MRC item 1 above. Following potential same-day endorsement at the MRC, the MC will be asked to endorse the corresponding tariff and RAA revisions.

Issue Tracking: *Capacity Interconnection Rights (CIR) for ELCC Resources* ■

— Devin Leith-Yessian

Mid-Atlantic news from our other channels

Pa. County Agencies Unite for 15-MW Solar Buy

NetZero Insider

New Md. Governor May Bring New Workforce Tactics to Climate Efforts

NetZero Insider

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

SPP News

SPP MOPC Briefs

SPP, MISO Applying for DOE Funds to Help with JTIQ Portfolio

OKLAHOMA CITY — SPP told its members last week that it will apply for grants from the U.S. Department of Energy to help fund transmission projects recently identified with MISO along their seam that could unclog their generation interconnection queues.

David Kelley, SPP | © *RTO Insider LLC*

David Kelley, the RTO's newly minted vice president of engineering, said DOE's $10.5 billion *Grid Resilience and Innovation Partnerships (GRIP)* program aligns neatly with SPP's Joint Targeted Interconnection Queue (JTIQ) study with MISO.

GRIP, authorized under the Infrastructure Investment and Jobs Act, is designed to accelerate the deployment of "transformative" projects that improve the grid's flexibility and resilience against the growing threats of extreme weather and climate change. It includes a focus on interregional projects, investments that accelerate the interconnection of clean energy generation, and using distribution assets to provide backup power and reduce transmission requirements. (See *DOE Opens Applications for $6B in Grid Funding*.)

The JTIQ study resulted in five projects on the MISO-SPP seam that should help reduce congestion and allow additional resources, primarily wind farms, to interconnect with the RTOs' systems. Their staffs have *proposed a cost allocation* that assigns most of the portfolio's $1.06 billion in costs to generation. (See *MISO, SPP Propose 90-10 Cost Split for JTIQ Projects*.)

"We have still yet to find the magic unicorn of developing transmission along the seams," Kelley said. "When we looked at [the GRIP] program and what it was intended to do, it almost reads as if it was written for something like what JTIQ was trying to do. It was kind of a no-brainer for us to seek to receive some of this money on behalf of our members."

Kelley said an initial concept paper has already been filed with the program's administrators, meeting a Jan. 13 deadline. DOE will review the applications to determine whether they are worthy of full applications, providing that feedback to applicants. Final applications will be due May 19.

SPP's Casey Cathey addresses January's MOPC meeting in Oklahoma City. | © *RTO Insider LLC*

Under DOE's *Grid Innovation Program*, applications must come from a state or a group of states, regulatory commissions or tribal or local governments. That has led SPP and MISO to collaborate with the Minnesota Department of Commerce and the Great Plains Institute (GPI) on the effort. The state of Minnesota, as a potential eligible recipient of the funds, made the filing. The institute is coordinating the effort by holding discussions with utilities that will build the projects and those utilities and states that will be affected.

"Our job has been to facilitate all potentially affected folks to kind of vet the DOE requirements," Matt Prorok, GPI's senior policy manager, told *RTO Insider*. "How might those be fulfilled? Are [the JTIQ] projects a good fit for this funding bucket?"

Kelley pointed out that the GRIP program is a partnership involving federal and private dollars.

"We feel pretty good about it. We've talked to DOE a number of times, and they were very interested in what we're doing here," Kelley said. "We are being encouraged by what we're hearing. But again, because this is a partnership, we do think it's important that we lay the groundwork that not only are we pursuing DOE funds, but that we also have a commitment from SPP, MISO and our customers in our membership that we have the other half of this bill covered."

Under the staffs' proposed JTIQ cost-sharing methodology, generators will pay 90% of the portfolio's cost and load will pay 10%. SPP load will pay about $71 million and MISO load about $29 million, without the DOE funding.

As with any discussion about allocating costs, several stakeholders raised concerns.

Steve Gaw, APA | © *RTO Insider LLC*

"I think all of us are seeing this DOE funding opportunity as a way to facilitate mitigating some of the concerns the stakeholders are expressing and the opportunity for that mitigation to really help make this a success," the Advanced Power Alliance's Steve Gaw said. "The second round of that application process, if the application makes it there, will be a very opportune time for additional comments of endorsement."

The Cost Allocation Working Group (CAWG) on Friday unanimously endorsed and recommended that the Regional State Committee approve the 90-10 allocation. It also recommended that:

- the 10% load portion of the JTIQ's annual transmission revenue requirement (ATRR) be based upon adjusted production costs, as outlined by the RTOs' joint operating agreement;
- the load portion of the portfolio's ATRR be regionally allocated on a load-ratio share basis consistent with previous RSC policies;
- each building transmission owner recover the non-capital cost component allocable to generation interconnection customers through a formula rate template in the building TO's region; and
- SPP's load share in the current portfolio and for the next study of the southern party of the MISO-SPP seam be regionally allocated on a load-ratio share basis consistent with previous RSC policies.

The motions all passed unanimously except for the last one, which Louisiana, North Dakota and Oklahoma opposed.

The RSC meets Jan. 30. Kelley said SPP plans to make the appropriate filings after the April round of governance meetings.

"We have to ensure we're in lock-step with MISO and its processes," he said.

GI Queue Continues to Expand

The JTIQ work will only result in more generation interconnection requests as SPP staff continue to work on reducing the backlog of requests in its queue.

Kelley said the SPP and MISO queues have grown since the JTIQ work began, with no end in sight.

"While we've made significant progress in clearing our existing backlog, there continues to be significant interest in developing new generation, both within the SPP footprint as well as MISO's," he said.

The backlog, which once stood at 651 requests and nearly 120 GW, had been reduced to 370 and 68.2 GW, respectively, in mid-December. However, the 2022 study cluster that closed in early January added 53.8 GW of requests, pushing the backlog to about 122 GW.

Many of those requests have yet to be validated by staff, leaving the *active queue* at 463 requests and just over 88 GW.

"It'll take a couple of months to evaluate the impact of this cluster. It's really, really big," SPP's Juliano Freitas told members, noting that the 2022 cluster exceeded forecasts by about 10 GW.

He said the new cluster is about 50% solar and 25% wind, in line with the active queue. Solar requests (39.2 GW) account for almost half the queue, with wind requests at 23.1 GW and storage at 12.9 GW.

SPP currently only has about 250 MW of installed solar capacity, said Casey Cathey, director of system planning. "That is kind of our next frontier."

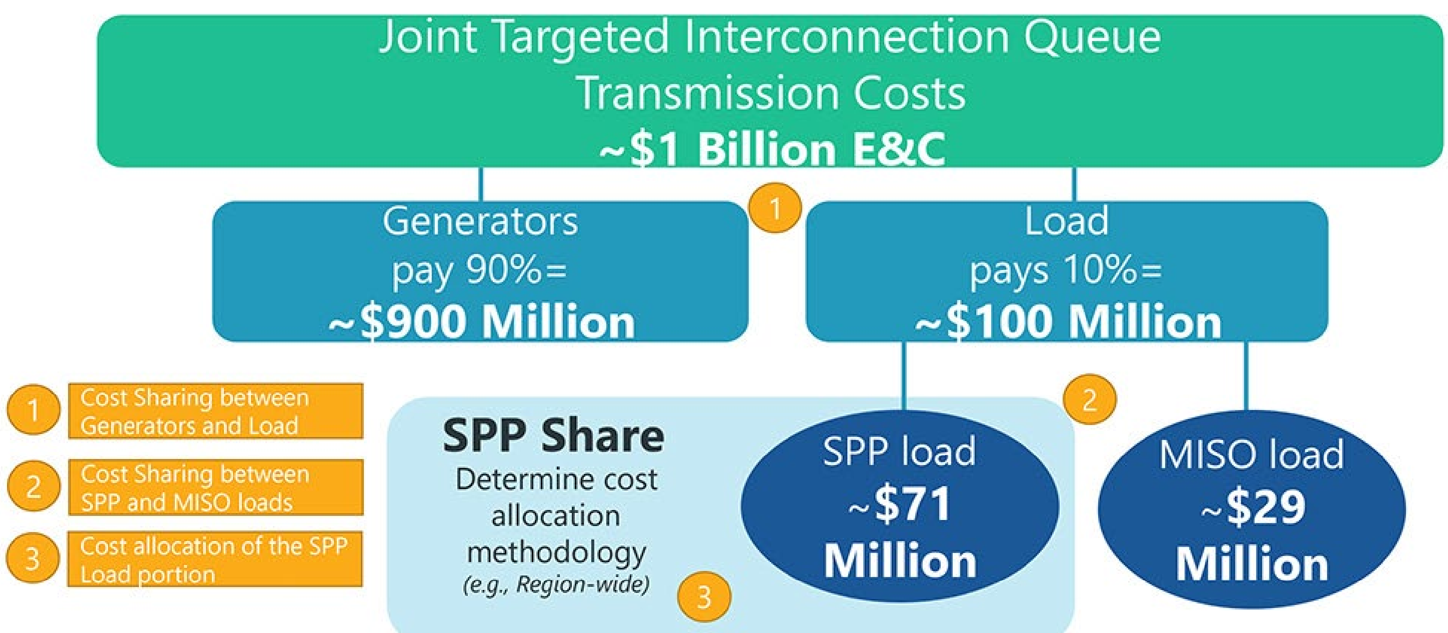
Freitas said that considering only about 40% of GI requests result in signed interconnection agreements, SPP could add more than 45 GW of capacity by 2028. The grid operator has added 27.7 GW of capacity since January 2017, executing 143 GI agreements.

Members Defer on PRM Deficiency RRs

The committee deferred action on a pair of revision requests related to deficiency penalties by load-responsible entities unable to meet the grid operator's new 15% planning reserve margin (PRM).

Following late changes to the two requests by stakeholder groups the night before the MOPC meeting began, committee members agreed to wait until a special conference call Friday to consider the change requests. That will give additional time to several stakeholder groups who have yet to approve the proposed revisions; the committee will then be able to endorse a recommendation for the RSC and the Board of Directors when they meet next week.

SPP is hopeful FERC will approve the revision



The proposed cost allocation for JTIQ projects. | *SPP*

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requests in time to accredit resources for the summer.

Staff have been working on the mitigation strategy at the board's direction since July. It became necessary when the board increased the PRM from 12% to 15%, effective next year, which left some members complaining they would not have enough time to meet the requirements. (See *SPP Board of Directors Briefs: Dec. 6, 2022*.)

COO Lanny Nickell has said the mitigation concepts include reducing the deficiency payment charge, extending the timeline to cure deficiencies and adding mechanisms to assure capacity.

RR536, proposed by SPP's Market Monitoring Unit, would replace the sufficiency valuation methodology's current penalty framework with a sufficiency valuation curve similar to the curve that NYISO uses to value capacity in its market. The curve starts at twice the cost of new entry (CONE) until regional accreditation reaches the sum of total noncoincident peak loads, then slopes downward to a net CONE value when regional accreditation reaches the PRM.

When accreditation exceeds the PRM, the curve continues its downward slope until it reaches $0 when regional accreditation reaches 1.15 times the PRM. By focusing on how valuable excess accredited capacity is to the market given the regional level of accredited capacity, this methodology shifts from a punitive approach to a tool that manages the current deficiency and properly rewards LREs with excess accredited capacity.

Staff worked with the MMU on RR536 and also drafted *RR537*, which clarifies that an LRE making the deficiency payment will be sufficient for this year's resource adequacy requirement. It also says that any entity receiving a deficiency payment cannot subsequently sell any of the excess capacity during the applicable calendar year.

"I think we're getting closer. Today is too soon, given the language was only provided last night," Evergy's Mo Awad said. "I would like to take some time and review the language."

Staff drew up a number of issues for stakeholder consideration, including clarifying that the waiver process is only in effect when the PRM increases; the timing of when generation must be committed to SPP, based on a deficiency megawatt amount; how the cost of new entry is broken into seasonal components; and simplifying megawatt allocation for the MMU's CONE process.

MOPC's leadership for 2023: Chair Alan Myers, ITC Holdings; staff secretary Lanny Nickell, SPP; and vice chair Joe Lang, Omaha Public Power District. | © *RTO Insider LLC*

The Supply Adequacy and Regional Tariff working groups will take up the revision requests on Tuesday and Thursday, respectively. The CAWG met Friday but did not vote on them; it has scheduled a special meeting for Wednesday.

December Storm Raises Same Issues

Staff told the committee that the December winter storm, while less severe than the February 2021 storm that forced the grid operator to shed load for the first time, still highlighted some of the same issues from two years ago.

C.J. Brown, director of system operations, said constricted fuel supplies and extreme cold weather-related outages led to some generation unavailability as surface temperatures in the SPP footprint were up to 25 degrees Celsius below historical averages.

Staff began receiving notifications on Dec. 20 from natural gas suppliers that non-firm usage of pipelines would be limited through Dec. 28. Ice floes on the Missouri River threatened several gigawatts of hydro generation, and the RTO's main control room operated on backup power during the event after the facility's transformer malfunctioned.

Empire Electric District and City Utilities of Springfield, Mo., near the Missouri-Arkansas border, experienced extremely low voltages on Dec. 23 caused by resource trips, lack of deliverability and parallel system flows. Empire had to shed about 25 MW of load for 15 minutes on Dec. 22.

Still, SPP was able to meet a peak demand of 47.2 GW on Dec. 22, a winter record.

Brown said that if the worst weather conditions had shifted to Dec. 23 or Dec. 24, SPP would have had 2 to 5 GW of capacity at risk.

"It doesn't mean we would have had load shed," he said, noting that the RTO could have reached energy emergency alert levels. "None of us want to be in a headline that says we shed load over Christmas. We need to get better information" from gas suppliers.

Midwest Energy's Bill Dowling cautioned SPP about taking comfort in the amount of gas generation it committed before the cold front blew in.

"It's one thing to know that [a gas unit] is committed a couple or three days in advance; … it's something else to get the gas," he said. "If the gas producers aren't producing and it doesn't show up in interstate pipeline, you're not going to get it, I don't care how much you paid for it."

Josh Phillips, who represents SPP at the North American Energy Standards Board, said the board's Gas-Electric Harmonization Forum is preparing a report on three main areas of concern during extreme weather events: fuel delivery assurance, communication practices and gas reliability.

Power generators and load-serving entities are underrepresented on the forum, Phillips said. He urged more industry participation as the final report delves into whether there's a need to require every gas generator to have firm gas supply and transportation contracts.

Dowling said that whenever he listens to discussions between the electric and gas sectors, "it ends up, 'This is your problem, electricity, so you have to change to meet our requirements.'"

"If [gas suppliers] declare *force majeure*, you just don't get your gas," said long-time MOPC

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member Bill Grant, now consulting for XO Energy. "The NAESB agreement needs teeth if they don't perform, that's the answer."

Brown said staff will complete its post-event review and gather lessons learned, while also participating in the FERC-NERC joint inquiry on the storm. They will continue to support resource adequacy efforts through the RSC and other stakeholder groups.

Members Endorse ITP Scope, STEP

The committee endorsed two stakeholder groups' recommendation to approve the 2024 Integrated Transmission Plan's scope, which includes assumptions not standardized by the ITP manual.

The assessment will study two futures — a reference case and an emerging technologies case — that assume between 49.9 and 54.9 GW of wind resources and between 14 and 22 GW of solar resources by Year 10. SPP currently has 32.5 GW of installed wind capacity and 14,000 turbines on its system, but only about 250 MW of solar, Cathey said.

The scope also includes peak and energy increases in both futures to account for electric vehicle growth and an approved methodology for retirements based on participants' resource plans. Staff used those plans to also determine wind, solar and storage capacity amounts. The study scenarios will assume all companies meet the PRM.

"We believe the two futures capture the necessary scenarios for building out the transmission system," Cathey said.

The committee also endorsed the *SPP Transmission Expansion Plan* (STEP), a comprehensive list of all transmission projects over a 20-year planning horizon. The report indicates that SPP members completed eight upgrade projects costing more than $40 million from last April to year-end. SPP issued 76 notifications to construct (NTCs) for $822 million during the same period; 12 NTCs were withdrawn.

Cathey reminded the committee that the 2022 ITP assessment was a reliability-only study, thus resulting in a smaller portfolio.

RAS Scheme Passes

The committee unanimously approved a consent agenda that included eight revision requests; an extension of the Transmission Owner Selection Process Task Force's sunset to Jan. 31, 2024; a waiver request to include the 2023 ITP needs assessment's market powerflow models (MPMs) and consider the 2023 ITP MPM violations in the 2024 ITP; and a sponsored upgrade study of NextEra Energy's proposal to add a 345/138-kV transformer at Oklahoma Gas & Electric's Cimarron substation.

SPP's Casey Cathey (left) catches up with long-time MOPC member Bill Grant, who represents XO Energy on the committee. Grant retired last June after 40 years with Xcel Energy, 16 of those on MOPC. | *© RTO Insider LLC*

Nebraska Public Power District had *RR505* pulled off the agenda for a separate vote, over concerns that the remedial action scheme (RAS) criteria would lead to unintended consequences. The change would supplant the need for approval conditions and clarifies RASes' appropriate uses. Members approved the revision request with a 95% vote.

Five other RRs, if approved by the Board of Directors next week, would:

- *RR519*: formalize the SPP operating criteria's requirement to perform an annual resource real-time availability evaluation and report findings and recommendations to appropriate stakeholder groups.
- *RR522*: clarify the use of the word "separately" ("Each facility must be registered separately with SPP…") to direct parties in the agreement to register each facility separately when they have multiple resources involved with the pseudo-tie agreement.
- *RR523*: modify existing *pro forma* generator interconnection agreements and language to provide a clearer indemnification standard with clearer language. The changes are modeled on PJM's interconnection service agreement.
- *RR526*: specify that a resource or an aggregation must be able to maintain a response of at least 0.1 MW for at least an hour to participate in the Integrated Marketplace; if the anticipated response drops below 0.1 MW, the resource must set its commitment status to "outage," consistent with recent FERC orders and SPP's current process.
- *RR528*: clean up Business Practice 7060 by using "evaluation" rather than "study" for projects that have been issued an NTC, aligning the term with how it is used when an NTC is re-evaluated through the ITP.

The consent agenda also included two other RRs that don't require board approval and go into effect immediately:

- *RR525*: deletes Business Practices 7100 (Designated Transmission Owner Qualification Process) and 7150 (Transmission Owner Selection when a Designated Transmission Owner Rejects a Notification to Construct), which became obsolete with the implementation of SPP's competitive transmission selection process.
- *RR529*: the annual cleanup to correct grammar, punctuation and acronyms in the production and/or forward looking protocols. ■

— Tom Kleckner

Company Briefs

Avista, NorthWestern Energy Agree to Colstrip Ownership Transfer

NorthWestern Energy will increase its share of the Colstrip Power Plant in 2026 under an agreement with Avista, the utilities announced last week.

Avista's 222-MW share of Colstrip is divided between Units 3 and 4. CEO Dan Vermillion said terms are still being finalized but that the company will keep its environmental cleanup liability, as well as its share of the Colstrip transmission line. John Hines, NorthWestern vice president of supply, said Colstrip would remain open through 2030. The end date was a break from the utility's repeated assertion that the plant would run through 2042. NorthWestern currently owns a 222 MW share of Unit 4.

The transaction is timed with Avista's state deadline to stop delivering coal power to its Washington customers by 2026.

More: *Longview News-Journal*

Former Duke Regulatory Director Joins McGuireWoods

Brian Franklin, a former Duke Energy regulatory director, has joined McGuireWoods' Charlotte location.

Franklin spent 15 years at Duke Energy, most recently as managing director of regulatory affairs for North Carolina.

McGuireWoods' regulatory and compliance lawyers represent clients in proceedings before FERC, the EPA, state public utility commissions and various state agencies.

More: *McGuireWoods*

WATT Coalition Announces New Chair, Executive Director

The WATT Coalition last week announced a new chair of the board in Hilary Pearson and a new executive director in Julia Selker.

Pearson is also the vice president of policy and external affairs at LineVision and has worked on clean energy policy for nearly 20 years.

Selker is the director of policy and strategy and chief operating officer for Grid Strategies. She previously worked for the Business Council on Sustainable Energy, the technology startup Faraday Grid, and interned with Congressman Peter DeFazio focused on energy and climate policy.

More: *WATT Coalition*

Shell to Acquire Volta

Shell last week announced it will acquire EV charging company Volta for $169 million.

Shell's purchase price of 86 cents per share is less than one-tenth the value that Volta's shares briefly reached after its August 2021 merger with SPAC TortoiseCorp II. The company's sale price is a far cry from its market valuation of $2 billion following its 2021 public-market debut.

Volta has a network of more than 3,000 public sites that combine EV chargers and video-advertising screens.

More: *Canary Media*

Arcimoto Idles EV Factory, Warns of Bankruptcy

Arcimoto last week announced it has shut down production at its Eugene, Ore., factory because it is nearly out of capital.

"We have halted our production of vehicles and will require substantial additional funding to resume production," Arcimoto said in a filing accompanying a stock offering. It warned that financing may not be available on any terms, and if not, "we will be required to cease our operations and/or seek bankruptcy protection."

The company moved to sell $12 million in additional shares at $3 each — less than half of last Tuesday's closing price. The stock plunged in morning trading Wednesday to $2.51.

More: *The Oregonian*

Federal Briefs

NRC: Entergy Waterford 3 Radiation Monitors Low-balled Readings

Improperly calibrated monitoring equipment at Entergy's Waterford 3 nuclear power plant in Louisiana could have low-balled the public health threat of radioactive gases released had there been an accident during a three-month period in 2022, the Nuclear Regulatory Commission said last week.

Entergy officials notified NRC inspectors during an Oct. 23 to Dec. 7 inspection of Waterford's emergency preparedness programs. Incorrect engineering conversion factors for measuring gases were loaded into the radiological dose assessment modeling software of two "wide range gas monitors" that are used in emergency responses. The errors resulted in readings that were 30.5% lower than the actual radiological conditions. The programming errors were corrected on Sept. 9.

The NRC will complete a final evaluation in 90 days to determine whether fines or other actions are required.

More: *The Advocate*

TVA Creates Independent Panel to Review Rolling Blackouts

The Tennessee Valley Authority last week created an independent review panel to study the events of a winter storm before Christmas that led to the agency implementing the first rolling blackouts in its history.

The panel will review what happened from Dec. 22 to Dec. 24 and why power plants failed to come online and/or stay online. This review will inform the independent panelists, who will provide feedback.

In addition to the panel, TVA is conducting meetings with the 153 local power companies in its region and with direct-serve customers about how they were affected by the blackouts.

More: *Knoxville News Sentinel*, *Chattanooga Times Free Press*

Renewables Projected to be a Quarter of US Generation by 2024

An EIA report projects that renewable energy will exceed 25% of the country's electricity generation for the first time in 2024.

From 2023 to 2024, the report projects that renewables would rise from 24% to 26% of the nation's electricity generation. Coal's share would drop from 18% to 17%; gas would remain the leader but drop from 38% to 37%, while nuclear would remain constant at 19%.

A variable is overall electricity consumption, as the EIA projects it to fall 1% in 2023 compared to 2022, before increasing 1% in 2024.

More: *EIA*, *Energy News Network*

Nevada Lithium Mine Project Gets $700M Conditional Loan Offer from DOE

The Department of Energy's Loan Programs Office recently issued a conditional commitment to lend up to $700 million to Ioneer's Rhyolite Ridge Lithium-Boron Project.

Demand for lithium is projected to exceed current global production capacity by 2030, driving U.S. automakers to seek "a robust domestic supply of materials to keep pace," DOE said in a statement. Once it is operating at full scale, the Rhyolite Ridge project is expected to produce enough lithium carbonate to supply about 370,000 EVs per year.

An Ioneer investor presentation from earlier this month identified DOE's loan commitment as a key source of debt financing for the project, which is expected to require a total capital investment of $785 million. Ioneer has invested $115 million in appraising and developing the project, and Sibanye-Stillwater in 2021 invested $490 million for a 50% stake in the project.

More: *Canary Media*

Enviros, Justice Company Reach Settlement over Mine Cleanup

Environmental groups last week announced they have reached a settlement with A&G Coal, a business owned by West Virginia Gov. Jim Justice's family, over the cleanup of three coal mines in Virginia's Wise County.

The settlement resolves a lawsuit filed by Southern Appalachian Mountain Stewards, Appalachian Voices and the Sierra Club over A&G's failure to clean up the Looney Ridge Surface Mine #1, Sawmill Hollow #3 Mine and Canepatch Surface Mine. The settlement calls for the reclamation of Looney Ridge by Aug. 31, Canepatch by Feb. 29, 2024, and Sawmill by Dec. 31, 2025. Failure to meet the deadlines will result in a $75,000 penalty for each site.

More: *Virginia Mercury*

BLM Seeks Public Input on Lava Ridge Wind Project

The Bureau of Land Management last week said it is seeking public comment on the draft environmental impact statement for the Lava Ridge Wind Project in Idaho.

The project is a proposed commercial-scale wind facility of up to 400 turbines to be constructed on about 84,000 acres of federal, state and private land.

The BLM intends to hold in-person and virtual public meetings during the comment period, which runs through March 21.

More: *KMVT*

Texas' Freeport LNG Export Plant Restarts Operations

Freeport LNG's export plant in Texas started receiving pipeline natural gas over the Martin Luther King Jr. holiday weekend, according to Refinitiv data.

Gas started flowing on Jan. 14 and was on track to reach 69 million cubic feet per day, according to the data. The last time gas flowed to Freeport was late December.

Freeport officials said the plant was slated to restart in the second half of January, pending regulatory approvals, after closing on June 8 because of a fire.

More: *Reuters*

Goff Named Principal Deputy Assistant Secretary for Nuclear Energy

The Department of Energy last week announced Dr. Michael Goff as its new principal deputy assistant secretary for the Office of Nuclear Energy.

Goff previously served as senior adviser to the office and held several management and research positions across the DOE, the national laboratories and the White House.

More: *Energy.gov*

State Briefs

ARKANSAS

Gov. Sanders Taps Webb to Head PSC

Gov. Sarah Huckabee Sanders last week named Doyle Webb as chair of the Public Service Commission. The appointment will run through Jan. 14, 2029.

Webb replaces Kimberly O'Guinn on the commission and Katie Anderson as chair.

More: *Arkansas Times*

CALIFORNIA

10 Public Entities Settle Dixie Fire Claims with PG&E

Ten public entities last week reached a col-

lective $24 million settlement with Pacific Gas & Electric for damages caused by the Dixie Fire in 2021, according to the Shasta County.

CAL FIRE said in January 2022 that the fire was caused by a tree coming in contact with distribution lines owned by PG&E. PG&E denied liability and reached the settlement to avoid further litigation.

The entities include Shasta County, Butte County, Tehama County, Plumas County, Lassen County, City of Susanville, Plumas District Hospital, Chester Public Utility District, Honey Lake Valley Recreation Authority and Herlong Public Utility District.

More: *KHSL*

Placer, El Dorado Counties Sue PG&E over Mosquito Fire

El Dorado County and Placer County, along with local agencies, filed a lawsuit against PG&E seeking damages for last year's Mosquito Fire.

The plaintiffs allege that PG&E's equipment was the cause and origin of the fire, which broke out on Sept. 6.

The Mosquito Fire burned for 50 days and scorched 76,788 acres. More than 11,000 people were evacuated.

More: *KPIX*

COLORADO

Mountain Parks Electric to Leave Tri-State in 2025

Mountain Parks Electric last week said it intends to leave Tri-State Generation and Transmission by Jan. 16, 2025.

Six of Tri-State's 42 members, including Mountain Parks, have given notice that they want greater flexibility in their procurement of generation.

More: *Big Pivots*

ILLINOIS

ComEd Seeks $1.5B Rate Hike over Next 4 Years

ComEd last week asked for a $1.5 billion rate hike, according to a filing with the Commerce Commission.

The utility's four-year, phased-in hike would include similar increases in power delivery rates in 2025 and 2026, followed by a slight reduction in 2027. By then, the average monthly residential bill would be about $17 higher (18%) than today's average of $93.

ComEd attributed the increase to bolstering the region's grid to phase out carbon emissions and protect the system from severe weather damage.

The commission has until December to decide whether the hikes are justified.

More: *Chicago Sun-Times*

Piatt County Places Moratorium on Wind Farm Permit Applications

The Piatt County Board last week placed a six-month moratorium on special use permit applications for wind farms.

The moratorium will allow the county to review the current ordinance and allow the state to finalize legislation concerning zoning for wind farms.

The board previously approved a moratorium in August 2020 as the zoning board and county were finalizing changes to the wind energy conversion ordinance. The moratorium was extended six months later and then expired once the board approved the changes.

More: *Piatt County Journal-Republican*

Princeton Council Tables Solar Array Resolution

The Princeton City Council last week voted 3-2 in favor of tabling a proposed resolution that would allow the construction of a solar array in the city's Technology Park.

The Municipal Electrical Agency filed a special use petition for the construction of a solar array that would occupy lots 12, 13 and 15 of the park, about 7 acres. Council Member Jerry Neumann moved to table the resolution to give city officials a chance to review information presented during the Jan. 16 meeting and decide what they feel is in the best interest of Princeton.

The resolution will appear on the Feb. 6 agenda.

More: *Shaw Local News Network*

KENTUCKY

McCracken County Solar Surrenders Conditional Use Permit

McCracken County Solar and its parent company, AES Clean Energy, last week decided to surrender its conditional use permit and withdraw its plans for a 60-MW solar facility in McCracken County. The companies also terminated a purchase power agreement with Big Rivers Electric Corporation.

McCracken County Solar cited a clause allowing it to terminate the agreement if the scheduled in-service date for any interconnection attachment facilities or network upgrades could not be completed by Oct. 31, 2022. AES Senior Development Manager Lauren Brunsdale previously said construction for the project had been delayed 18 times because of ongoing MISO interconnection study delays.

More: *The Paducah Sun*

MINNESOTA

Bill Requiring Carbon-free Electricity by 2040 Passes First Committee

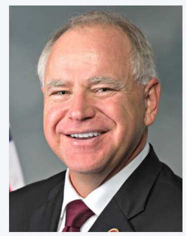
The House Climate and Energy Committee last week voted along party lines to approve a bill that would require the state's utilities to use only carbon-free sources by 2040.

Under the bill, utilities would need to increase the amount of their sales generated from renewable sources to 55% by 2035. They would also be required to have 80% of their electricity come from carbon-free sources by 2030.

The state's largest electric utilities, including Xcel Energy and Minnesota Power, have pledged to be carbon-free by 2050.

More: *MPR News*

Walz's Budget Proposal Calls for Weatherization, EV Infrastructure



Gov. **Tim Walz** last week released a budget proposal that calls for $2.6 billion in new spending over the next two years and $4.1 billion over four years.

New initiatives include energy goals of carbon-free electricity by 2040, building out EV infrastructure, encouraging solar power and helping people weatherize their homes.

More: *MPR News*

NEBRASKA

NPPD to Study Sites for New Nuclear Plant

The Nebraska Public Power District last week announced that it would study potential locations for a small modular reactor. The study will be funded through $1 million in federal dollars awarded by the Department of Economic Development.

NPPD Spokesman Grant Otten said the study will put NPPD in a better position should small modular reactors prove themselves and the district decide that nuclear power is something it wants to pursue.

The study will occur in two phases: determining the 15 best sites and then cutting them down to four. The first phase is expected to be completed this spring, while the second phase could take a year.

More: *Omaha World-Herald*

OHIO

W.H. Sammis Coal Plant to Shut Down by August

The W.H. Sammis coal power plant will shut down by mid-July, Energy Harbor said last week.

The company sent a layoff notice to the

state last week, saying that it plans to lay off 140 people who work at the plant. Terminations will happen on a rolling basis beginning in March.

More: *Cleveland.com*

VIRGINIA

Ford Disputes Reporting on Pittsylvania County Battery Project Pick

A Ford spokeswoman last week said the company had not made a site selection decision for an electric vehicle battery plant in partnership with a Chinese company.

The company statement came in response to a *Richmond Times-Dispatch* report citing two sources that said Ford had notified state officials that it had selected Berry Hill in Pittsylvania County for the plant prior to Gov. Glenn Youngkin scuttling the plan. Youngkin said the facts were "fundamentally wrong," but he refused to answer whether anyone had told him Ford had decided on Virginia.

Youngkin said he pulled Virginia from project consideration over concerns about Chinese government influence and the possibility of federal tax incentives benefitting a company with ties to the Chinese Communist Party.

More: *Richmond Times-Dispatch*

Senate Committee Rejects Clean Car Standards Repeal

The Agriculture, Conservation and Natural Resources Committee last week voted 8-7 to kill several Republican proposals to repeal the state's adoption of California's Clean Car standards.

The failed legislation would have untied Virginia from vehicle emissions regulations adopted by the California Air Resources Board and returned the state to federal regulations. In 2022, CARB adopted a rule that will ban the sale of new gas-powered vehicles beginning in 2035. Virginia's office of the attorney general has indicated it believes Virginia will have to do the same under the 2021 law linking the state with the California standards.

Republicans have argued the requirements of the rapid phaseout, including the target that 35% of new car sales be electric by 2026, are unachievable.

More: *Virginia Mercury*

WYOMING

Anti-EV Bill Dies in Committee

A bill aimed at phasing out the sale of electric vehicles in the state will not move forward as the non-binding resolution died in the Senate Minerals, Business and Economic Development committee last week when senators rejected the bill without taking a vote.

Sen. Chris Rothfuss (D-Laramie) said the global shift away from fossil fuels is an opportunity for the state, which is fertile ground for nuclear, wind and solar development and could invest in the lithium needed for EV batteries and the rare earth minerals needed for various green technologies.

More: *Wyoming Public Radio*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