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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

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Briefs

Correction

An article in last week's *RTO Insider* newsletter incorrectly referred to EPRI's Eknath Vittal as Eknath "Pattel." (See *Extreme Weather Workshop Hit by Extreme Weather*.)

RTO Insider apologizes for the error.

FERC/Federal News

FERC Nominees Set for a Quick Floor Vote as Schumer Files Cloture

By James Downing

President Joe Biden's three nominees to FERC are set for a floor vote as soon as next week with Senate Majority Leader Chuck Schumer (D-N.Y.) filing cloture on them June 5.

Energy expert Judy Chang, FERC staffer David Rosner and West Virginia Solicitor General Lindsay See all comfortably cleared the Energy and Natural Resources Committee on June 4, with leaders urging swift confirmation to maintain a quorum on the commission. (See related story, *Senate Energy Committee Advances Biden's FERC Nominees*.)

Two of the nominees would fill two open seats, and Chang would replace outgoing Commissioner Allison Clements, who congratulated them on their swift movement through the confirmation process in a post on X.

"As my term is ending, I intend for the June open meeting to be my last," Clements *posted*, along with a screenshot of the Senate Cloakroom's X feed showing Schumer's cloture motions. "More to say then, but for now — it has been my highest privilege and honor to serve."

Clements' term ends June 30. A quick confirmation would maintain FERC's quorum after Clements leaves, meaning it will be able to continue its normal business and vote out orders.

In addition to the leadership of the ENR Committee, several groups had also called on the Senate to move quickly to confirm the three nominees.

"It is vital that FERC [have] a full suite of commissioners as it goes through the rehearing process on Order 1920 and moves towards implementation," Electricity Transmission Competition Coalition Chair Paul Cicio said in a statement.

The Interstate Natural Gas Association of America, which represents the pipelines regulated by FERC, also called for swift approval of the nominees.

"With a pending vacancy in a couple of weeks, the agency could lose quorum, which would eliminate the commission's ability to approve construction of critical energy infrastructure projects, including natural gas pipelines and storage facilities," INGAA CEO Amy Andryszak said in a statement. "INGAA urges the Senate to act swiftly to avoid this loss of quorum by scheduling votes to confirm the nominations of Rosner, See and Chang with bipartisan support." ■

FERC nominees Judy Chang, David Rosner and Lindsay See prepare to testify before the Senate Energy and Natural Resources Committee. | © RTO Insider LLC

FERC/Federal News

FERC Chair: States not Benefiting from Grid Projects Won't Pay — Period

Phillips and Moniz Bring Provocative Perspectives to Exelon Innovation Expo

By K Kaufmann

OXON HILL, Md. — FERC Chair Willie Phillips did not expect his audience at the Exelon Innovation Expo to have read every word of the commission's 1,363-page *Order 1920*, which sets out to transform transmission planning in the U.S.

But in his June 5 keynote at the daylong event, he did pick out a few key provisions of the order and made a promise.

"State regulators must be and will be at the table when we decide what projects to select and how we will pay for them," Phillips said, speaking to a packed room of about 1,000 attendees at the MGM National Harbor Hotel & Casino. "And I'll tell you this right now: If you do not benefit from a project, you will not have to pay for it, period."

He also stressed the innovative elements of the order's approach to long-term planning for regional transmission, with a focus on reliability, affordability and sustainability.

"It makes sure that we look out over the long-term, 20-year horizon to make sure that we plan for the reality … on the horizon; that we consider a broad set of benefits when we do this planning, including grid-enhancing technologies," he said.

Similarly, Phillips described *Order 1977*, issued with 1920 on May 13, as a "breakthrough when it comes to how we engage with landowners and environmental justice communities" as part of FERC's backstop permitting authority for projects in federally designated National Interest Electric Transmission Corridors. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

FERC Chairman Willie Phillips delivers keynote at the Exelon Innovation Expo on June 5. | © *RTO Insider LLC*

Former Energy Secretary Ernest Moniz | © *RTO Insider LLC*

The order's Landowner Bill of Rights and requirements for project developers to submit Tribal Resource and Environmental Justice Public Engagement plans are intended to "make sure that these vulnerable communities are a part of planning for the new infrastructure that will power the American economy."

Speaking on the event's main theme — the role of innovation in the U.S. energy transition — both Phillips and former Energy Secretary Ernest Moniz covered by-now-predictable ground — the exponential growth in U.S. energy demand driven by data centers and artificial intelligence — and provided some individual and at times provocative insights.

Now CEO of the nonprofit Energy Futures Initiative, Moniz said current data center load growth signals that "we're just in the early stages of reindustrialization of the United States."

Phillips agreed, saying that "the technology revolution is an energy revolution … pushing the way we consume, the way we produce and the way we distribute our energy across the country."

Chip, battery and EV factories, and heat pumps are all in the mix, Moniz said, "and then we have wild cards that we still don't know how they're going to play out fully." For example, converting the country's current hydrogen production from natural gas to green hydrogen produced with electrolyzers could require about one-eighth of total U.S. electricity production, he said.

Moniz agrees with utilities calling for new natural gas generation to meet growing demand.

"I believe that is a reality," he said. "However, rather than treating this as a conflict, what I think we need to do is to take a more rational view of the clean energy transition. The word 'transition' there has meaning; it means we should not be looking at points in time, but a transition.

FERC/Federal News

"We have opportunities to design systems in which, if we have a little more carbon now to meet the load, we have to have a catch-up period during the transition in terms of the overall forcing of global warming. We can do that, but the discussion has to evolve around transition." Moniz did not elaborate on the impacts of such an approach, such as whether building new gas plants in the near term would increase the likelihood of future stranded assets to be paid for by utility customers, and he was not made available to respond to questions.

However, during his speech, he did say that other options for reducing emissions, such as carbon capture and sequestration and advanced or small modular nuclear reactors, "are clearly at least 10 years on the horizon, and that means you don't wait eight years to start planning it. That means you start last year to start planning it."

'Utilities Didn't Make the Cut'

Phillips also spoke about the connection between innovation and diversity.

"Most successful companies value innovation, and for those companies that value innovation, they also value something else; that's diversity; diversity of experience and diversity of thought," he said.

Phillips' efforts to bring that kind of diverse thinking to FERC are rooted in his own experience, he said, growing up in a single-parent household in Alabama, where he watched his mother spread out bills on the kitchen table to decide which to pay.

"Sometimes, utilities just didn't make the cut," he said. "So, it's never far from my mind, as I do this work, what real, everyday people — ratepayers — what they're thinking about; what they're struggling with to make their ends meet," he said.

Phillips sees the coming spikes in energy demand from a similar perspective. While demand is growing, the fact that "70% of our grid was built in the 1950s and 1960s" translates into an aging system where some regions are facing potential power shortages in the near term, he said. "For regulators like us, [the] question is, what do people do when they don't have the power they need? What do you do when the lights go out?"

Orders 1920 and 1977 are at least part of the answers to those challenges, he said.

Moniz called Order 1920 the "biggest step by FERC on transmission, probably in more than a decade." Planning for the clean energy transition, energy security and social equity should be "one conversation in the policy world," Moniz said. "It may be treated like three conversations, but it's not. It's one conversation, and that is the basis of long-term planning."

But more work needs to be done. Moniz sees demand aggregation and risk sharing as a critical part of long-term planning, pointing to a recent agreement by *Google, Microsoft and steel producer Nucor* to aggregate their demand and fund clean energy projects that can provide carbon-free power.

"Aggregating demand will again be part of the 20-year planning horizon and a way of sharing risk that the private sector can take on, and the public sector can work with the private sector on," he said. "There's no way we can accelerate the way we need to, I think, without all of that." ■

FERC/Federal News

USEA Event Looks into Addressing Growing Data Center Demand

By James Downing

Data center expansion is a major part of the power industry's return to demand growth around the country, and the United States Energy Association hosted a webinar June 5 with industry leaders on how the sector's growth will play out.

NERC for years forecast flat growth nationally, but that changed last year in part because of data center expansion to meet new computing needs from artificial intelligence. CEO Jim Robb said he expects growth will be even higher in the next long-term assessment. (See *NERC: Growing Demand, Shifting Supply Mix Add to Reliability Risks*.)

Growing demand makes ensuring resource adequacy more of an issue, but the scope of specific data centers can lead to challenges for the grid.

"We've seen and heard reports of interconnection requests on the order of 1 to 1.5 GW," Robb said. "And to put that in perspective, a gigawatt is about the entire load of the city of San Francisco. So, these are very, very large loads that are seeking to interconnect, and they're not diverse, right? So as load is either on or off, that has potential to create stability issues for the grid."

AI uses much more energy than a normal Google search, but over time, the difference should shrink because Nvidia, which manufactures much of the hardware for AI, is expecting its next generation of chips to use less power, Robb said.

"Algorithms will also get better over time," Robb said. "We saw this with the internet when the internet was first coming into broad scale adoption in the '90s and early 2000s. We had similar concerns around electricity demand that largely didn't actually occur because the chips got better. The algorithms got better. We will see something similar happen with the AI chips as well."

Data centers are very important to modern civilization, and while they do consumer a lot of power, they provide major benefits, said Christopher Wellise of Equinix, which builds data centers around the world.

"They do operate … 24/7/365, supporting a whole wide range of essential services, from the life-saving work in hospitals, to first responders, to powering global financial markets, managing food and pharmaceutical production, and so on," Wellise said. "Not to mention, of course, entertainment, communication and all the other things ... that folks rely upon."

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Some in the data center industry are putting multiple facilities at one site, and those can get up to 4 or 5 GW of demand, said Daniel Brooks, vice president of integrated grid and energy systems at the Electric Power Research Institute. (See *EPRI: Clean Energy, Efficiency Can Meet AI, Data Center Power Demand*.)

"That's a significant requirement in terms of additional supply and delivery capacity that has to be planned and permitted and constructed," Brooks said. "And the timelines for the development of the data centers themselves are on the order of ... one to two, maybe three years."

It takes longer than that to actually get new supply and new power lines sited, permitted and built: three to five years for a new gas turbine. Transmission can take even longer, he added.

Natural gas is going to be part of the grid for the near term; whether that is defined as five to 10 years or 15 to 20 is anyone's guess, said Dan Brouillette, president of the Edison Electric Institute.

"I don't suggest to you that that's what utilities want," Brouillette said. "That's just what is required by the physics of the problems that we're facing today. There's no way to stabilize the grid today without the use of some firm baseload power, and that includes natural gas. So, I think that you know, as I see it here, fully decarbonizing the grid, fully decarbonizing electricity production in the United States, it's probably not going to happen by 2030."

Even getting it done by 2035 is ambitious, but Brouillette said utilities would continue to "make every effort."

While demand from data centers is a growing issue, the industry has dealt with huge spikes from specific facilities in the past, especially at the start of the Cold War, when nuclear weapons production was ramping up, Brouillette added. Those manufacturing facilities consumed 10% of the electricity in the country.

The issue "boils down to a question of political will" and whether the facilities can be permitted, he added. ■

FERC/Federal News

Senate Energy Committee Advances Biden's FERC Nominees

By James Downing

Sen. Joe Manchin (I-W.Va.) | *Senate Energy and Natural Resources Committee*

The Senate Energy and Natural Resources Committee advanced all three of President Joe Biden's nominees to FERC with broad margins in a business meeting held June 3.

"Two of the five seats on the commission are already vacant, and a third will expire at the end of the month," committee Chair Joe Manchin (I-W.Va.) said, referring to Commissioner Allison Clements (D). "Confirmation of these three nominations will ensure that the commission has a full complement of five commissioners continuing important work. I believe all three are well qualified and intend to vote for all three."

Manchin, while still caucusing with the Democrats, recently *left the Democratic Party* to become an independent.

Clements' term expires June 30; if she leaves before a replacement is approved by a floor vote in the Senate and sworn in, FERC could lack a quorum. Commissioners can stay on past their term's expiration if a replacement has not been confirmed until Congress adjourns at the end of the year, but Clements has not said exactly when she plans to leave.

"By one estimate, the commission regulates activities that account for 7% of our nation's economy," committee Ranking Member John Barrasso (R-Wyo.) said. "And for that reason, we must fulfill our responsibility to maintain a quorum on the commission."

FERC was left without a quorum at the beginning of President Donald Trump's term for seven months, meaning it could not vote out any orders, and Barrasso said he does not want that situation repeated. He also supported all three nominees.

Several committee members voted against the nominees, but none were in doubt, with both David Rosner and Lindsay See advancing by a 16-3 vote and Judy Chang by 15-4.

FERC must have at least two members who are not in the president's party; the current makeup is 2-1, with Commissioner Mark Christie the lone Republican.

Rosner is a FERC staffer who was detailed to the ENR Committee and generated *opposition* from the left, with Sen. Bernie Sanders (I-Vt.) voting against him, despite being backed by the Democrats.

Chang, another Democratic pick, also faced some opposition from Republicans. She is a longtime industry expert who served as undersecretary of energy and climate solutions in former Massachusetts Gov. Charlie Baker's (R) Executive Office of Energy and Environmental Affairs.

The Republicans put forward See, who is the solicitor general of West Virginia, having argued that state's and others' cases against the Obama EPA's Clean Power Plan, which led to the "major questions" doctrine.

Sen. Josh Hawley (R-Mo.) voted against all three nominees as a protest against the Grain Belt Express transmission line being developed by Invenergy, which could be in a National Interest Electric Transmission Corridor designated by the Department of Energy — giving FERC backstop siting authority over its path through his state. (See *On the Road to NIETCs, DOE Issues Preliminary List of 10 Tx Corridors*.)

"FERC has the ability to countermand state authorities, essentially to bypass the state regulatory process and designate the land — including potentially taking it," Hawley said.

At their confirmation hearing, Hawley had asked all three nominees to guarantee they would take into account the interests of local farmers and residents and not "rubber stamp" DOE's corridors.

"I was particularly disappointed to [hear] the answer of Ms. See, who would not answer my question," Hawley said. "And I just want to say as a Republican, I'm not going to vote for other Republican nominees who will not stand up to the power grab that is happening all across the country, and of which my state in particular has been a victim."

In response, Barrasso read off a written answer See had given to that question that will sound familiar to anyone who follows FERC, where its members take pains to avoid stating their opinions on specific cases that come before them to avoid having parties file recusal motions against them.

Hawley "accurately asked" See to exercise caution when approving transmission lines, and she responded she would follow the law, Barrasso said.

"She went on to say, 'Sensitivity to how federal actions affect state and local communities is essential when making policy decisions,'" Barrasso said. "And she added, 'I would consider a proposal's consequences for local landowners important to the public interest analysis.'" ■

FERC/Federal News

Paper Examines How to Properly Value DER Grid Contributions

Use of Distributed Resources Can Reduce Grid Costs, Delay System Upgrades, Authors Contend

By James Downing

A new paper examines how the electricity sector can properly value distributed energy resources so they can be deployed efficiently as non-wires alternatives to reduce grid operating costs and delay system upgrades.

Published in the latest issue of *Electric Power Systems Research*, "*Valuing distributed energy resources for non-wires alternatives*" was written by Nicholas Laws, Michael Webber and Dongmei Chen of the University of Texas' Walker Department of Mechanical Engineering.

With electricity demand growing because of electrification, population growth and other factors, distribution utilities need to increase overall capacity and upgrade equipment to maintain reliability.

"However, those traditional actions related to the wires and poles of the distribution system might not keep pace with load growth that will accommodate rapid electric vehicle adoption or widespread installation of electric heat pumps as a way to reduce on-site fuel use for space and water heating," the paper said. "As a consequence, there is an acute need for non-wires alternatives that can be used to improve overall system performance. Some of those alternatives include demand response and distributed energy resources, such as local power generation and/or storage."

DERs can help meet growing demand at a lower cost than gold-plating the grid, but traditional utility funding models and market signals are not adapted to deploying them properly.

The trick is making it so that DERs and the distribution system both benefit from the investment. DERs can be built to serve a customer's need without any thought to their impact on the grid, but getting the price signals right can ensure they are available to address overloaded and other problem areas on the system.

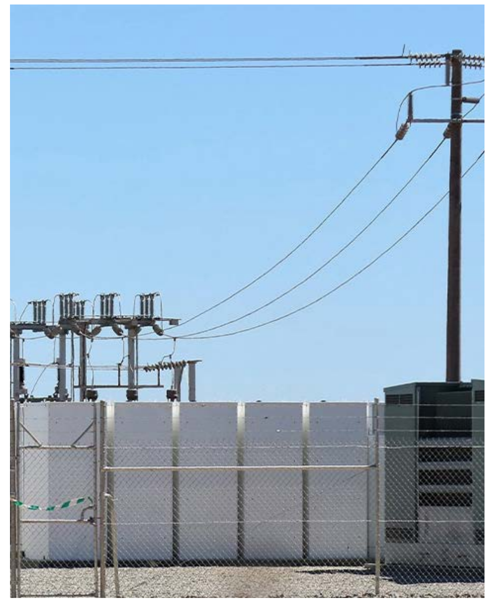
"Valuing DER for non-wires alternatives appropriately is a difficult task," the paper said. "The framework proposed in this work accounts for both the system planner's perspective and the DER investor perspectives."

The paper advocates for a "bilevel optimization framework" to minimize system planning costs while ensuring that DER developers get their required rate of returns.

Under FERC Order 2222, which requires all jurisdictional RTOs/ISOs to allow DER aggregations to participate in wholesale markets, system planners will have to work with DER investors to plan efficient distribution power systems.

The paper ran a study of the optimization it proposed on a 20-year lifecycle for some upgrades: including four power lines and three transformers.

Without any DERs or battery storage, it found upgrades would total $8.41 million, which fell to $6.43 million with the utility investing in batteries. While the batteries save money over time, they effectively doubled the upfront costs of the utility.



| *Shutterstock*

But paying DERs to do the same avoids the higher capital expenditure from the utility up front and cuts costs over 20 years to just $5.42 million. DERs cut back required grid upgrades to just one line and one transformer — instead of four lines and three transformers — while the batteries still required three lines upgraded and two transformers.

The right price signals can help DERs offset their costs through energy sales, which also lower systemwide power costs, the paper said. ■

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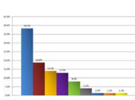

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FERC Allows Berkshire Utilities to Earn Market-based Rates in WRAP

Ruling Applies to PacifiCorp, Nevada Power and Sierra Pacific Power

By Robert Mullin

FERC on June 7 approved tariff revisions by Berkshire Hathaway Energy subsidiaries PacifiCorp, Nevada Power and Sierra Pacific Power that will enable the utilities to earn market-based rates when participating in the Western Resource Adequacy Program (WRAP).

As noted in the commission's order (*ER24-851*), the Western Power Pool's (WPP) WRAP does not intend to be a centralized market for capacity or energy, but rather a voluntary planning and compliance framework for resource adequacy that facilitates the ability of participants to meet capacity shortfalls through bilateral transactions.

"As proposed, transactions in the [WRAP's] Operations Program (notably the energy deployment and its associated total settlement price) would be market-based rate transactions conducted under existing authorities and frameworks on a bilateral basis between participants," the commission wrote.

The WPP's initial plan was to avoid requiring WRAP participants to file individual market-based rate filings and instead rely on a structure of indexed-based prices to settle the bilateral transactions, contending that the system would prevent the exercise of market power among participants.

Despite that measure, FERC was concerned that some participants would still be transacting in balancing authority areas (BAAs) in which they had been found to exercise market power, and that existing market-based rate requirements imposed on individual participants would still apply.

"With regard to the price index component of WRAP's structure, the commission found that the Western Power Pool's proposal was 'not sufficient to demonstrate that a price index may be used by specific participants that lack market-based rate authority or are subject to market-based rate mitigation,' as it failed to address whether the proposed index-based price was a just and reasonable rate for such participants," FERC noted.

But recognizing that existing restrictions on market-based rate authority (MBRA) could impede a participant's ability to transact at WRAP tariff-specified rates, the commission

FERC's ruling affects WRAP participants PacifiCorp, whose BAAs touch six Western states, and Nevada's Nevada Power and Sierra Pacific Power. | Western Power Pool

said such a participant could submit a Federal Power Act Section 205 filing "to seek new market-based rate authorization with appropriate mitigation or propose to amend its current market-based rate tariff to include tailored mitigation for the commission to consider."

No Market Power

In their Section 205 filings, the utilities pointed out they lack MBRA in their own BAAs, as well as in some first-tier — or interconnected — BAAs.

"They note, however, that the WRAP tariff obliges them to deliver physical power to a neighbor in need, which could be to a balancing authority area where their market-based rate authority is mitigated. They assert that complying with the WRAP tariff could cause them to exceed the authority in their market-based rate tariffs," the commission wrote.

The three utilities proposed to rely on the liquid hubs specified by the WRAP: Mid-C in Washington and Palo Verde in Arizona. The utilities contended they would not set the market price for any transactions in the WRAP and would be price takers, with all sales settled at the price index for each region.

"Applicants argue that allowing them to amend their market-based rate tariffs to use index prices when selling to counter-parties under the WRAP tariff would be just and reasonable under Order No. 697, where the commission stated it would allow mitigated sellers to use an index or locational marginal price proxy 'on a case-by-case basis based on their individual circumstances' rather than defaulting to cost-based rates," FERC wrote.

The utilities also argued that Mid-C and Palo Verde meet the commission's liquidity requirements for use in jurisdictional tariffs.

"PacifiCorp states that it routinely makes sales at both the Mid-C and Palo Verde hubs and has engaged in sales of millions of megawatt-hours at both the Mid-C and Palo Verde hubs since 2019. Nevada Power and Sierra Pacific did not make any representations about their sales at either the Mid-C or Palo Verde hubs," but they did note they trade more frequently at the Mead hub in Nevada, FERC said.

PacifiCorp said it trades only lightly at Palo Verde and, while trading more heavily at Mid-C, it does not report its transactions at either hub to price indexers and therefore could not influence the WRAP settlement price at either hub.

The commission clarified that its acceptance of the changes to the market-based rate tariffs for the utilities is limited to WRAP transactions and predicated on program provisions that restrict the potential for the exercise of market power.

"As applicants note, under the WRAP design, when load-responsible entities choose to join WRAP, once committed under the Operations Program, they are obligated to comply with its requirements, including requirements to make non-discretionary sales, or face charges for noncompliance," the commission wrote. As such, the applicants and other participants in WRAP will have no discretion as to: whether to make a sale; the quantity of any sale; or the price of any sale. For any such sale, the applicants will act as a price taker and, therefore, will not know the WRAP settlement price until after the markets close."

But the commission also required the utilities to include in their triennial market power updates to details about their "transactions at or near the Palo Verde and Mid-C hubs, relative to the total volume of transactions at the Palo Verde and Mid-C hubs, respectively, to allow the commission to evaluate the applicants' sales contribution to index formation." ■

CAISO/West News

Market Footprint Critical for EDAM Decision, NV Energy Says

Nevada Utility Explains Reasons for Joining CAISO Day-ahead Market in IRP Filing

By Elaine Goodman

The growing footprint of CAISO's Extended Day-Ahead Market (EDAM) was a critical factor in NV Energy's recently announced decision to join it rather than the competing Markets+ offering from SPP, the utility said in a regulatory filing.

PacifiCorp, the Balancing Authority of Northern California, Los Angeles Department of Water and Power, and Portland General Electric, as well as CAISO, are all expected to participate in EDAM. In addition, Idaho Power has said it is leaning toward EDAM as its day-ahead market choice.

The expected EDAM lineup "provides a significant degree of interconnectivity and supports a diversity of resources," said Ryan Atkins, NV Energy's vice president of resource optimization and resource planning.

Atkins' comments are from written testimony included in the company's 2025-2027 integrated resource plan, filed with the Public Utilities Commission of Nevada on May 31. The commission made the filings public June 5.

CAISO's recent approval of the Southwest Intertie Project-North (SWIP-North) was another key factor in NV Energy's decision, Atkins said. A joint project by NV Energy and LS Power, SWIP-North will be a 285-mile, 500-kV line to send Idaho wind energy to markets to the south. It will connect to the One Nevada (ON) Line at Robinson Summit, a site that will eventually be one corner of a transmission triangle across Nevada when NV Energy's Greenlink North and Greenlink West lines are completed. (See *CAISO Board Approves Nevada Transmission Line to Access Idaho Wind*.)

SWIP-North "will only enhance the transfer capability of the existing ON Line transmission line in Nevada, bringing even greater benefits to all EDAM participants," Atkins said.

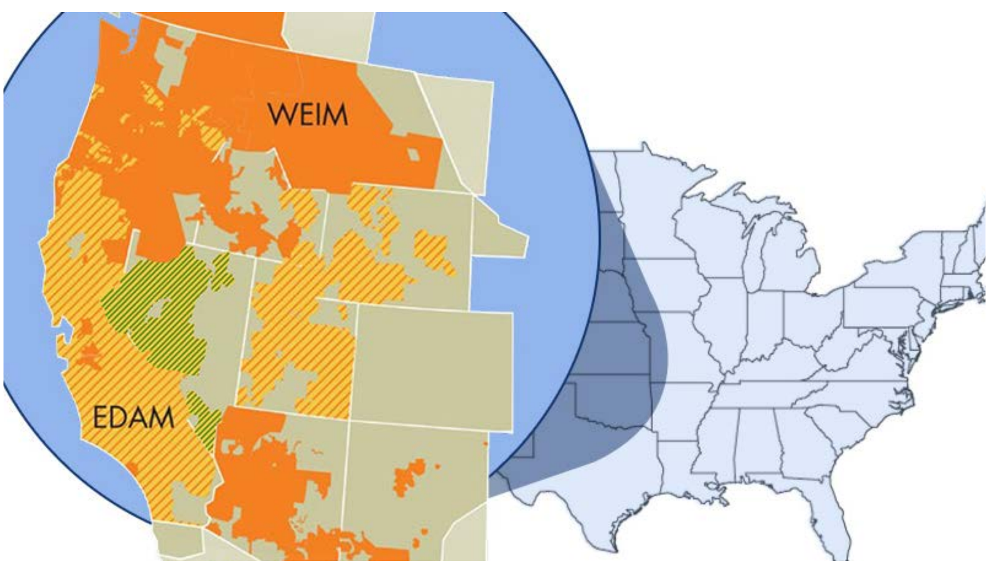
Atkins also noted the "significant economic, reliability and environmental benefits" that NV Energy has gained through participation in CAISO's Western Energy Imbalance Market (WEIM). Since joining the WEIM in December 2015, the utility has reaped $488 million in benefits.

Although NV Energy stated in its IRP that it plans to join EDAM, the utility will file a separate, formal proposal later this year seeking PUC approval to join the day-ahead market.

In a June 6 *release*, CAISO called NV Energy's intent to join EDAM "a substantial milestone in advancing the efficient coordination of the electric needs for growing loads and a changing resource mix across the West."

'Least-cost, Least-regrets' Decision

NV Energy's announcement of its EDAM choice may be a central piece in the day-ahead market puzzle in the West.



NV Energy's balancing authority area is a central transfer point for energy flows in the Western EIM and will continue to be so for the EDAM when the utility begins participating in that market. | *CAISO*

As competition for day-ahead market participants has been heating up between CAISO and SPP, many potential participants have indicated they are waiting to see who will join each market before making their own decision.

Entities that have shown the most interest in joining Markets+ include the Bonneville Power Administration and Puget Sound Energy in the Northwest, and Arizona Public Service, Salt River Project and Tucson Electric Power in the Desert Southwest. NV Energy's balancing authority area sits between those two areas.

The comments in the IRP are the latest confirmation of NV Energy's intent to join EDAM.

David Rubin, NV Energy's federal energy policy director, confirmed the utility's decision May 31 during a meeting of the Launch Committee for the West-Wide Governance Pathways Initiative. (See *NV Energy Confirms Intent to Join CAISO's EDAM*.)

Before that, NV Energy had disclosed its decision to join EDAM during private meetings, multiple sources previously told *RTO Insider*.

In his testimony, Atkins also addressed the question of how NV Energy plans to meet a Nevada requirement to join an RTO by 2030.

"Events in the West are still too fluid, and the requirement dates still far enough out, to make any judgments about [NV Energy's] ability to meet the Jan. 1, 2030, requirement," he said.

Atkins described the decision to join EDAM as an incremental step to capture "substantial customer benefits on a least-cost, least-regrets basis."

Last year, the PUC opened a docket to explore ways to evaluate a utility's request to join a regional market or RTO. (See *Nevada RTO Proceeding Examines EDAM, Markets+ Design*.)

In a May 20 procedural order, Commissioner Tammy Cordova laid out 18 topics that NV Energy should address in an application to join a day-ahead market.

Those include governance, cost of participation, greenhouse gas tracking, impacts on non-jurisdictional transmission customers and pathways to joining an RTO.

Another topic for consideration is any investment in generation and transmission that would be needed to participate in the market or maximize its benefits. ■

CAISO/West News

WECC Flags Hydro in BC, SW Heat as Potential Summer Concerns

Drought in Canada, Desert SW Heat Waves Could Threaten Grid Reliability

By Ayla Burnett

Extreme heat in the Desert Southwest and low hydro conditions the Northwest could pose reliability problems for the Western Interconnection this summer, although the region isn't at an alarming risk for grid emergencies, WECC officials said during a June 5 call.

Those officials delved into the regional entity's findings that became part of NERC's *2024 Summer Reliability Assessment*, which showed British Columbia, the Southwest and Baja California at an "elevated" — but not "high" — risk this summer, which indicates a "potential for insufficient operating reserves in extreme conditions." (See *NERC Summer Assessment Sees Some Risk in Extreme Heat Waves*.)

Despite that assessment, Kris Raper, WECC vice president of strategic engagement and external affairs, cautioned call listeners about how quickly conditions could deteriorate, noting that industry participants know the West has "had some really tight summers recently."

"Until we can get more resources and more transmission online to be able to get the energy from where it's generated to load and have a broader perspective and purview of where that energy can come from, then we have to know what it is that we're looking at and what the risks may be," Raper said. "And right now, the risks are greater than they've ever been."

A trend of rising temperatures and an increased rate of load growth has fueled steady increases in summer peak demand in the West in recent years, and this year is expected to be no different, WECC officials said.

Data from the National Center for Environmental Information indicates a 61% chance that 2024 will be the hottest year on record and a 100% chance it will be in the top five, said Matt Zapotocky, senior reliability assessments engineer at WECC.

Investing in additional capacity is crucial to accommodating the increasing frequency of heat waves, Zapotocky said. Inverter-based resources (IBRs), which include renewables and battery storage, make up the bulk of capacity additions in the Western Interconnection, with the latter increasing "exponentially" between 2019 and 2023, from 230 MW to almost 10 GW. Solar resources nearly doubled from 19 GW to 35 GW over that time, and wind resources increased from 25 GW to 37 GW.

An additional 32 GW of proposed capacity is projected in 2024, with about 80% of that being IBRs. WECC also expects 1.6 GW of mostly thermal resources to be retired.

While no Western regions are projected to experience a loss-of-load event this summer, according to WECC's assessment, some regions, such as British Columbia, are at a greater risk than others.

While hydroelectric resources and reservoir levels — particularly in California — are in a better position than they've been in the recent past, conditions have not returned to historical norms, said Bryon Domgaard, a senior analyst at WECC. Drought remains in British Columbia, where hydro resources make up 90% of the resource portfolio. Additionally, the province is undergoing rapid electrification in the industrial, commercial and residential sectors, but there are no planned capacity additions for the summer ahead, he noted.

"That reduction in hydro availability is really what is concerning for British Columbia. In addition, the transfer capacity has been diminishing over the past couple years as we see more load growth in the Pacific Northwest taking out some of the transfers that used to make it to British Columbia," Zapotocky said. "These concerns, coupled with the increase in demand in British Columbia from electrification, placed it in that elevated risk category."

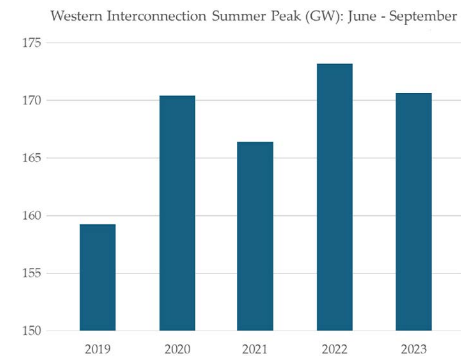
The Desert Southwest also sees elevated risk because of heat-related extreme weather. The potential for high temperatures to cause derates for natural gas-fired generators coupled with escalating demand could lead to loss of load, Zapotocky said.

In California and Mexico, supply chain issues for obtaining grid equipment are of greater concern.

"Not being able to complete their projects on time could result in escalating the small amount of loss-of-load hours that we're seeing in that region," Zapotocky said. "Which reliability risk is most pertinent depends on which region we're discussing."

While increased coordination continues to be crucial for mitigating risk, interconnectivity in the system also adds new complexities.

Solar proliferation in California and Mexico has boosted south-to-north transfers into the Northwest, causing concerns about hitting



Peak demand in the summer has been increasing steadily in the West over the past four years, according to WECC. | *WECC*

system operating limits on paths between the two regions, Zapotocky said. And despite seeing more transfers from California to the Northwest, fewer of the transfers are making it to Canada. As British Columbia is forced to serve more of its own load, the system in other regions, such as Alberta, can experience reduced transfer capability.

"When it's near islanding conditions — when IBR outputs are high and demand is low — there's actually difficulty maintaining frequency response in that region, and this can potentially result in additional under-frequency load shedding. So really, everything is kind of interrelated here," Zapotocky said.

With the influx of IBRs, areas in the Desert Southwest also are experiencing increased frequency issues.

Working Together

Demand response programs have been "instrumental" in reducing peak demand during stressed grid conditions, Domgaard said. But they face limits becauase of decreased customer participation in the face of increased DR events, and they should be reserved for emergencies.

Working together remains the priority in ensuring reliability across the Western Interconnection, said Katie Rogers, WECC manager of reliability systems.

"If there are wildfires going on in California, if there's a drought that's affecting hydro availability up in the north, how can the subregions and [balancing authorities] in the whole of the Western Interconnection work together so that someone isn't stranded?" ■

CAISO/West News

NV Energy IRP Describes $1.76B Cost Jump for Greenlink Projects

Materials, Labor, Environmental Mitigations Boosting Expenses, Utility Says

By Elaine Goodman

Rising costs of materials and labor and an increased use of H-frame structures as an environmental mitigation have contributed to a $1.755 billion increase in the projected cost of NV Energy's Greenlink transmission projects.

The costs for Greenlink North and Greenlink West, estimated at $2.484 billion in 2020, grew to $4.239 billion as of May 2024 — a 70.6% increase.

NV Energy disclosed the figures in its 2025/27 integrated resource plan, filed with the Public Utilities Commission of Nevada on May 31.

Of the $1.755 billion cost increase for the Greenlink projects, NV Energy attributed $340 million to the rising costs of materials, equipment and labor.

"Inflation has played a major role," Shahzad Lateef, NV Energy's senior project director for transmission development, said in the filing.

The Bureau of Land Management is requiring NV Energy to use an additional 160 miles of H-frame structures to mitigate risk to desert tortoise and sage grouse habitat, an extra cost of $124 million. Shorter span lengths and more expensive materials contribute to a 42% higher cost for H-frame structures compared to the guyed-V lattice structures that were previously planned, according to the filing.

Other environmental mitigations will add about $30 million to Greenlink costs.

Costs have also gone up $252 million because of changes in project scope, NV Energy said, and new estimates have added $101 million in sales and use taxes that weren't previously included.

'Vital' to Renewables

Greenlink West will be a 525-kV line along the west side of Nevada from Las Vegas to the Fort Churchill substation near Yerington. In Northern Nevada, Greenlink North will connect the Robinson Summit substation near Ely to Fort Churchill via a 525-kV line.

The Greenlink lines, combined with the existing One Nevada line, will form a transmission triangle around the state.

NV Energy's estimated cost for its Greenlink North and Greenlink West transmission projects has grown from $2.484 billion in 2020 to $4.239 billion. | *NV Energy*

"The Greenlink projects are vital to the robust development of renewable resources throughout Nevada as well as low-cost reliability for the growing load," Ryan Atkins, NV Energy's vice president of resource optimization and resource planning, said in the filing. "The Greenlink project remains the best alternative to meet [NV Energy's] future transmission needs despite the cost increases."

Breaking down the costs by project, cost estimates for Greenlink West have increased from $1.22 billion in 2020 to $1.907 billion. Greenlink North costs have gone from $854 million to $1.490 billion.

And the costs for "common ties" in the project — including a substation expansion at Fort Churchill and 345-kV connecting lines to nearby areas — have grown from $410 million to $841 million.

John Tsoukalis, a principal with The Brattle Group, also provided testimony regarding the Greenlink projects as part of NV Energy's IRP filing.

Tsoukalis said the Greenlink projects would increase the resilience of the NV Energy system, particularly in the case of an outage of the One Nevada Line.

Greenlink could also increase interconnections with nearby entities, potentially enhancing the benefits of NV Energy's participation in the Western Resource Adequacy Program (WRAP), Tsoukalis said.

Tsoukalis estimated the Greenlink projects would reduce costs to NV Energy customers by $50.8 million per year. Customer benefits would increase by about $57.3 million a year, as operating costs and purchased power costs declined and off-system sales revenues grew by $38 million a year, he projected.

Those gains would be slightly offset by reductions in short-term wheeling revenues, market congestion revenues and bilateral trading profits.

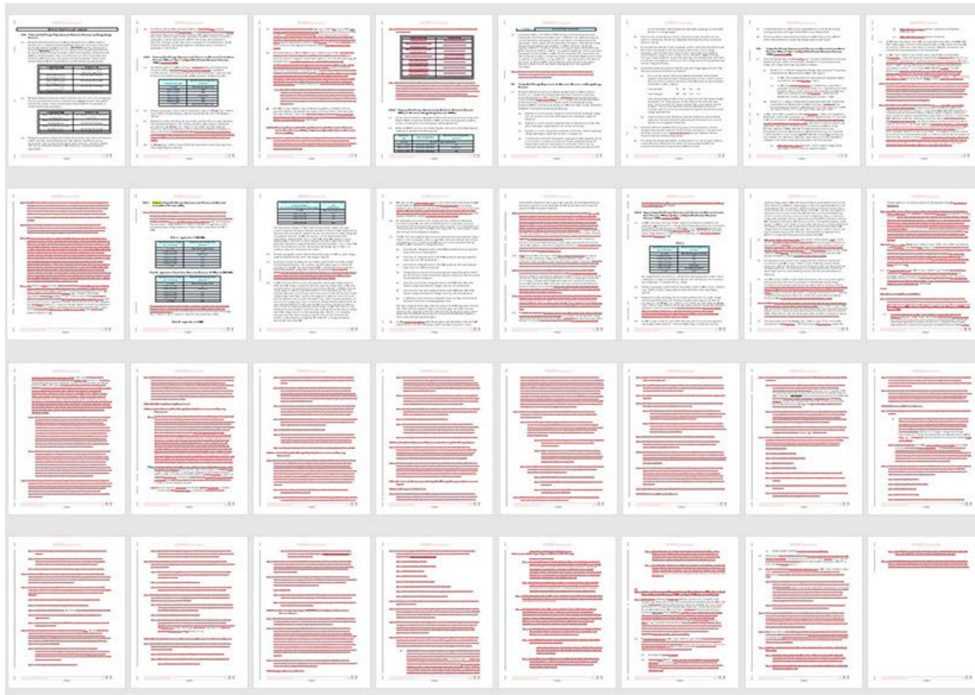
The next steps in the BLM permitting process for Greenlink West will be publication of the final environmental impact statement, expected this month, followed by a record of decision in August and a notice to proceed in December.

For Greenlink North, BLM is expected to release a draft environmental impact statement in July. ■

ERCOT TAC Endorses Rule for Inverter-based Resources

Stakeholders, Staff Resolve Differences After Months of Negotiation

By Tom Kleckner



NOGRR245 went through many red-lined versions. | *ERCOT*

ERCOT stakeholders and staff came to an agreement last week on a rule change that imposes voltage ride-through requirements on inverter-based resources, a result of more than a year's worth of back-and-forth redlined comments and negotiations.

During a special June 7 conference call, the Technical Advisory Committee endorsed a change to the Nodal Operating Guide (*NOGRR245*) that aligns ERCOT's rules with NERC reliability guidelines and the most relevant parts of the Institute of Electrical and Electronics Engineers' *standard* for IBRs interconnecting with the grid.

ERCOT's Board of Directors remanded the NOGRR back to TAC in April, directing the language — approved by the committee over staff's objections — be modified to address staff's reliability concerns. (See *ERCOT Board of Directors Briefs: April 22-23, 2024*.)

A pair of IBR-related voltage disturbances in West Texas in 2021 and 2022, dubbed the Odessa Disturbances, only added urgency to the measure's eventual passage. (See *NERC Repeats IBR Warnings After Second Odessa Event*.)

TAC has held a workshop and two conference calls devoted to NOGRR245 since April.

Staff said the revisions in their *latest comments*, submitted June 5, addressed their concerns and reflected TAC discussions offering compromise on generation interconnection agreements, requiring all IBRs maximize up to the equipment's full capability. Staff said they will support an exemption process allowing them to assess reliability risk and costs during a review and a one-time exemption process with no after-the-fact exemptions for performance failures or later discovery.

However, staff said they would not support a "subjective commercially reasonable" standard and would only support considering cost during the exemption process if the solution is "clear, objective, quantifiable and repeatable regardless of technology, unique commercial characteristics or plant age."

("Commercially reasonable" is defined as terms "conducted in good faith and in accordance with commonly accepted commercial practice.")

TAC accepted the comments but added gray-box language with potential modifications that would enable entities to meet the applicable ride-through requirements when they have not yet added a "technically feasible" change. The modifications are for those entities where the upgrade costs are less than 40% of the full, in-kind replacement cost of a plant's inverters or turbines and converters.

Members accepted a friendly amendment to extend the gray-box language's effective date from August to March 2025.

Speaking for the *ad hoc* "joint commenters" stakeholder group, Eric Goff said the group's *latest comments* represent a "serious and good faith commitment" to making the upgrades. He said their comments have been updated to allow for immediate implementation of the standards and to decouple software and more expensive hardware ride-through considerations.

"We think that this maximization procedure meets ERCOT's goals. … I think we have the same intention and desires or very similar intentions and desires," Goff said.

TAC endorsed the NOGRR by an 18-1 margin, with 10 abstentions. Demand Control 2, a member of the retail segment, cast the lone opposing vote. The municipal, retail and power marketing segments accounted for nine of the abstentions.

Demand Control 2 CEO Chris Hendrix told *RTO Insider* that the joint commenters' proposal was not posted until the night before the conference call and didn't allow enough time for full consideration. He also said ERCOT's 40% threshold for replacement costs was arbitrary, "extremely" high, and didn't consider the life of generating units or existing contracts.

"Either the threshold should be a lot lower or some aspect of commercial reasonableness added," he said.

Hendrix motioned to table the change. However, he was unable to secure a second.

TAC members did not celebrate the NOGRR's passage, although American Electric Power's Richard Ross did promise to award Luminant's Ned Bonskowski with one of his Gold Star awards for staying up until 2 a.m. June 7 to compare the ERCOT and joint commenters' proposals.

"I've never received a higher honor in my professional career," Bonskowski said.

"Don't forget to put that on your performance review," Ross replied. ■

ISO-NE News

State Regulators Discuss Affordability, Utility Incentives at NEECE

Mass. Legislators Give Briefing on Permitting Reform Efforts

By Jon Lamson

MYSTIC, Conn. — Top utility commissioners from four New England states emphasized the need for regulatory innovation to preserve affordability amid the clean energy transition at the New England Energy Conference and Exposition (NEECE) on June 5.

"Inequity is probably the most significant concern when it comes to the clean energy buildout," said Ed McNamara, chair of the Vermont Public Utility Commission.

As transmission and distribution costs associated with enabling electrification accelerate, protecting low-income customers will become increasingly important, McNamara said.

"The customers with low incomes are not the ones buying [electric vehicles] or installing heat pumps," he said. "They're not benefiting from more stable heating and transportation prices due to electrification, but they're still paying the cost to upgrade the distribution grid."

Marissa Gillett, chair of Connecticut's Public Utilities Regulatory Authority, said regulators' primary job is to interpret legislative directives and find "the most cost-effective way to implement the policy goals that are being articulated."

"I've been a huge proponent of utility regulators taking more of a driver's seat position," Gillett said. She stressed the importance of including communities that have not historically been involved in utility proceedings. "The more perspectives we have at the table the more robust our decision-making will be."

Gillett said one of the major challenges for regulators in the clean energy transition is the "information asymmetry that all utility regulators — and frankly stakeholders — have to grapple with."

"I don't think there's any malintent to it; it's just a simple reality of utilities having information, and utility regulators really having to learn how to ask the right questions and be prepared with new and creative ways to interpret data," Gillett said.

Gillett has overseen the PURA's implementation the legislature's *mandate* for a new performance-based regulation framework and has *aggressively pursued* increased utility accountability. The state's utilities have been outspoken in their criticism of the new direction, complaining in public and behind the scenes about the state's regulatory climate and arguing that it is harming their ability to raise capital.

Several other regulators also spoke about the need to reconsider utility incentive structures amid the clean energy transition.

"We definitely need to move [toward] stronger performance incentives that are really driving outcomes," said Philip Bartlett, chair of the Maine Public Utilities Commission. "The key is to make sure [utility investments] are going to the places that are going to get us the biggest bang for our buck."

Jamie Van Nostrand, chair of the Massachusetts Department of Public Utilities, said regulators should be looking at "incentive mechanisms to align [the utilities'] interests with our interests in pursuing clean energy goals and maintaining affordability."

Van Nostrand specifically emphasized the need to support the deployment of virtual power plants and demand-side efforts to reduce the overall need for distribution infrastructure.

Regarding transmission, Van Nostrand said there have been "huge technological breakthroughs over the last decade or so, whether it's advanced reconductoring or grid-enhancing technologies, that could really potentially increase the capability of our transmission grid to carry more load."

"But we also know there's a capex bias," Van Nostrand said. "Utilities tend to want to build more stuff because they get to put it into the rate base and get a return on it. It's our job as regulators to make sure … that utilities are considering this new technology than can potentially reduce costs."

Bartlett, who chairs a New England Conference of Public Utilities Commissioners *working group* on retail demand response, said well-designed time-of-use rates and DR programs can provide "a real opportunity" for cost-constrained customers to lower their electric bills.

Effectively reducing demand could also "dramatically reduce the buildout of the grid" and provide cheaper solutions to preserving grid reliability during the most stressful hours of the year, he added.

"If you can save hundreds of millions of dollars in new programs and fixes to keep things reliable, that's huge," Bartlett said.

The event was the 30th annual NEECE, which is organized by the Connecticut Power and Energy Society and Northeast Energy and Commerce Association.

Massachusetts Legislative Update

Massachusetts Rep. Jeffrey Roy, co-chair of the state legislature's Joint Committee on Telecommunications, Utilities and Energy (TUE), gave an update on clean energy legislation currently under consideration.

The legislature's previous two sessions have both produced significant climate bills, but lawmakers are running out of time to pass a bill by the end of the current session, which will conclude at the end of July. (See *Mass. Lawmakers Aiming for an Omnibus Climate Bill in 2024*.)

While lawmakers are considering a range of proposals related to EV charging, power purchase agreements, advanced metering infrastructure, building decarbonization and retail electricity choice, the top clean energy priority for many in state government appears to be permitting and siting reform.

"There is nothing more important to our clean energy goals than siting and permitting reform," Roy said. He called the current siting process in Massachusetts "slow, complicated and intricate."

Mary Beth Gentleman, former assistant secretary at the Massachusetts Executive Office of Energy Resources and a member of the state's *Commission on Energy Infrastructure Siting and Permitting*, said the state should be permitting "at least six times the amount of clean energy infrastructure as we are currently permitting."

Gentleman said transmission and distribution projects typically take seven years from application to the end of the appeals process.

"At that rate there is little chance that we will be able to comply with the state carbon mandates," Gentleman said. "Problem No. 1 is there are too many state and local permits, and all of them can be appealed." Consolidating all required permits into a single process could simultaneously speed up the review and make it easier for the public to participate, she said.

Roy said he is discussing permitting reform with his TUE co-chair, Sen. Michael Barrett, and the Healey administration to "craft a bill we can all agree on."

"I'm confident that we're going to get a piece of legislation done by July 31," he said. ■

ISO-NE News

Chicago Law Prof Takes ISO-NE to Task at Consumer Liaison Group

RTO Presents Strategy for Implementing More DR

By Jon Lamson

HOLYOKE, Mass. — Governance structures and market rules at ISO-NE that favor incumbent interests have contributed to pushing the region into costly and carbon-intensive reliability solutions, University of Chicago Law School professor Joshua Macey told the RTO's Consumer Liaison Group (CLG) on June 4.

Speaking to NEPOOL members, ISO-NE officials and members of the public at Holyoke Community College, Macey said the voting power of incumbents within NEPOOL has led to a bias toward capital-intensive solutions to reliability concerns.

"Reliability regulations are increasingly coming into tensions with clean energy policies," Macey said, pointing to the reliability-must-run agreement for the Mystic Generating station and ISO-NE's *inventoried energy program*, which compensates resources for keeping stored fuel on hand in the winter. The program is set to expire at the end of February.

"This is the type of intervention that essentially renders any type of clean energy policy irrelevant," he said, arguing that out-of-market fuel security interventions constitute an admission that the capacity market is not adequately serving its reliability function.

He argued that ISO-NE's capacity market has had small penalties for generators that can't run when called upon. In 2014, "a resource could have met none of its obligations and still made a profit in the capacity market," he said.

Although penalties have increased in recent years, that must be coupled with "some way to guarantee that the generator can pay," Macey said.

ISO-NE is in the middle of a multiyear process of revising its capacity market rules to better align procurements with tangible reliability benefits. The RTO also has an ongoing *project* "to reduce collateral shortfalls for Pay-for-Performance penalties that generators are assessed if they fail to operate or underperform during long-duration capacity-scarcity conditions."

Regarding transmission, Macey argued that a lack of oversight over line upgrades has led to high-cost projects that do not address the looming needs associated with the clean energy transition.

Asset-condition project costs have increased dramatically over the past 10 years, prompting states to push for changes. In response, transmission owners have rolled out some changes to the asset-condition review process, including a new database, process guide and opportunities for stakeholders to provide comment on projects in the planning stages. (See "Asset Condition Project Updates," *ISO-NE PAC Briefs: Dec. 20, 2023*.)

However, asset-condition costs have continued to accumulate. In mid-May, National Grid proposed an approximately $500 million project to replace degrading wooden structures with steel poles on a line that was previously refurbished in 2008. (See *ISO-NE Planning Advisory Committee Briefs: May 15, 2024*.)

Since the financial risk of these transmission investments falls on ratepayers, TOs face minimal consequences for ineffective or poorly planned upgrades, Macey said.

One NEPOOL officer took exception to Macey's characterizations of market and governance bias.

"When you look at NEPOOL, all the voting is transparent," said Dave Cavanaugh, vice chair of the organization's Participants Committee, whose meetings are closed to the press and public. NEPOOL's primary role as a purely advisory body limits the power of individual companies or sectors, he argued.

Regarding Macey's criticism of the capacity market, Cavanaugh said ISO-NE is working to address some of the issues the professor talked about, including increasing penalties. "There's a message in the marketplace that you need to perform."

Demand Response

Henry Yoshimura, director of demand resource strategy at ISO-NE, *outlined* the role of demand response in the clean energy transition.

As intermittent renewable resources increase, the grid will face "big periods of undergeneration and big periods of over-generation," Yoshimura said. These swings will lead to energy prices that increasingly "bounce around."

This variability of supply, combined with rapidly increasing peak loads, will make DR a key resource in the coming years, Yoshimura said.

"I do think that retail rate reform is needed in order to encourage demand flexibility," Yoshimura said, adding that time-of-use rates could incentivize end users to better align their consumption with wholesale prices.

Yoshimura noted that the proposed shift to a prompt and seasonal capacity auction could boost DR resources, which can be relatively quick to develop and could be used to fill capacity deficiencies on a shorter notice than many traditional transmission or generation solutions. ■

Joshua Macey of the University of Chicago Law School takes questions from audience members | *ISO-NE*

ISO-NE News

Stakeholders Support ISO-NE Long-term Tx Planning Filing, with Caveats

By Jon Lamson

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Stakeholder groups submitted comments to FERC last week in support of ISO-NE's proposal to create a new longer-term transmission planning (LTTP) process to facilitate more forward-looking transmission investments to meet looming needs (ER24-1978).

The new process was developed with the New England States Committee on Electricity (NESCOE) and features a default cost allocation method in which costs can be regionalized if the project is expected to bring net benefits.

LTTP requests for proposals would be issued by ISO-NE at the request of NESCOE, and the RTO would evaluate and select a preferred solution. States could then submit an alternative cost allocation method or decide to terminate the process. (See *NEPOOL TC Approves Process for States' Transmission Needs*.)

The proposal also includes a *supplemental process* for projects that do not pass the cost-benefit threshold; individual states could agree to cover the costs in excess, while the remaining costs would be regionalized.

ISO-NE filed the proposal with FERC prior to the commission's Order 1920, which requires transmission providers to plan at least 20 years into the future, evaluate solutions with a set list of criteria and establish a default cost allocation method to apply if states are unable to reach an agreement on cost. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.) The commission issued the order May 13; it goes into effect 60 days after its publication in the *Federal Register*; and compliance filings are due 10 months after that.

Advanced Energy United, NESCOE, RENEW Northeast, a coalition of climate nonprofits and the Connecticut Municipal Electric Energy Cooperative (CMEEC) all submitted comments in support of ISO-NE's proposal, applauding the agreement as an important step in proactive transmission planning.

United wrote that the proposal is "urgently needed," noting that "the first Order No. 1920-compliant planning cycle will not start for at least two years, with selection of transmission facilities slated to occur three years after that."

However, the clean energy trade association expressed concern that the proposal "fails to fully leverage the benefits of transmission competition" by tilting the playing field in favor of incumbent utilities.

"The proposal makes it very difficult for non-incumbents to offer any solutions that require new equipment on a PTO's [participating transmission owner's] existing transmission system," United wrote.

Nonincumbent transmission owners "are prohibited from identifying or installing new equipment needed for upgrades on existing lines without partnering with the incumbent PTO," the organization added.

These concerns were echoed in comments by RENEW and a joint filing by New Hampshire Transmission and LS Power. The latter two argued that the proposal makes the same mistakes as an RFP issued by ISO-NE in 2019 to address reliability concerns associated with the retirement of the Mystic Generating Station. Most of the submissions were disqualified for relying on the land of incumbent transmission owners, which ultimately led to tariff changes intended to fix the issue, the companies said (*ER22-733*).

"Under the limitations included in the proposal, only an incumbent transmission owner will be permitted to submit comprehensive solutions to identified needs," the companies wrote, adding that the proposal contains a "a *de facto* [right of first refusal] for incumbent PTOs."

RENEW urged FERC to accept the filing as is but called on ISO-NE to initiate an additional phase of revisions to address the concerns about incumbents.

In testimony submitted with its filing, ISO-NE said requiring complete solutions would increase "the likelihood of the process successfully leading to development of transmission solutions, rather than having the process terminate because the submitted longer-term proposals cannot be combined in a manner that addresses the identified needs."

CMEEC supported the proposal, calling it "a meaningful step towards the more comprehensive planning approach envisioned by the commission."

"The selection of projects through competitive solicitation should allow for consideration of transmission solution proposals that feature joint ownership arrangements with consumer-owned utilities," which could provide "myriad benefits" including financial benefits for ratepayers, tax exemptions, lower cost of debt and reduced siting risk, CMEEC wrote. ■

ISO-NE News

Clean Energy Groups Respond to ISO-NE Order 2023 Filing

Associations Praise Amendments to Plan, While Energy Providers Call for More

By Jon Lamson

ISO-NE's Order 2023 compliance filing received mixed comments from a range of clean energy stakeholders last week, drawing support from several large trade associations along with protests from multiple companies.

Order 2023 is intended to reduce wait times and costs associated with interconnection by mandating that transmission providers implement first-ready, first-served cluster study processes with defined timelines. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

ISO-NE filed its compliance proposal for Order 2023 and Order 2023-A on May 14 with the unanimous support of NEPOOL (*ER24-2007*, *ER24-2009*). (See *NEPOOL Participants Committee Briefs: May 3, 2024* and *NEPOOL PC Backs ISO-NE Tariff Revisions for Order 2023 Compliance*.)

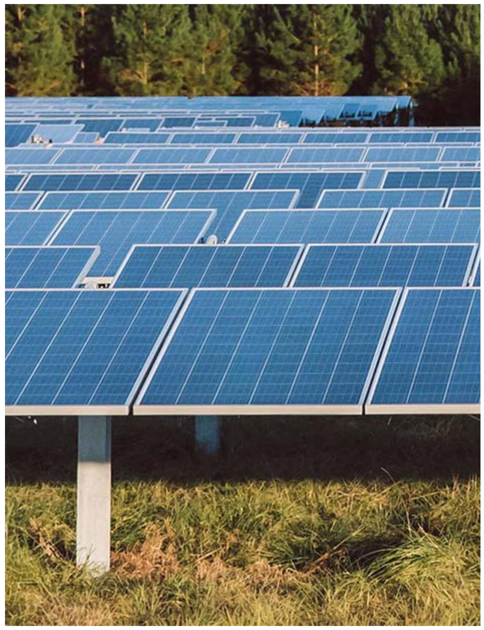
In comments supporting ISO-NE's filing, Advanced Energy United, American Clean Power Association, Natural Resources Defense Council and Solar Energy Industries Association jointly praised the RTO's adoption of several stakeholder amendments to its proposal.

"Throughout this process and right up to the final vote, there was extremely robust stakeholder engagement in the compliance proceeding," the groups wrote. "Ultimately, from more than two dozen stakeholder amendments, ISO-NE adopted four priority stakeholder proposals identified by parties representing interconnection customers in part or in full in some form.

"While future reforms beyond Order No. 2023 will be needed to ensure a fully functional and efficient interconnection process in New England, ISO-NE's Order No. 2023 reforms will mark an important first step in improving existing processes," the groups added.

ISO-NE has committed to continuing work to improve interconnection, writing in its filing that it "will continue its engagement with stakeholders both to ensure successful implementation at the outset and to assess potential improvements going forward."

The clean energy groups expressed interest in additional efforts to further reduce the overall cluster study timeline, provide more information and process transparency to interconnection customers and add flexibility to alter projects during the interconnection process to limit costs.



| EDP Renewables

RENEW Northeast also supported the filing, specifically applauding ISO-NE's proposal for studying storage resources.

Order 2023 directs RTOs to let storage developers dictate the system load at which they would charge, while requiring control technologies to prevent charging beyond this load. ISO-NE has proposed a variation in which it would study storage resources at "peak shoulder load" and rely on security-constrained economic dispatch to prevent storage "from being dispatched at load levels higher than the peak shoulder load under which the facility was studied."

RENEW Northeast wrote that the approach "will afford energy storage the flexibility to optimize its operations according to real-time grid reliability conditions rather than under limits established during the interconnection study process that will likely become less relevant over time as the grid topography changes."

Calls for Shorter Study Timelines, Expanded Use of Surety Bonds

New Leaf Energy also applauded the proposed storage methodology, along with ISO-NE's proposal to continue work on late-stage interconnection studies that are projected to be complete by the end of August.

The company echoed the need for additional work to improve interconnection in the region, writing that "the success of the new interconnection process relies, in part, on the timely evaluation of how the new process is working and continuous improvement thereof."

It recommended that ISO-NE establish an interconnection working group as a formalized setting to continue working on interconnection improvements.

Meanwhile, BlueWave called on FERC to require ISO-NE to follow the original timelines proposed in the order and increase the flexibility for interconnection customers to make changes to their request amid the interconnection process.

While Order 2023 puts a 150-day deadline on each cluster study and an additional 150-day deadline on cluster restudies, ISO-NE has proposed a 270-day deadline for cluster studies and a 90-day deadline for restudies.

"Protracted study timelines are one of the reasons for increased project costs and failures," BlueWave wrote. "Short study timelines would also result in less queue backlog, fewer restudies and fewer requests for modifications."

Longroad Energy argued that ISO-NE should expand the eligibility of surety bonds to meet the financial requirements within the interconnection process. ISO-NE has proposed to accept surety bonds only for commercial readiness deposit beginning in 2025.

"Surety bonds are generally easier and less expensive to procure than other accepted forms of financial security," the renewable developer wrote, adding that CAISO "already accepts surety bonds for generator interconnection customers."

Glenvale Solar took issue with the RTO's proposed variation regarding study deposits and application fees, writing that ISO-NE's proposal of uniform study deposits and application fees is "unduly burdensome and discriminatory to developers of smaller resources."

The company called on FERC to require the RTO to follow the tiered approach outlined in Order 2023. ■

MISO News

MISO: New Interconnection Queue Cycle to Wait on MW Cap Filing

By Amanda Durish Cook

MISO said new queue entries must wait while it takes another swing at imposing an annual megawatt cap on its interconnection queue.

MISO Manager of Generation Interconnection Ryan Westphal said the RTO will file by the end of the year for a cap to create a leaner and less backlogged waiting room for new generation. He said it won't accept applications for new generation projects until it hears from FERC on the filing. That likely will leave MISO a year behind on its queue processing.

"Our plan right now would be to get this through before we open another queue," Westphal told stakeholders during an Interconnection Process Working Group teleconference June 4.

Months ago, MISO staff hoped the RTO could begin processing *both* the 2023 and 2024 cycles of queue applications before the end of the year. That no longer appears to be the case. When asked by stakeholders, Westphal wouldn't venture an estimate as to how long before MISO would begin study work on the 2024 cycle of interconnection requests.

MISO's 2023 class of queue applications was delayed into early 2024 while it tried for new rules to discourage speculative projects from entering the queue. Those rules included its unsuccessful first attempt at a megawatt cap. (See *MISO Reports 123-GW Roster for 2023 Interconnection Queue Cycle*.) In April, MISO reported a 2023 queue intake of 123 GW spread across about 600 interconnection requests, substantially lower than 2022's 171 GW of proposed generation projects across 956 interconnect requests.

FERC late last year denied MISO's proposal to cap generation projects entering its interconnection queue on concerns over too many cap exemptions, the formula to establish the cap and potential resource adequacy deficits from limiting new generation onto the grid. However, FERC said a "cap in some form could be beneficial." (See *FERC Rejects MW Cap, Approves MISO's Other Stricter Interconnection Queue Rules*.)

MISO maintains that some limit on projects remains necessary. It said too many applications result in an overwhelming study process and make it nearly impossible to resolve models for a hypothetical system loaded with new generation.

"We did get a 30% reduction in the 2023 cycle versus 2022, but we still think we need to cap annual cycles. … We think this is necessary for the future to maintain an orderly queue going forward," Westphal said. "Ultimately, we want to have a queue that's fast and efficient where [we're] giving you good information so you can make better decisions. That's the hope, and we think that's achievable with less volume."

Westphal said that, MISO this year encountered the volumes it experienced in 2022, the queue could be as high as 350 GW by now. He emphasized that MISO's peak load expectation is 127 GW.

Construction of a Michigan solar farm for Consumers Energy | *National Grid Renewables*

Westphal said MISO is leaning toward simplifying the calculation, which could be as "simple as a percentage of load." He said MISO staff are at the same time contemplating ways to "limit the use of exemptions" to the cap to better the chances of it passing FERC's judgment.

Finally, Westphal reassured stakeholders that MISO is thinking about its future resource adequacy needs alongside its second attempt at a cap design. He said MISO envisions that a cap would put it in position to administer less onerous studies more quickly and deliver more interconnection approvals sooner.

Curb 'Queue Crashing,' Savion Advises

However, Derek Sunderman, of Shell subsidiary Savion, said that instead of a hard megawatt cap, MISO should pursue a "gating mechanism" to deter disproportionate applications from a handful of interconnection customers.

He said some interconnection customers will "queue crash," or submit large volumes of interconnection requests into a study application window to secure grid hookups.

Sunderman said MISO should consider administering a *volumetric price escalation* in the queue, where interconnection customers' fees and penalties rise as they submit more projects for study. He said higher milestone fees for 4 GW worth of applications versus 1 GW of submittals would allow smaller interconnection customers to meaningfully participate in the queue while still allowing larger interconnection customers to submit as many projects as they believe feasible. He also said escalating prices would cause large corporations to rethink their projects' viability.

Sunderman said if MISO pursues a hard cap at a hypothetical 80 GW, it might encourage a mad dash among developers to snap up queue positions. Volumetric price escalation, on the other hand, would allow all kinds of developers access, he said.

"It's not a fight of the fittest of who can consume the most megawatts first," Sunderman explained. "We're concerned that the higher-equipped companies could control a percentage of the queue" under a hard cap.

Westphal said MISO would consider Savion's proposal and hold more discussion on a cap design at the Interconnection Process Working Group's meeting July 23. ■

MISO News

MTEP 24 up to $5.8B; SREA Asks for Alternative to Entergy Reliability Project

By Amanda Durish Cook

The cost of MISO's 2024 Transmission Expansion Plan (MTEP 24) increased slightly to $5.8 billion, RTO planners said at a midyear checkpoint of the annual transmission planning cycle.

The preliminary MTEP 24 clocks in at 471 projects, stakeholders learned during a series of subregional planning meetings June 3-7. An earlier estimate pinned the MTEP 24 package at $5.5 billion. MISO has said this year's MTEP marks a return to normal levels of investment following last year's record-breaking $9 billion *package*. (See *Early MTEP 24 Designates $5.5B in Transmission Spending*.)

MTEP 24 includes $688 million in generator interconnection projects and $952 million in baseline reliability projects. Everything else is designated by MISO as "other" and includes projects to address age and condition of facilities, accommodate load growth or meet transmission owners' self-imposed reliability criteria.

During a June 6 East Subregional Planning teleconference, MISO's Amanda Schiro said the bulk of MTEP 24's other project proposals are motivated by load growth and the age and condition of infrastructure.

Schiro said MISO will continue to test projects for alternatives through the summer and share a preview and draft report of MTEP in September. She told stakeholders MISO is no longer accepting ideas for alternative projects.

Return of Hartburg-Sabine Junction?

Again this year, MISO South contains a big-ticket baseline reliability project that has a clean energy group requesting an analysis of alternatives.

Entergy Texas proposed a new 35-mile, 500-kV line and substation in East Texas at $409 million. The utility said the line would help prevent potential thermal overloading of "many" 230-kV lines that supply the Port Arthur area. MISO said Texas accounts for 42% of MISO South costs for MTEP 24 because of the large project.

Last year, Entergy Louisiana proposed nearly $2 billion alone in a baseline reliability project to alleviate its Amite South load pocket; MISO ended up *recommending* an alternate solution to portions of the project.

The Southern Renewable Energy Association (SREA) has asked that MISO explore resurrecting its $134 million, 500-kV Hartburg-Sabine Junction project in East Texas in place of Entergy Texas' reliability project.

MISO canceled the development of the market efficiency project in 2022 after Texas enacted a right-of-first-refusal law that delayed construction and Entergy built gas-fired plants in the area that made the line less beneficial. Attempts by transmission developers and clean energy groups to save the project have thus far failed. (See *FERC Rejects Last-ditch Effort to Save Tx Project*.)

SREA said that because Hartburg-Sabine was proposed to connect to some of the same infrastructure as the new reliability project, it may be able to pull double duty to alleviate reliability problems in East Texas while providing economic value. However, SREA doesn't know if the market efficiency project can solve the same contingencies.

At the South Subregional Planning meeting June 7, MISO South Expansion Planning Manager Trevor Armstrong said MISO will study the potential for Hartburg-Sabine and present results of its analysis in September.

Entergy Texas did not respond to *RTO Insider*'s request for comment on whether it thinks Hartburg-Sabine might be a suitable substitution.

Additionally, Entergy Texas last week *announced* it is seeking permission with the Public Utility Commission of Texas to spend more than $2.2 billion to build two new gas-fired power plants near Entergy's line proposal — one in Port Arthur and another about 45 miles north of Houston. The utility said both plants would feature hydrogen-capable combustion turbines and one could be equipped for carbon capture.

Entergy said it needs the plants online in 2028 to accommodate "extraordinary economic and population growth."

SREA Transmission Director Andy Kowalczyk said the association believes Entergy Texas must pursue the new plants because it hasn't addressed its load pockets with meaningful transmission.

"Our general stance is that we believe these sorts of procurements will continue to happen until Entergy addresses the load pockets with increased import capability that provides access to more capacity and market options," he said in a statement to *RTO Insider*.

He said Entergy had identified the the East Texas, West of the Atchafalaya, Amite South and Downstream of Gypsy load pockets as issues as far back as 2005. He said that while other Entergy companies focused on Amite South and Downstream of Gypsy with transmission projects in MTEP last year, the focus on alleviating load pockets doesn't appear to have extended to Entergy Texas.

How MISO can plan for load growth has become a point of focus for some stakeholders.

At the Planning Advisory Committee's meeting May 29, Environmental sector requested that the RTO modify its annual transmission expansion planning and generator interconnection study procedures "to accommodate new, large lumpy loads like data centers and manufacturing." ■

Entergy Texas' Veteran Substation | *Entergy*

MISO News

FERC Sets Dynegy's MISO Market Manipulation Case for Hearing

By Amanda Durish Cook

Nearly a decade after the MISO capacity auction in which Dynegy was found to have manipulated clearing prices, FERC has directed hearing and settlement procedures in the case (*EL15-70, et al.*).

The commission's June 6 order initiated a hearing to resolve the issue while denying Dynegy's request for oral argument before FERC. The commission had been considering briefs from Dynegy and complainants Public Citizen and the Illinois Office of the Attorney General on whether Dynegy should refund $429 million to Illinois ratepayers.

Two years ago, FERC concluded that Dynegy knowingly manipulated the 2015/16 Planning Resource Auction to produce Southern Illinois' Zone 4 clearing price of $150/MW-day. FERC's arrival at that conclusion followed a twisty course, including an abruptly closed nonpublic investigation, an initial finding that cleared Dynegy with little explanation, a remand from the D.C. Circuit Court of Appeals and an announcement that the commission would revisit its decision. (See *FERC Staff Finds Dynegy Manipulated 2015 MISO Capacity Auction*.)

In its briefs, Dynegy maintained the process unfurled unjustly, saying FERC's order on remand "reflects bad policy, is fundamentally unfair and is inconsistent with existing norms." It said the commission improperly raised questions about the "finality" of its decision to close the investigation while "importing" nonpublic information gathered in an investigation under Federal Power Act Section 222 into a public proceeding under Section 206.

The Coffeen Power Station, once part of Dynegy's Southern Illinois fleet, closed in 2019 | *Dynegy*

"According to Dynegy, this departure from policy, this departure from policy 'threatens public confidence in the integrity of [FERC's] enforcement process' and 'negatively affect[s] the perceived fairness of commission investigations,'" the commission said.

Dynegy also argued its due process was violated because the commission's Office of Enforcement had to file a remand report outlining allegations in a Section 206 proceeding using evidence from its closed, nonpublic investigation. Because of the nonpublic nature of the investigation, Dynegy said it couldn't participate in discovery or cross-examination.

It claimed the remand order exceeded FERC's authority because, according to the commission itself, a Section 206 filing isn't the "proper vehicle to prosecute claims of market manipulation."

The Illinois AG and Public Citizen fired back that "Dynegy cannot now claim, at this late stage of the proceeding, and at the risk of further delay, that its procedural rights have been violated due to the absence of an evidentiary hearing that it never requested."

FERC said its actions were "an appropriate response" to the D.C. Circuit's findings, were consistent with its precedent and do not rise to violations of due process.

"We acknowledge that this case, and the issues that the commission must address on remand, present complicated questions regarding the interplay of the closed FPA Section 222 investigation and resolution of the still-pending FPA Section 206 complaints," FERC said. It added that it takes seriously its decisions to disclose nonpublic information from its investigations and doesn't foresee itself regularly releasing such information in the future.

"However, we continue to conclude that submission of the remand report and the opportunity for parties to submit initial and reply briefs was an appropriate response," the commission said.

FERC also pointed out that it's allowed to release nonpublic information from an investigation and that it's common practice for it to initiate further briefings following a remand, "particularly where an appellate court rules that the commission failed to adequately explain its decision."

Dynegy also argued that it wasn't made aware via Enforcement staff that its behavior leading up to and during the 2015/16 auction could constitute market manipulation. It said it didn't have a legal or regulatory requirement to sell capacity, nor was it "on notice" that FERC expected it to do so.

The commission didn't buy the second argument from Dynegy and ruled the company had "adequate notice that its behavior could constitute market manipulation under relevant commission regulations and precedent."

FERC pointed out that Enforcement staff said in their in briefs that Dynegy took pains ahead of the auction to increase the chance an offer from it would set the clearing price in Zone 4. Staff said Dynegy "engaged in a scheme to amass and hoard megawatts that might otherwise have been offered into the 2015/16 auction at a zero price, thereby increasing the likelihood that a non-zero-priced Dynegy resource would be the marginal resource and set the Zone 4 clearing price."

The division said evidence pointed to Dynegy expecting that the 2015/16 auction would clear below its lowest non-zero offer of $108/MW-day. Rather than submit all its supply at the cost-based $108 price, Dynegy engaged in pre-auction sales at approximately $66/MW-day until it offloaded enough supply to create a specific gap and therefore ensure its own resource would set the clearing price in the zone.

Staff said Dynegy then took steps to maintain the gap by increasing the price of the capacity component of its retail sales offers from $66/MW-day to $164/MW-day, resulting in 125.4 MW of unsold capacity, and refusing to offer a price to two customers for 385 MW of capacity.

"Dynegy also sought to increase the 'gap' by purchasing 50 MW of capacity for $61/MW-day — an act that made no economic sense given that it already held thousands of megawatts of unsold capacity," Enforcement staff wrote.

The company claims its actions were "motivated by a legitimate intent to recover its costs," not to commit fraud. It said after it lost money in the 2013/14 auction, it devised a strategy to recover its costs by offering capacity both prior to and in auctions. Dynegy said its attempts to receive price signals that could help it make decisions, including resource retirement, were "not only economically rational, but the only way for an independent power producer, reliant on market revenues, to stay in business." ■

MISO News

FERC OKs MISO Settlement Rules for Widespread Tx Outages

By Amanda Durish Cook

FERC on May 31 ruled MISO can apply new settlement practices to generators physically disconnected from the grid during extensive transmission outages triggered by extreme events.

The commission's order allows MISO to adjust settlements when extreme events cause significant forced transmission outages that sever generation from the grid. Under the change, the RTO now can reflect in settlements the involuntary nature of a disconnection through a "forced-off asset" designation and block generators from excessive penalties or payments (*ER24-1191*).

The revisions went into effect June 3. MISO sought FERC's approval for the rules before the RTO's South region enters the Atlantic hurricane season.

MISO's scarcity pricing setup assumes lines are intact and operational, with market participants having physical capability to respond to price signals by reducing demand or ratcheting up supply.

However, MISO said the "always connected" assumption doesn't reflect the reality of cases like Hurricane Laura, when parts of the transmission system were destroyed. In those cases, the RTO said it's "inappropriate and inequitable" to levy performance penalties on disconnected generators unable to meet their day-ahead commitments by forcing them to "buy back their day-ahead committed energy at dramatically higher real-time prices."

On the other hand, MISO said it's equally unfair to "compensate involuntarily disconnected load as if it responded to real-time scarcity pricing and then pass off the cost of such windfall compensation to other market participants through uplift."

MISO plans to use its day-ahead LMPs prior to the event to retroactively settle excessive penalties or excessive windfalls for knocked-off assets.

FERC agreed MISO's plan will mitigate "substantial financial impacts without any corresponding operational benefits" in circumstances when multiple transmission outages prevent market participants from responding to price signals.

"We find that the proposed revisions would provide MISO with reasonable discretion to mitigate the unintended consequences of scarcity pricing during extreme events by evaluating individual facts and circumstances," the commission added.

MISO said the revisions won't apply during emergencies when the transmission system remains intact. It will require at least 10 transmission outages and a 10% increase in dead or disconnected pricing nodes before conditions are met to use the forced-off designation. It also pledged to declare forced-off asset events no more than two weeks after they occur.

If necessary, MISO will adjust settlements for resources in the path of the event that were cleared in the day-ahead market but couldn't inject for at least six dispatch intervals. It will also make adjustments for load zones in the area with fully or partly forced-off loads and to virtual transactions associated with pricing nodes in the area that cleared in the day-ahead market.

MISO adviser Chuck Hansen has said events need to be "widescale" to activate the knocked-off designation, such as a weather disaster, geomagnetic event or cyberattack. The RTO expects such events will be rare. The status would not apply to assets that respond to MISO-directed load shedding.

The settlement rule change is part of MISO's ongoing effort to improve its scarcity pricing. ■

Damage to Entergy's transmission system as a result of Hurricane Laura in 2020 | *Entergy*

PJM News

PJM OC Briefs

PJM Presents Black Start Manual Revisions

PJM *presented* the Operating Committee last week with a set of revisions to Manual 12 regarding fuel assurance requirements for black start resources.

The RTO said the language approved June 6 was included in the package the OC advanced two years ago but was inadvertently excluded from manual revisions approved by the Markets and Reliability Committee in November 2022. (See "Black Start Fuel Requirements Advance to Members Committee," *PJM MRC Briefs: Oct. 24, 2022*.)

The effort established a new category of "fuel-assured" generators and required at least one such unit to be committed in each transmission zone. The criteria to qualify as a fuel-assured unit vary based on resource type, including connections to multiple interstate gas pipelines, on-site fuel storage and dual-fuel capability.

The latest manual revisions create an exception to allow fuel-assured black start resources to avoid penalties if they fall below mandated consumable storage levels because they responded to a performance assessment interval (PAI) or if the storage vessels were taken out of service for regulatory inspections.

The changes also remove a fuel assurance notification requirement from Manual 12 and replace it with a stipulation that generators must provide verification that they have adequate fuel and consumables upon PJM request, along with an annual verification requirement in the black start test form.

The language is set to go before the OC for an endorsement vote July 11 and the MRC on July 24.

PJM Details Temporary Exception Submission Process

PJM's Lauren Strella Wahba *presented* the process for market participants to submit temporary exceptions in Markets Gateway once software updates go live Aug. 1.

The "Daily" and "Real Time Temp Except" fields have been used as an interim solution since FERC approved PJM's real-time temporary exception design last November. (See "Stakeholders Endorse Real-time Temporary Exception Manual Revisions," *PJM MIC Briefs: Feb. 7, 2024*.)

Rather than submitting supporting documentation to PJM by email, the "Exception" page of Markets Gateway will have buttons for uploading documents, though the email option will remain as a fallback.

Market participants withdrawing an active temporary exception will be required to first restore their cost-based and price parameter-limited schedules.

PJM Reviews May Operating Metrics

Inaccurate weather forecasting caused several days of high load forecast error in May, PJM's Marcus Smith *told* the OC. Conditions were warmer than expected between May 16 and 21, which follows a trend of load forecasts becoming highly sensitive to numerous variables when temperatures are around 70 degrees Fahrenheit.

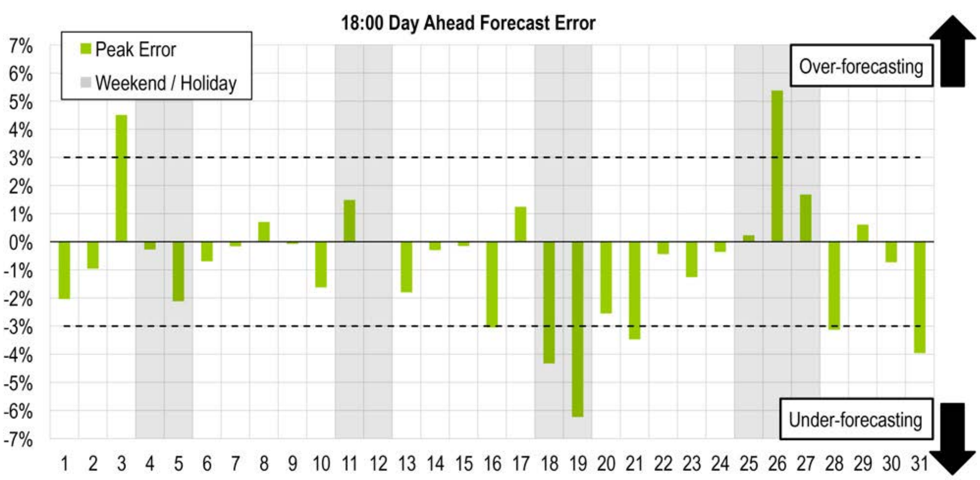
The May average hourly forecast error was 1.51%, with an average peak error of 1.81%, falling near the 25-month average for both figures.

The month saw one shared reserve event, a high system voltage action, a geomagnetic disturbance (GMD) action and 20 post-contingency local load relief warnings (PCLLRWs).

PJM's Kevin Hatch *said* the GMD action was in effect May 10 and 11 after two transformers were in violation for 10 minutes. Geomagnetically induced current (GIC) was seen on multiple transformers, and two reactive control devices tripped offline.

While increased geomagnetic activity was seen for a week after May 10, Hatch said the action was not needed for the entirety of the period and the grid experienced no major impacts. ■

— Devin Leith-Yessian



PJM presented the daily peak forecast error for May 2024 to the Operating Committee.| *PJM*

PJM News

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Endorse Revisions to CIR Transfer Issue Charge

VALLEY FORGE, Pa. — The PJM Planning Committee last week endorsed revising an *issue charge* focused on how capacity interconnection rights (CIRs) may be transferred from a deactivating generator to a new resource.

The issue charge seeks to solve the misalignment between the transfer process, which is tied to phases of the interconnection queue, and recent changes to the interconnection process. (See "Stakeholders Discuss Change to CIR Transfer Issue Charge," *PJM PC/TEAC Briefs: April 30, 2024*.)

The endorsed change rewrites the out-of-scope language to prohibit changes to the process for transferring CIRs to replacement resources interconnecting to the same substation as the deactivating generator but at a different voltage level. It previously prohibited changes for when the replacement located at a different point of interconnection.

The revisions also shift the working group from the Interconnection Process Subcommittee to the PC to accommodate the wider scope. The issue charge was cosponsored by East Kentucky Power Cooperative and Elevate Renewables.

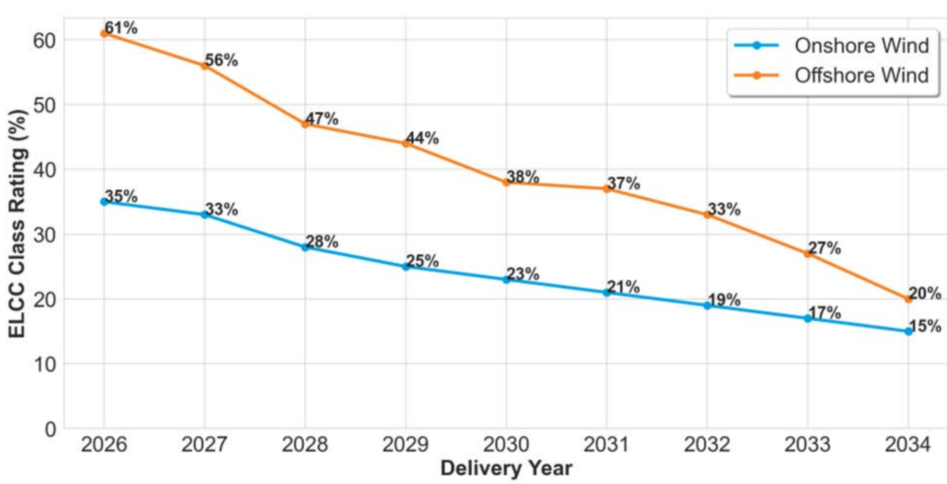
CIFP Manual Revisions Endorsed

Stakeholders endorsed a slate of *manual revisions* codifying PJM's new approach to risk modeling and accreditation drafted through the Critical Issue Fast Path (CIFP) process last year and approved by FERC in January. (See "First Read on CIFP Manual Revisions," *PJM PC/TEAC Briefs: April 30, 2024*.)

Patricio Rocha Garrido, PJM | © *RTO Insider LLC*

The changes include how PJM will use its marginal effective load-carrying capability (ELCC) framework for accrediting all generation resources, the simulation of resource outputs and the definition of the capacity emergency transfer objective (CETO), which sets the import capability needs to meet reliability objectives. The revisions also include several calculations used in accreditation and for setting capacity procurement targets through the Reserve Requirement Study (RRS).

Manuals 20, 21 and 21A would be replaced with Manuals 20A and 21B beginning with the 2025/26 delivery year, while Manual 14B would remain with language changes. The Markets and Reliability Committee is set to consider endorsement of changes on June 27 alongside a rewrite of Manual 18 to effectuate changes on the markets side. (See "Stakeholders Endorse Manual Revisions to Implement CIFP Changes to Capacity Market," *PJM MIC Briefs: May 1, 2024*.)



PJM presented preliminary effective load-carrying capability (ELCC) ratings for several capacity resource classes, which showed wind ratings decreasing through 2034. | PJM

Preliminary ELCC Class Ratings

PJM *presented* a preliminary set of ELCC class *ratings* projected through the 2034/35 delivery year that show declining values for renewable and storage resources and fairly stable or increasing ratings for fossil generation.

Offshore wind is hit particularly hard, with its class rating expected to go from 61% in 2026 to 20% in 2034. Onshore wind is projected to fall from 35% to 15%.

PJM's Patricio Rocha Garrido said the decline in wind generation ratings was driven largely by the hours of risk being increasingly concentrated on days when wind performance is projected to be low. Much of that data is derived from the 2014 polar vortex on Jan. 7 and 8, as well as low performance hours on Dec. 26, 2022, during Winter Storm Elliott.

As the amount of wind generation on the grid increases, Rocha Garrido said, the resource class is able to meet the need on a wider number of days. That in turn concentrates the risk that remains onto winter days with low wind performance.

Solar ratings are similarly being driven down by increased winter risk matching up poorly with times of peak solar availability. Tracking solar has a rating of 11% in 2026 dropping, to 4% in 2034, while fixed solar falls from 7% to 3%.

The longer duration of winter events was also a factor for declining ratings of shorter-term storage resources. Four-hour storage falls from 56% to 38% over the years analyzed, while six-, eight- and 10-hour storage see less significant drops.

While both coal and nuclear generation saw modest declines in their ELCC ratings, gas-fired resources saw upticks owing to risk patterns swaying toward days when they have stronger performance. Combustion turbines fared particularly well, increasing from 61% to 78%.

PJM spokesperson Jeff Shields said the

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increased gas generation ratings are from both increased winter performance since the 2014 polar vortex and the pattern of risk shifting to days when other resources do not perform as well.

"The gas CT ratings increase because the risk shifts to winter days with poor wind performance in which the gas CT performance is not as low as during days such as the first polar vortex. Therefore, you can argue that the increase is driven by risk shifts that are caused by better gas CT performance, and other resources — wind, in particular — performing worse," he said.

Rocha Garrido said the assumptions for the projections included using the 2025/26 delivery year assumed resource portfolio as a basepoint and modeling retirements and new entry using a vendor forecast. That includes growth in the wind, solar, four-hour storage and solar-storage hybrid classes, as well as coal generation deactivations.

PJM Pushes Pause on LTRTP to Focus on 1920

PJM *plans* to hold off on advancing its long-term regional transmission planning (LTRTP) proposal and shift its focus to its compliance filing for FERC Order 1920, which requires RTOs to develop scenario-based planning processes on a 20-year horizon. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

The PC endorsed the LTRTP approach in March, but deliberations were deferred at the MRC in April to see how it measured up against the commission's long-awaited order. (See "Stakeholders Defer Vote on Long-term Planning Proposal," *PJM MRC Briefs: April 25, 2024*.)

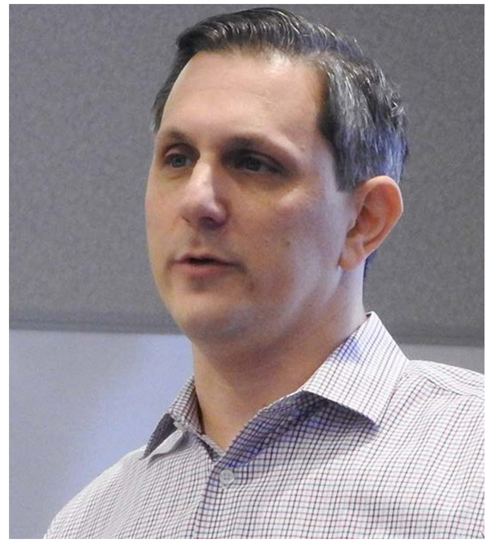
PJM's Jason Connell laid out several differences between the LTRTP design developed over the past year and Order 1920's requirements, which include at least one extreme weather scenario, "plausible" and "diverse" scenarios, and a wider range of planning factors. While the LTRTP would implement a 15-year planning horizon, the order requires at least 20 years, and the two reliability and policy scenarios PJM proposed fall short of the minimum of three scenarios the commission required.

"There is quite a bit of deviation between what we proposed and the order," Connell said.

Presenting the Natural Resources Defense Council's *perspective* on the differences, Senior Advocate Tom Rutigliano said the first year of PJM's proposed LTRTP timeline involved building scenarios, work that could be done in parallel with preparing the compliance filing. Waiting until compliance is approved by FERC would likely result in delaying implementation until the fourth quarter of 2026. Laying some of the groundwork in scenario design ahead of time could shave a year off implementation and begin addressing PJM's long-term resource adequacy concerns faster, he argued.

"This needs to start sooner, so what we've got here is work that can be done in parallel," Rutigliano said.

Connell said PJM's goal is to move quickly and bring manual revisions to stakeholders within a few months detailing how it will initiate the assumptions phase of a larger long-term planning effort. The revisions may also include starting on the analysis phase as well while the compliance filing is prepared and pending at the commission.



Jason Connell, PJM | © *RTO Insider LLC*

Transmission Expansion Advisory Committee

NJ BPU Pausing 2nd SAA Competitive Window for Offshore Transmission

The New Jersey Board of Public Utilities has suspended the second State Agreement Approach (SAA) competitive transmission solicitation window, which PJM was planning to administer in July.

Ryann Reagan, wholesale market policy specialist for the BPU, *told* the Transmission Expansion Advisory Committee that the board's timeline no longer aligned with the 2024 Regional Transmission Expansion Plan (RTEP) cycle. The amount up in the air with regional transmission planning and offshore wind also contributed to the decision, she said, pointing to the board's work updating the state's Energy Master Plan and Offshore Wind Strategic Plan.

Reagan said it's hard to see where the state's offshore wind goals could align with PJM's planning processes until there is more clarity around the LTRTP and Order 1920.

The board intends to move forward with its fourth and fifth solicitations for offshore wind generation, with awards likely prior to the transmission planning being completed.

Deactivation Request Update

Two generators have filed for deactivation over the past month, PJM's Michael Herman *told* the TEAC.

J-Power USA Generation is seeking to bring nine gas-fired turbines in the ComEd zone offline in June 2025, while AES submitted a deactivation request for a 5-MW battery located at its Warrior Run cogeneration plant.

PJM is also in the process of studying a deactivation request for Cogentrix's Elgin generator, which has four gas turbines amounting to 483 MW. Reliability analysis is set to begin in the third quarter of this year, Herman said.

IEC Remains on Hold

PJM's Nick Dumitriu said the RTO's annual *re-evaluation* of market efficiency projects recommended leaving Transource Energy's Independence Energy Connection (IEC) project on suspension because of poor cost-benefit results and possible reliability violations. The PJM board voted to suspend the project on Sept. 22, 2021. (See "Transource Update," *PJM PC/TEAC Briefs: Oct. 5, 2021*.)

The two-pronged project seeks to alleviate congestion on the AP South Interface by constructing about 20 miles of lines between a new Furnace Run substation in York County, Pa., and Harford County, Md. The western portion would consist of a 230-kV double-circuit transmission line running 28.8 miles from Franklin County, Pa., into Washington County, Md.

Dumitriu said the project would reduce congestion on AP South by $84.97 million by 2033, along with reducing congestion by about $41 million on a series of other constraints, but a new $341.72 million constraint would be introduced on the 230-kV Ringgold-Frostown Junction line.

PJM's Tim Horger said an update on the proj-

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ect's future is planned for next month.

Supplemental Projects

American Electric Power *proposed* a $155.7 million project for a new service request to serve 1,100 MW of load in New Carlisle, Ind., expected to come online in December 2026.

The project would consist of two new 345-kV substations, Larrison Drive and New Prairie, cut into the Elderberry-Dumont and Dumont-Olive Bypass lines. End work would also be conducted on the Sorenson, Elderberry and Dumont substations.

PPL *presented* a new service request expected to interconnect 240 MW in 2026 and grow to 1,980 MW by 2033. The customer, located in Hazleton, Pa., would be served by a 230-kV source.

PECO Energy *presented* a $36 million project to rebuild its 6.24-mile, 230-kV Planebrook-Bradford line, which the utility said is nearing end of its life at 96 years old.

The utility also proposed a $17 million project to rebuild its nearly 100-year-old, 69-kV Tacony substation and install new equipment to upgrade it to 230 kV. Inspection of the site has found that equipment is in poor condition and cannot be repaired.

Duke Energy Ohio & Kentucky *proposed* a $7.8 million project to replace nine 345-kV oil-operated breakers at its Woodsdale substation because of maintenance issues. The project would install gas-filled circuit breakers, replace 17 switches and replace all bus conductor.

Duke also presented a new service request for a customer near Mount Orab, Ohio, seeking to interconnect 2,000 MW by 2029.

FirstEnergy *presented* a $9.8 million project to convert its 230-kV Milesburg substation, located in the APS zone, from a straight bus to a four-breaker ring bus. It said that maintaining the existing configuration elevates outage risks for 3,116 customers with 107.6 MW of load if the facility experiences a single stuck breaker contingency.

Dominion Energy *presented* several projects to interconnect data center load in Northern Virginia totaling $57 million.

A new 230-kV Sloan Drive substation would be built for $30 million, which includes constructing two 230-kV lines to the future Bermuda Hundred substation. The substation has an projected in-service date of Dec. 31, 2027, and would serve over 100 MW of data center load.

The utility proposed cutting into the 230-kV Techpark Place-White Oak line to build a new "Decoy Airfield" substation serving 100 MW of data center load. The new substation would cost an estimated $12 million to build with an in service date of Jan. 1, 2026. A $15 million project would tap the 230-kV ICI-Allied line to connect to the new Bermuda Hundred facility. ■

— Devin Leith-Yessian

Northeast news from our other channels

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PJM MIC Briefs

Additional Parameters for Demand Response Endorsed

VALLEY FORGE, Pa. — PJM's Market Implementation Committee endorsed by acclamation a *proposal* to add two energy market parameters for economic demand response. (See "First Read on Proposed Demand Response Energy Market Parameters," *PJM MIC Briefs: May 1, 2024.*)

The changes would allow DR providers to set a cap on how long they can be dispatched and a minimum interval before they can be committed again after being released from a previous dispatch.

FERC last July approved a PJM proposal to tighten performance assessment interval triggers, allowing pre-emergency demand response to be deployed without prompting a full capacity call for all resources. (See *FERC Approves PJM Change to Emergency Triggers*.)

PJM's Pete Langbein offered an amendment to the proposed Manual 11 revisions to state that energy market parameters cannot supersede a load management deployment in the capacity market, a stipulation he argued is already reflected in the status quo language.

Langbein gave the example of a DR resource that had been released from an energy market commitment and was in the middle of a minimum release time when it was called on for capacity. If that resource did not respond and followed its energy market parameter, it could be subject to Capacity Performance (CP) penalties and testing requirements.

PJM plans to ask the Markets and Reliability Committee for endorsement at its Aug. 21 meeting, followed by the Members Committee on Sept. 25 and a FERC filing in October. The filing would likely ask for a sixth-month implementation period.

PJM to Refile Portions of Rejected CIFP Proposal

PJM laid out its *plan* to refile several components of its Critical Issue Fast Path (CIFP) proposal rejected by FERC in February, which focused on the CP construct and market seller offer caps (MSOC). (See *FERC Rejects Changes to PJM Capacity Performance Penalties.*)

PJM's Walter Graf said the components selected for refiling were those that order rejecting the order either indicated support or did not touch on. For items where PJM received minimal feedback from the commission, Graf said PJM's future filing is likely to be fairly similar.


Walter Graf, PJM | *© RTO Insider LLC*

The proposal includes "clarifying revisions" to the definition of Capacity Performance quantified risk (CPQR), MSOC values for planned generation based on net cost of new entry (CONE), segmented offer caps, and a forward-looking energy and ancillary service (EAS) offset for offer caps and the minimum offer price rule (MOPR).

The proposal would allow generators that intend to participate in the energy market regardless of whether they clear in the capacity market to offer into Base Residual Auctions (BRAs) at least as high as their capacity performance quantified risk (CPQR) value.

In its October 2023 transmittal letter, PJM said allowing generators likely to remain in operation regardless of their position in the capacity market would avoid over-mitigating market sellers with a low or negative avoidable cost rate (ACR). The filing argued that the status quo market seller offer cap (MSOC) prevents some market sellers from fully representing their costs to deliver capacity — a dynamic it said could be leading some resources not subject to the must-offer requirement to avoid participating in the capacity market entirely.

PJM does not plan for the refiling to include many of the core changes addressed in its original filing, such as limiting bonus payments for generators that overperformed during emergency conditions to only committed capacity resources, excusing generators whose price-based offers exceeded their cost-based offers from CP penalties and third-party review of unit-specific MSOC proposals.

PJM is not including a process for calculating alternative offer caps if it determines that a market seller's proposed MSOC did not conform to the tariff as it awaits a FERC ruling on its rehearing request. The refiling will also exclude an element of PJM's original proposal to remove the physical penalty option for fixed resource requirement entities. The PJM Power Providers (P3) and Electric Power Supply Associated (EPSA) have jointly requested rehearing on that element of FERC's rejection of ER24-98.

PJM is not seeking to move forward with a standardized CPQR calculation because the specificity the commission sought would be difficult to uniformly produce across resource classes, Graf said. But he added that the calculation PJM proposed to use could be used by market sellers to aid in their own CPQR proposals.

Exelon's Alex Stern said he's glad PJM is reviewing the commission's rejection order be-

PJM News

cause the resource adequacy concerns which prompted the filing have only grown over the past year.

Energy Efficiency Proposals Deferred While Complaint Pending

PJM, its *Market Monitor* and *Affirmed Energy* all delayed presenting proposals to revise how the RTO measures and verifies (M&V) energy efficiency resources due to a complaint the Monitor filed last week asking FERC to deny capacity market payments to 10 EE providers. (See *PJM Monitor Alleges EE Resources Ineligible to Participate in PJM Capacity Market.*)

Aaron Breidenbaugh, of CPower, said he understood that the EE providers named in the complaint have been counseled to avoid discussing issues raised in the filing until the issue has been resolved. Because the filing argues that mid- and upstream EE programs have not met the Reliability Pricing Model (RPM) participation requirements, he said the complaint overlaps with the very issue before the MIC.

Affirmed Energy's Luke Fishback said the company withdrew its package from the June 5 agenda because it would be unproductive to engage with discussions about potential revisions to M&V requirements while the complaint about existing standards is pending.

Exelon's Alex Stern said the pending complaint can't help but "put a chilling effect on not only these stakeholder discussions but also EE generally."

PJM Associate Counsel Chen Lu said he thinks the complaint is limited to the validity of post-installation measurement and verification (PIMV) reports filed for the 2024/25 delivery year and therefore would not clash with discussion about future M&V design.

Marji Philips, of LS Power, rebuked PJM for a communication sent to EE market participants on May 31, which said the RTO will be delaying action on PIMV reports until the complaint has been resolved, effectively holding up all EE revenues in the process. She said the complaint is an allegation that must be substantiated before PJM can take action through a deficiency process in accordance with a FERC order.

"It's completely violative of any FERC procedure," she said. " … You don't take an action based on a filed complaint."

Responding to questions about the implications of the PIMV delay for EE providers, Lu said no payments are made and prospective market participants are not subject to deficiency charges until PJM has makes a determination on the reports. If the reports were rejected, he said, entities would be considered unavailable during the delivery year and subject to deficiency charges.

Langbein said PJM is reviewing the May 31 communication and plans to send out an update on how it intends to proceed with the PIMV reports and EE payments.

PJM Presents Revised CONE Values

The Brattle Group *presented* revised financial parameters used to calculate net CONE for the 2026/27 Base Residual Auction (BRA).

Net CONE is one of the inputs used for defining prices on the Variable Resource Requirement (VRR) curve. (See "Update Re-evaluation of CONE Inputs," *PJM MIC Briefs: May 1, 2024.*)

PJM in April proposed reviewing the financial inputs to net CONE to account for shifting market conditions since the 2022 Quadrennial Review. Increasing interest rates were among the major contributors, PJM's Skyler Marzewski said. The change is being pursued through the quick fix process, which allows an issue charge to be brought and voted on concurrent with a proposed solution.

"We're trying to make sure net CONE would be better aligned with the financial conditions that we're currently seeing," Marzewski said.

Brattle recommended increasing the after-tax weighted-average cost of capital (ATWACC) from the 8.85% used in the quadrennial review to 10%, which increases the cost to construct a combined cycle resource — currently the reference resource — by $15 to $18/kW-year. The cost of combustion turbines increased by $10 to $12/kW-year and battery electric storage systems by $18 to $20/kW-year.

Given market volatility, Brattle's Bin Zhou recommended adjusting the financial parameters for at least the next few auction cycles.

Responding to stakeholder questions about how the review was conducted, Brattle's Sam Newell said it relied on the same study approach as the quadrennial review.

Marzewski said Brattle is also considering whether PJM needs to reconsider the overall cost for a new resource, with preliminary analysis suggesting that there is no need at this time. Newell encouraged market participants to reach out to Brattle with any specific market information to assist its reevaluation of financial parameters or cost indexing. Increased turbine prices could be one such data point, he said.

Stakeholders Discuss Path Forward on Multi-Schedule Modeling

PJM intends to move forward with an alternative solution for selecting schedules in the market clearing engine (MCE) to facilitate its multi-schedule modeling design, which is expected to significantly increase computing times under the status quo schedule selection approach. (See "Stakeholders Endorse Multi-schedule Modeling Solution," *PJM MRC/MC Briefs: Dec. 20, 2023.*)

FERC in March rejected the multi-schedule modeling proposal endorsed by stakeholders in December 2023. That package would have introduced a formula to evaluate generators' offers and select one expected to produce the lowest total dispatch cost and forward only that offer to the MCE.

The commission rejected that proposal, citing the "crossing offer curves" scenario the Monitor raised, under which PJM's proposed formula would select market-based offer based on its dispatch cost at EcoMin even if it would be notably more expensive than a cost-based offer at higher outputs.

"PJM's proposal would largely eliminate market power mitigation in the day-ahead Energy Market by selecting for consideration in PJM's market clearing optimization software a single offer per resource solely on the lowest dispatch cost at EcoMin … it would no longer mitigate a seller's offer to the offer producing the lowest total production cost by considering the entire offer curve for each of a seller's offers," the commission wrote.

PJM's Keyur Patel *said* the RTO planned to advance the MIC proposal co-sponsored by PJM and the GT Power Group, which received the second-highest degree of support during an October 2023 vote. That proposal attempts to address the crossing curves issue by only selecting market-based offers when a resource passes the three pivotal suppliers (TPS) test under non-emergency conditions and only select cost-based offers when a resource fails the TPS test.

Several stakeholders took issue with presenting a proposal that was voted on months in the past as the presumptive motion to advance at the MRC. It was suggested that a proposal sponsored by the Monitor during last year's deliberations should be considered at the MRC as well and the truncated voting rules waived to allow the two to be voted on side-by-side. ■

— Devin Leith-Yessian

SPP News

SPP Files to Incorporate Western Entities into RTO

MOPC Endorses JTIQ Cost Allocation with MISO

By Tom Kleckner

SPP reached a major milestone June 4 in its efforts to expand into the Western Interconnection when it filed bylaw amendments at FERC to place seven Western entities under its tariff (*ER24-2184*).

The revisions would make the RTO the first grid operator with markets in both major interconnections.

SPP said its expansion will create economic and reliability benefits for all its member companies through access to a larger generation fleet, greater geographic diversity and increased efficiencies in SPP's energy markets.

The efficiencies would come by using a single market "optimized solution" across the DC ties that connect the Western and Eastern Interconnections. SPP said that will increase resilience by "leveraging" diverse resources through 510 MW of bidirectional capability, bringing price convergence across the ties.

"Years of collaboration among SPP staff, existing RTO members and Western entities has resulted in a revised tariff that meets the unique needs of all the entities we serve, and I couldn't be more thrilled," SPP CEO Barbara Sugg said in a *statement*.

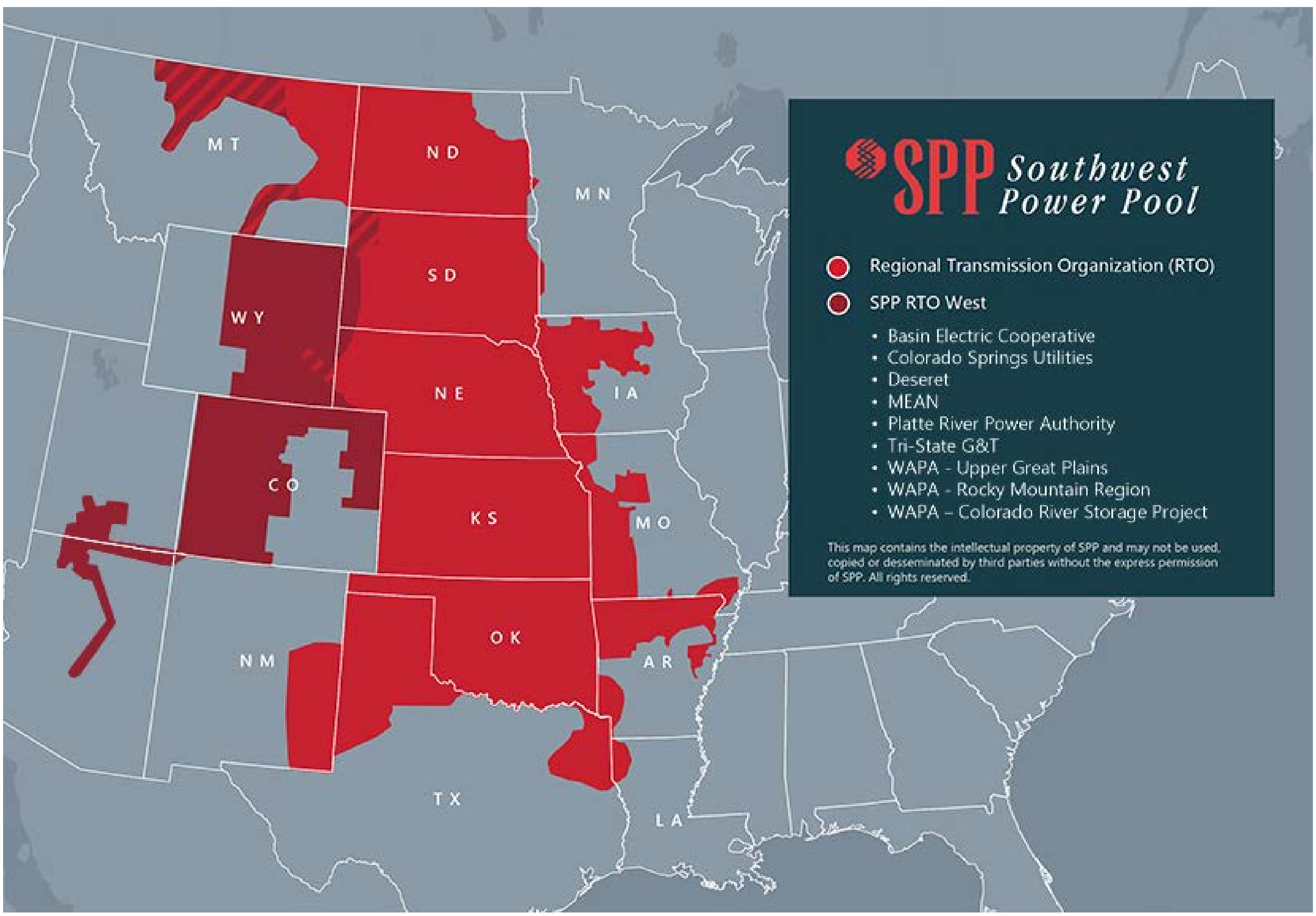
The grid operator said its newest members can expect to see more than $200 million in annual benefits. It *said* the Integrated Marketplace saved Eastern Interconnection members $3.6 billion last year.

SPP's RTO West is scheduled to go live in April 2026.

The bylaw amendments were approved during the May 7 meeting of the Board of Directors and Members Committee. The board also approved a package of 16 tariff revisions that include establishing a Western balancing authority area and managing transactions across the DC ties.

Settlements will be based on transmission service reservations during the market's first four years. After that, they will be based on transmission congestion rights. (See "Bylaw Changes for RTO West," *SPP Board of Directors/ MC Briefs: May 7, 2024*.)

SPP has been quietly working with parties



| *SPP*

SPP News

interested in *evaluating* the benefits and requirements of RTO membership since October 2020. Initial RTO expansion terms and conditions were approved in July 2021, and the DC tie terms and conditions in July 2022.

The entities pursuing RTO membership are:

- Basin Electric Power Cooperative;
- Colorado Springs Utilities;
- Deseret Power Electric Cooperative;
- Municipal Energy Agency of Nebraska;
- Platte River Power Authority;
- Tri-State Generation and Transmission Association; and
- the Western Area Power Administration's Colorado River Storage Project Management Center, Rocky Mountain and Upper Great Plains regions.

The expansion would add Arizona, Colorado and Utah to SPP's current 14-state footprint and increase the size of its service territory in Wyoming. SPP's Regional State Committee, composed of regulators from the RTO's states, would add four new seats to accommodate the new members.

Representatives from the seven entities would serve on the Members Committee and SPP's key stakeholder group, the Markets and Operations Policy Committee. Also, several Western-specific working groups would be formed to focus on issues affecting the new members.

Tri-State CEO Duane Highley, who led SPP member Arkansas Electric Cooperative Corp., said his organization is "enthusiastically" looking forward to participating in RTO West as it looks to advance its energy transition.

"The full benefits of the RTO, including a day-ahead market, an ancillary services market, efficient regional transmission planning, common transmission tariff and participatory governance model, help us to further reduce costs for our cooperative members across the West," he said.

"The RTO offers unprecedented access to regional transmission and generation resources that will help us reach our emission-reduction goals, add more renewable energy, manage customer costs and ensure the reliability of our electric grid," Colorado Springs CEO Travas Deal said.

JTIQ

MOPC on June 7 approved a tariff revision request that establishes a cost-allocation framework for projects in the Joint Targeted Interconnection Queue (JTIQ) with MISO.

The change (*RR620*) addresses chronic transmission issues along the seam with MISO related to generator interconnection requests and implements cost-allocation policies already approved by SPP's state regulators. It also memorializes and defines how the JTIQ process will be implemented and applied once executed.

SPP and MISO have been working since 2020 to identify projects along their seam that can help unlock new generation and resolve congestion issues in the absence of interregional projects. They have agreed on a direct billing approach that assigns 90% of the JTIQ portfolio's $1.06 billion in costs for its five projects to generation. Load will cover the remaining 10%. (See *MISO, SPP Propose 90-10 Cost Split for JTIQ Projects*.)

"The revision request determines how we'll treat costs, security requirements and congestion-hedging mechanisms," SPP's Aaron Shipley told MOPC members. "We feel the benefits help provide some longer-term solutions and a different way to think about chronic issues ... hopefully bringing added capacity to that area and helping those issues."

The measure passed with 89% approval over opposition from renewable interests. While recognizing the need to facilitate more generation in areas that have been "struggling," they said the framework risks the JTIQ's success.

"The reason we are where we are today is in part because of the failure of our interregional planning processes to produce anything meaningful," the Advanced Power Alliance's Steve Gaw said. "This is the first time that projects are even at a point where there could be some projects that come out of this. The only reason it's moving forward is because the costs are being assigned to generators, and that should not be the way we look at how we do regional planning. We should be looking at how this potentially gets us to a point where we have [a] significant look at who's benefiting and how those benefits flow."

The RSC (*June 10*), and the board and the MC (*June 12*), will take up RR620 in similar special meetings. SPP will coordinate the FERC filing with MISO, which also has several special meetings set up in June. The RTOs are targeting a filing by August.

SPP will seek board approval of the JTIQ portfolio if FERC accepts the tariff revisions and updates to its joint operating agreement with MISO. ■

SPP News

SPP: Enough Generation to Meet Summer Demand

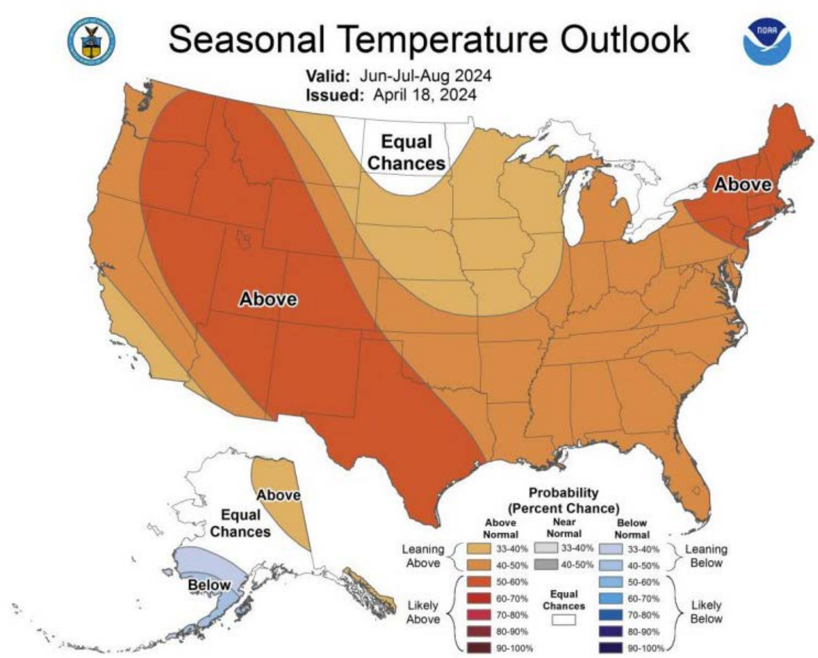
SPP said June 3 that it expects to have enough generation to meet energy demand despite higher regional temperatures this summer, sharing the same message it did earlier with stakeholders.

Staff speaking at the RTO's biannual Emergency Communications User Forum on May 21 said SPP's biannual seasonal assessment showed the grid operator has a 90% probability of being equipped to serve all loads during summer peak usage hours. The assessment indicates summer operations should be normal with no extreme operational situations.

Meteorological models predict a 33 to 50% chance of above-normal temperatures this summer at varying levels in the 14-state SPP footprint. Similar percentages exist for below-normal rainfall in its region, the RTO said.

"While we anticipate no major concerns this summer, we are prepared for any circumstance," SPP's Bruce Rew, senior vice president of operations, said in a *press release*. He added that the RTO is confident "in our ability to keep the lights" on despite a forecast of higher-than-normal temperatures.

SPP says it has the systems, tools and procedures in place to mitigate risks and maintain reliability should extreme weather, unexpected outages or other events affect the region. It can call on generating units to commit to run earlier or more often than usual, delay planned outages, import energy from neighboring systems or tap into available reserves.



| NOAA

NERC's *2024 Summer Reliability Assessment* found that SPP will have sufficient operating reserves this summer. It projects peak demand could hit 56.32 GW and estimates an anticipated reserve margin of 27.8%. The RTO set an all-time coincident peak of 56.84 GW last August.

SPP has over 101 GW of nameplate capacity. It had 62.16 GW of accredited capacity last year. ■

— Tom Kleckner

Company Briefs

Global Solar Council Revamps Brand

Industry body The Global Solar Council (GSC) last week announced the launch of its new brand and strategic vision, aimed at accelerating the deployment of solar power worldwide.

The GSC said it aims to build a fair and sustainable world with solar power while focusing on three key pillars: policy and advocacy, network building and knowledge, and standard setting and solutions.

"We need to unite the global industry to address our common challenges, maximize deployment and deliver the solar revolution at speed, scale and to the highest quality standards," GSC CEO Sonia Dunlop said.

More: *Renews*

Entergy, NextEra to Develop 4.5 GW of Storage Projects

Entergy and NextEra Energy Resources last week announced they have entered into an agreement to develop up to 4.5 GW of new solar and storage projects.

The five-year agreement will help Entergy provide renewable energy to customers in Arkansas, Louisiana, Mississippi and Texas.

"We believe the power sector is at an inflection point, and growing electricity demand will be met by low-cost, renewable generation and storage," NEER CEO Rebecca Kujawa said.

More: *Reuters*

Tri-State Buys 2 Colorado Solar Projects

Tri-State Generation and Transmission Association last week announced it will purchase the 145-MW Axial Basin Solar project in Moffat County and the 110-MW Dolores Canyon Solar installation in Dolores County.

The projects are expected to begin delivering power for Tri-State's member systems late next year and will move the Colorado-based cooperative to a milestone of 50% renewable energy use.

Financial terms were not disclosed.

More: *POWER Magazine*

Federal Briefs

US Solar Projects Could Boom amid Tariff Deadline

A two-year U.S. tariff holiday on solar panels from Southeast Asia expired June 6, starting the clock for American project developers to use the equipment they stockpiled duty-free over that period by the end of this year.

The dynamic could result in a mini-boom in U.S. solar installations as developers have accumulated about 35 GW of imported panels in warehouses since President Joe Biden lifted the duties on Malaysia, Thailand, Cambodia and Vietnam in 2022. That is nearly as much solar capacity as the U.S. will install during all of 2024, according to research firm Wood Mackenzie.

Companies will have just 180 days to use that stock or they will need pay taxes on it.

More: *Reuters*

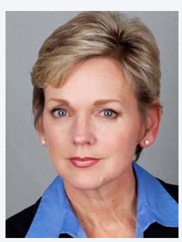
Report: Carbon Dioxide Levels Rising 'Faster than Ever'

Carbon dioxide gas levels in the atmosphere are rising "faster than ever," according to a report published by the National Oceanographic and Atmospheric Administration and Scripps Oceanographic Institute.

The report found that carbon dioxide has reached a record 427 parts per million and comes after 2023 was the hottest year on record. Carbon dioxide levels are also increasing at record levels. The early-2024 rise in carbon dioxide concentrations was the highest in history, and the increase from 2022 to 2024 may have been the largest two-year jump in the annual May peak ever recorded.

More: *The Hill*

Granholm Calls for More Nuclear Power While Celebrating Vogtle



Energy Secretary **Jennifer Granholm** last week called for more nuclear reactors to be built in the U.S. and worldwide while celebrating the commercial operation of the Plant Vogtle expansion in Georgia.

Granholm said the U.S. needs 98 more reactors with the capacity of Vogtle Units 3 and 4 to produce electricity while reducing climate-changing carbon emissions. Despite agreeing with Granholm's sentiment, Southern Co. CEO Chris Womack said his company won't build more any time soon mainly because of cost overruns. Granholm said she believed others could learn from Vogtle's mistakes.

The new Vogtle reactors are projected to cost Georgia Power and three other owners $31 billion. Add in $3.7 billion that original contractor Westinghouse paid Vogtle owners to walk away from construction, and the total nears $35 billion.

More: *The Associated Press*

Summer May Bring 8% Rise in Utility Cost for Many Americans

Many people in the U.S. can expect to see an 8% rise in their utility costs this summer, according to a new report from the National Energy Assistance Directors Association and the Center for Energy Poverty.

The analysis found that the average cost to cool a home this summer would reach $719, up from $661 last year and $476 a decade ago. The Mid-Atlantic and West Coast are expected to see the highest rise in electricity costs compared to last year, at 12%.

More: *The Guardian*

State Briefs

ARIZONA

Utilities Won't Disconnect Power in Extreme Heat

Arizona Public Service, Tucson Electric Power and UNS Electric last week opted not to disconnect residential customers from June 1 through Oct. 15.

SRP said it will not disconnect residential customers for nonpayment during July and August. In other months, SRP will not disconnect customers' power for nonpayment during an excessive heat warning issued by the National Weather Service.

The Corporation Commission gave utilities had two options: utilize the June 1-Oct. 15 disconnection moratorium period, or suspend disconnections if the forecasted temperature exceeds 95 degrees.

More: *KPNX*

CALIFORNIA

Lawmakers, Newsom in Standoff over Loan to Keep Diablo Canyon Open

Lawmakers last week rejected Gov. Gavin Newsom's bid to include an additional $400 million for Pacific Gas and Electric in the state budget to keep the Diablo Canyon nuclear power plant open.

Newsom cut a $1.4 billion deal to keep the plant operational until 2030 amid record summer temperatures and a budget surplus in 2022. Now that the state is facing a deficit, legislative leaders have cut the money from the budget proposal.

Lawmakers raised concerns that the state may never be paid back for hundreds of millions in loans to PG&E despite promises of reimbursement. The federal government is only partially covering the loan, with specific terms attached, and lawmakers say they are concerned the ultimate hit to the state's general fund could be up to $659 million.

More: *The Fresno Bee*

San Diego Municipal Utility Question Heads to City Council

Power San Diego, a group that wants to oust San Diego Gas & Electric within the city limits and replace it with a municipal utility, have collected enough valid signatures to pose the question to the City Council.

The group originally failed to collect enough signatures to automatically put its proposal on the November ballot, but it succeeded in getting it before the council. The group turned in nearly 31,000 signatures to the San Diego County Registrar of Voters. As per the state elections code, a random number of the signatures were examined and the projected number of valid signatures on the petition came to 24,167 — 161 signatures above the amount needed to take it to the council.

Under the proposal, the municipal utility would only handle the electricity distribution responsibilities for customers strictly within the city limits of San Diego.

More: *The San Diego Union-Tribune*

GEORGIA

Kia Unveils First EV at West Point Factory

Kia last week released its EV9, the first electric vehicle manufactured in the state.

Gov. Brian Kemp drove the vehicle off the production line last and congratulated the Kia team for helping boost the state's EV portfolio. The vehicle went on sale at the end of 2023, were shipped from South Korea and are sold in all 50 states.

The MSRP range is between $55,000 and $70,000.

More: *Ledger-Enquirer*

MAINE

PUC Orders Audit of Versant Power

The Public Utilities Commission last week ordered an audit of Versant Power, citing unspecified "questions and concerns" related to rate increases and other actions.

The PUC did not say precisely why it directed the audit, but it cited four cases, including two for distribution rate increases that Versant says are needed to improve service and operations. Of the other two cases, one was Versant's request in 2019 to reorganize with its new parent company, Enmax. The other resulted in reliability benchmarks.

The commission hired an outside firm to conduct the audit and will not participate in any findings of fact or conclusions of law.

More: *Portland Press Herald*

MARYLAND

O'Donnell Announces Retirement from PSC

Public Service Commissioner Anthony O'Donnell announced his retirement on June 1.

O'Donnell served on the commission for nearly eight years after being appointed by Gov. Larry Hogan in 2016. He also served as the chair of the Subcommittee on Nuclear Issues-Waste Disposal and as a member of the Committee on Electricity for the National Association of Regulatory Utility Commissioners.

"Tony O'Donnell is the best example of a true public servant," PSC Chair Frederick H. Hoover said in a statement. "It has been an honor to serve alongside him on the PSC bench."

More: *Maryland PSC*

MICHIGAN

DTE, Consumers Energy Enact Time-of-use Rates

DTE Energy and Consumers Energy began using their summer time-of-use rates at the beginning of this month.

The summer rates, which are in place through September, will charge customers more for energy use during peak hours. Peak-hour rates also increased during the summer.

For Consumers customers, peak hours are weekdays from 2 to 7 p.m., and electricity will cost about 5 cents more per kilowatt-hour. During the rest of the year, electricity costs about 1 cent more during peak hours.

DTE customers will pay about 7 cents more from 3 to 7 p.m., compared with 2 cents more during peak hours any other time of the year.

More: *Bridge Detroit*

Outage-prone Utilities Could Face $10M in Annual Fines

The Public Service Commission last week unanimously voted to seek public feedback on a new straw proposal intended to allow financial penalties against utilities whose customers have common and long-running power outages.

A maximum of $10 million in fines could be charged to utilities if they fail to meet improvement benchmarks. Examples include the frequency of power outages and how many customers get electricity restored within 48 hours of catastrophic weather events. The proposal recommends at least seven new financial penalties based on various grid reliability and resilience measurements.

More: *MLive*

NEVADA

Arevia Power Signs PPA with NV Energy for Solar+Storage Project

Arevia Power last week announced the signing of a power purchase agreement with NV Energy for the largest solar and battery storage project in the state.

The $2.3 billion Libra Solar Project, which features a 700-MW solar facility paired with 700 MW of storage, is expected to be operational in 2027.

"NV Energy is committed to a future that provides renewable energy to all our customers, where large-scale and cost-effective solar solutions make up a substantial portion of Nevada's energy generation," said CEO Doug Cannon.

More: *Arevia Power*

NEW YORK

NYSERDA Allots $5M for Agrivoltaic Demo Projects

The New York State Energy Research and Development Authority (NYSERDA) last week made $5 million available for demonstration projects that co-locate solar siting and agricultural operations in the state.

Through the Environmental Research Program, the funding will support researchers, solar developers, farmers, nonprofit organizations and local governments interested in agrivoltaics.

Applications will be accepted through Sept. 12. Funding for the program is through the Regional Greenhouse Gas Initiative.

More: *Solar Industry Magazine*

OHIO

PUC Approves AES Transmission Charges

The Public Utilities Commission last week approved a bid by AES Ohio to increase its transmission cost recovery rider.

In so doing, the PUC overruled an objection from the Office of the Ohio Consumers' Counsel (OCC) to what the office said is a 53% increase in what AES Ohio charges residential consumers for transmission. The increase would raise customers' bills by 2.26%.

The OCC filed a complaint with FERC asking it to regulate the charges.

More: *Dayton Daily News*

OREGON

PacifiCorp to Pay $178 million to 2020 Wildfire Victims

Pacific Power, part of PacifiCorp, last week agreed to a $178 settlement with more than 400 plaintiffs in the latest multimillion-dollar payout related to the 2020 wildfires.

The majority of the 403 plaintiffs in the settlement were affected by the Echo Mountain Complex Fire, while others were impacted by the Santiam Fire. The blazes killed nine people, burned more than 1,875 square miles and destroyed thousands of homes and other structures.

More: *Oregon Public Broadcasting*

PENNSYLVANIA

County Says Unused Dam Could Provide Green Energy

Montgomery County officials last week hosted a public meeting on a potential project to use the Norristown Dam to generate hydroelectric power.

Officials recently submitted an initial consultation document to FERC to start what will be a two- to five-year process. The project would generate an estimated 7,300 MWh annually.

The project has been years in the making. The county took ownership of the dam from PECO Energy in the 1990s and began exploring options to generate hydroelectric power in 2016.

More: *WHYY*

VIRGINIA

Regulators Approve Dominion Request to Drop RGGI Fee from Bills

The State Corporation Commission last week approved a request from Dominion Energy to drop a $4.50 charge from customers' bills tied to the state's participation in the Regional Greenhouse Gas Initiative, to which it no longer belongs.

Dominion made the request last month after finalizing its costs for RGGI compliance following the state's withdrawal from the market at the end of 2023, prompted by Gov. Glenn Youngkin's regulatory action. Dominion will zero out the rider by July 15 after seeing what is recovered through May 31.

More: *Virginia Mercury*

State to Exit Calif. EV Mandate at End of Year

Gov. Glenn Youngkin last week announced the end of the California electric vehicle mandate in Virginia, effective at the end of 2024 when California's current regulations expire.

In 2021, the General Assembly passed legislation authorizing the state Air Board to adopt California's Advanced Clean Cars I regulation. The California Air Resources Board recently adopted Advanced Clean Cars II, set to take effect Jan. 1, 2025, which would require 100% of new cars sold in model year 2035 to be EVs. An opinion from Attorney General Jason Miyares confirms the law as written does not require Virginia to follow ACC II. Therefore, it will follow federal emissions standards on Jan. 1, 2025.

More: *Office of Gov. Youngkin*

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