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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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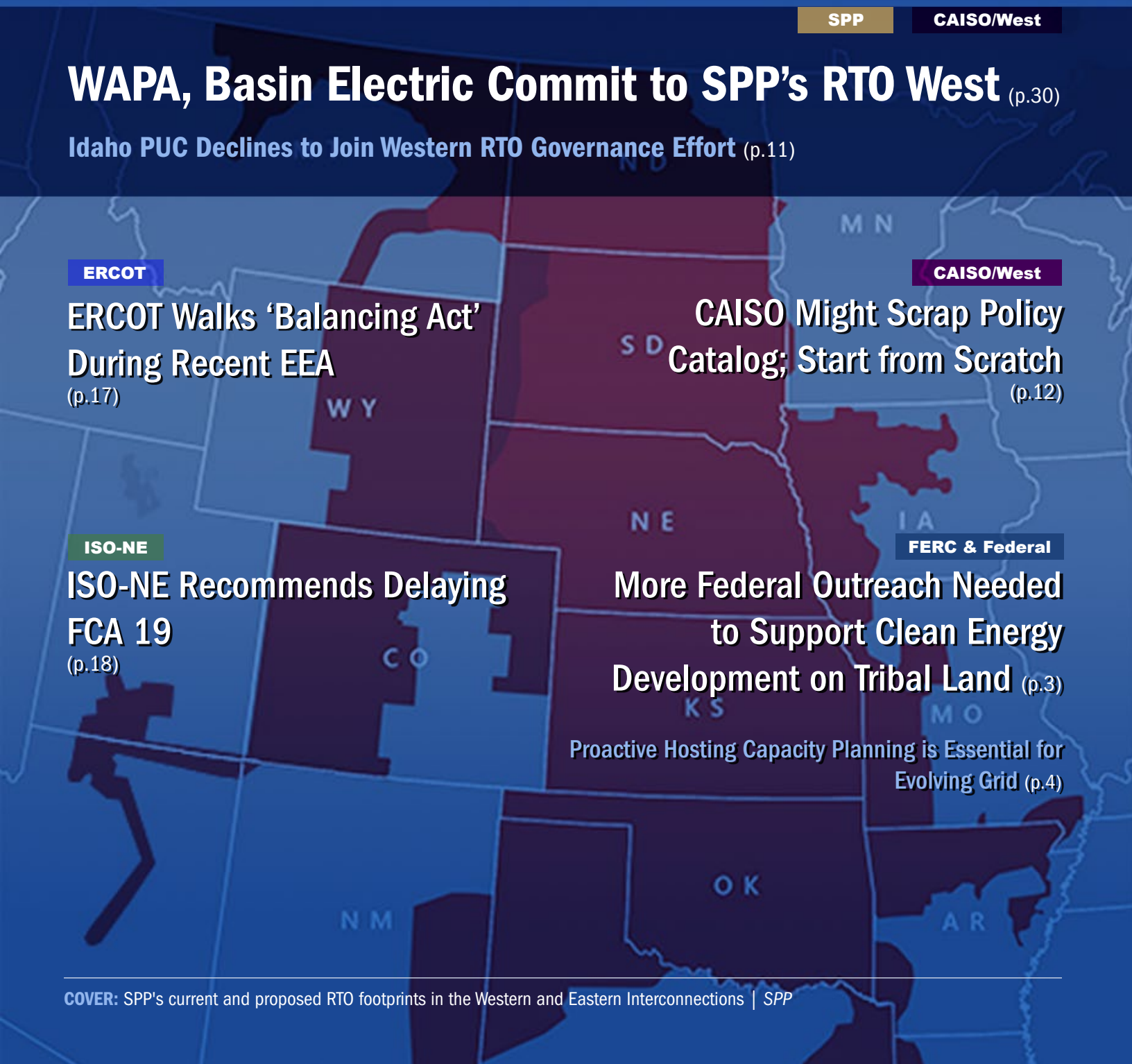

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FERC/Federal News

More Federal Outreach Needed to Support Clean Energy Development on Tribal Land

Hundreds of Tribes are Federally Recognized, and Each Works Differently

By Dej Knuckey

LAS VEGAS — The government and developers need innovative capital approaches and a commitment to building deep relationships to unlock the potential of clean energy development on tribal lands, experts said in a panel at last week's RE+ conference held held at the Venetian Expo and Caesars Forum.

However, the federal government is behind on outreach to tribal leaders about how to address financing and skill gaps, *RTO Insider* was told.

Tribal land accounts for 5.8% of the U.S. landmass but 6.5% of utility scale renewable energy generation potential, said Margaret Tallmadge, senior development manager at Navajo Power, a majority native-owned utility scale solar developer working with tribal nations and communities across the U.S.

Barriers to developing this "outsized potential" include "access to capital; limited opportunities to build technical capacity and internal capacity within tribes to pursue their own projects; and minimal knowledge of tribal sovereignty, federal Indian law and regulatory complexities in Indian country," Tallmadge said.

Some of those barriers are exacerbated by the federal government, which is lagging in its trust responsibility to tribes, Paul Dearhouse, a senior consultant to the Tribal Energy Loan Guarantee Program at the U.S. Department of Energy's Loan Programs Office (LPO), told *RTO Insider*. "We're a few years behind in actually sending out a 'Dear Tribal Leader' letter, saying, 'Here's a program designed to finance tribal energy projects. What's your thoughts? What's your feedback? What are the best ways to do that?' We haven't done that to date."

Tribal input is vital to develop appropriate ways of dealing with the unique challenges tribes may face, where they have land ideal for renewables development but little access to capital and often no experience working with developers whose incentives and financing structures are designed with short-term ownership rather than long-term land stewardship in mind.

Developers working with tribes also need to be innovative, balancing the need to craft project structures that enable the tribe to participate without a large capital outlay with financiers' desire to have traditional PPAs, said Kevin Blaser, managing director of energy systems at Bakinaw Federal Contracting.

From left: Margaret Tallmadge, Navajo Power, PBC; Kevin Blaser, Bakinaw Federal Contracting; Jennifer Hershman, SOLV Energy; Paul Dearhouse, Tribal Energy Loan Guarantee Program, U.S. Department of Energy; and Dave Harper, Alliance for Tribal Clean Energy | © *RTO Insider LLC*

One example of where limited access to capital creates issues is with interconnection queues. While a pain point for most utility-scale development, they create an even larger challenge for projects on tribal lands, Dearhouse said. FERC orders and rules implemented at the RTO level to fix aging infrastructure can result in escalating fees to maintain a project's position in the interconnection queue. Most tribes won't have the large amount of capital needed to maintain their queue position, creating "a huge barrier," but also an opportunity.

"This is a new frontier to make our LPO offerings better, to do a proper rulemaking for our program and to really listen to tribes that are in the queues across the nation, to ask: 'Are there better ways that the Loan Programs Office could design the program to help address that specific gap?'" he said.

Developers Must Invest in Relationships

While funding mechanisms are important, developers seeking to build clean energy resources on tribal lands must start with building a relationship, Blaser said. "If you're going to work or partner with tribes — and there's a ton of benefits to doing that — you really have to take the time to learn their culture, learn what they're trying to do, and understand what their strategy is, even if their strategy is 'we don't know.'"

There is no single right way of working with tribes, Blaser said: "Because there are 576 or so federally recognized tribes, there are 576 different ways of doing it. There are all those bodies of laws; every culture is different."

A long-term perspective and partner mentality is essential as developers work with tribes, said Dave Harper, head of tribal engagement at the Alliance for Tribal Clean Energy. "You don't want to be an outsider; you want to come in as a partner mentality. What does being a partner mean? It means that we're going to be fair with each other, we're going to be respectful. We're going to be able to have dialogue and to sit down."

Tribes need to use those partnerships when they have limited internal knowledge or bandwidth, Dearhouse said. "For utility-scale projects, many times a tribe has a part-time environmental coordinator, so they really have to bring in trusted partners like the fellow panelists here that can really help fill in that piece."

A relationship with the LPO also is important for tribes seeking to deploy renewable projects on their lands. "We are long-term patient capital. The path that we walk to get a tribal applicant in the door through to funding can be long, months to even a couple of years, because of the steps that we take, but for a really responsive applicant, it can be expedited two months, but not every tribe's ready." ■

FERC/Federal News

Proactive Hosting Capacity Planning is Essential for Evolving Grid

Experts Call for Mandating Transparency, Streamlining Processes to Create Speed, Fairness

By Dej Knuckey

LAS VEGAS — Utilities and customers both benefit when proactive hosting capacity planning is used to get ahead of the rising demand for distributed energy resources, said panelists at the *RE+* conference, held last week at the Venetian Expo and Caesars Forum.

Looking ahead at the potential for distribution circuits to handle high penetrations of DERs not only prevents unfair allocation of upgrade costs but also enables utilities to prioritize upgrades where they are needed most.

Transparency is an essential part of proactive hosting capacity planning, said Erin Ankeney, director of interconnection at residential solar installer Freedom Forever.

"Utilities should be mandated to have their information public about hosting capacities and their availability on the grid. It shouldn't take a customer and the contractor to get through the whole contract to find out that the system size that was submitted or proposed is not eligible to be installed in that area without a costly upgrade," she said.

Utilities need to end today's practice of reviewing one interconnection application at a time and expecting the customer that triggers the need for a distribution grid upgrade to pay the full costs, said Radina Valova, regulatory vice president at the Interstate Renewable Energy Council.

With proactive hosting capacity planning, the utility "would begin by estimating the hosting capacity of distribution circuits in advance of setting any particular project, then analyze the circuit's ability to accommodate the anticipated DER growth and would determine where any potential infrastructure upgrades have to happen," Valova said. "The utility would proactively undertake those upgrades and then apply optimal recovery."

Ankeney said antiquated rules and procedures are "not keeping up with the growth of the DERs and the scale of complexity that we're seeing in today's market." She said challenges ranged from administrative pain points, to engineering screens, to grid transparency.

The result is a slow and frustrating process, Ankeney said. "We're seeing anywhere from 20 to 30 business days just to get [a residential system] approved to install, whereas on the commercial side, we're talking hundreds of days or years." After the project is built, "we have to also go through those same timelines to get jobs interconnected and fully operational with permission to operate," she said.

From left: Moderator Radina Valova, Interstate Renewable Energy Council; Erin Ankeney, Interconnection, Freedom Forever; Lara Aston, Pacific Northwest National Laboratory; Dave Gahl, Solar and Storage Industries Institute (SI2); and Samantha Weaver, Coalition for Community Solar Access (CCSA) | *© RTO Insider LLC*

Utilities' application systems are also antiquated, and delays can stem from something as petty as mis-entering a customer's address, a problem easily eliminated by the kind of simple address validation used on every ecommerce site.

Interconnecting the DER Dots

Some states — but not enough — are already beginning to explore proactive hosting capacity planning, said Samantha Weaver, director of interconnection and grid integration policy at the Coalition for Community Solar Access. While 21 have an active proceeding on distribution system planning requirements, "only a handful of those states are looking at distribution system planning in the proactive hosting capacity planning concept. This is not a widely practiced concept yet."

Weaver said New Jersey, Maryland and Massachusetts are engaged in the preliminary discussions. "What they all have in common is that they are all seeking to develop a framework for utilities to recover investments in distribution infrastructure in advance of projects seeking to interconnect.

"For example, both Maryland and New Jersey have proposals in the early stages that would require utilities to forecast congested areas on the distribution system and propose system upgrades accordingly. Then you get into questions around how much those upgrades cost and who pays for them. The way that Maryland and New Jersey are looking at this is they're proposing a $1/kW hosting capacity upgrade fee. Each interconnecting customer who comes along will have to pay to interconnect under this framework."

Weaver said both states' proposals fail to solve one key problem related to cost allocation: "Eventually these upgrades reach a point where they become too expensive for a single project or even a group of projects to support. So even if these high costs to upgrade a substation are shared among all future interconnecting customers, they're still too high, and nobody's going to build a project there."

Studies in Maryland have shown realistic hosting capacity fees would be $500 to $1,000/kW, Weaver said. "Those are project-killing costs."

DERs with Ph.D.s: An Explainer

The grid is an ecosystem, not a science experiment: It's impossible to hold everything constant while changing only one variable.

This means that utilities cannot assume everything else stays constant on a distribution circuit as one variable — the number of buildings with rooftop solar, for example — changes. The evolving nature of DERs means that there are many changes happening simultaneously: rooftop solar adding to the grid in the day; batteries sopping up the excess and storing it for when it's needed; and electric vehicles plugging in and not only charging during the night, but possibly feeding into the house during peak demand.

The intersection of big data and small energy has resulted in sophistication well beyond reacting to simple demand response requests. A home battery management system, for example, may layer customer-defined parameters (always having at least 30% charge at the end of an evening) with forecast inputs (tomorrow will be sunny), predicted demands (weekend road trips mean the EV will drink a lot of electrons Saturday night) and scenario planning (hot dry summer means more likelihood of a planned blackout to lower fire risk).

Add to that the increasing sophistication of the many players in a home's DERs, such as a bidirectional charger that can tap into an EV's many Powerwalls worth of energy storage, or a hybrid hot water tank that can act as a thermal battery, and capacity planning isn't simply additive. Modeling capacity today needs to account for the potential of some DERs to help smooth out or even negate the rising demand coming from electrifying homes and transportation. ■

FERC/Federal News

Moody's: Permitting Process Holding Transmission Back, Risking Reliability

By Holden Mann

Transmission investments that could help "address reliability, congestion and cybersecurity concerns" in the nation's electric grid are being held back by "regulatory tension" between the federal and state governments, according to a recently released report from Moody's Investors Service.

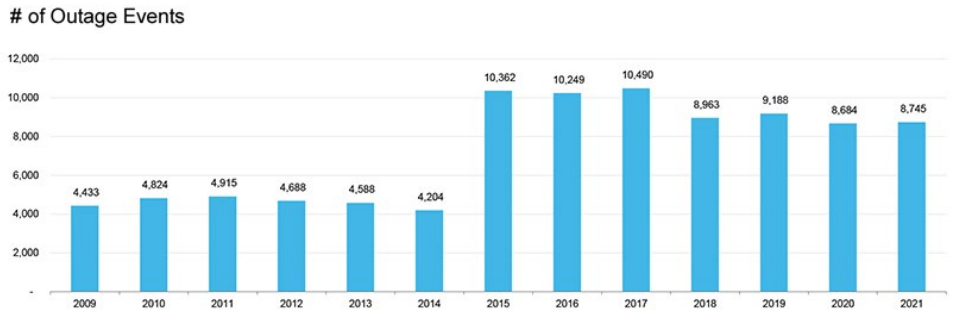
The *report*, published Sept. 11, asserts that not only is massive transmission investment needed to keep pace with the growth of new wind and solar generation sources and aging infrastructure, but "opportunities abound" for developing transmission assets. However, in spite of support from decarbonization initiatives at various levels of government, the siting and permitting process represents a significant bottleneck for utilities with the experience and resources to carry these projects out.

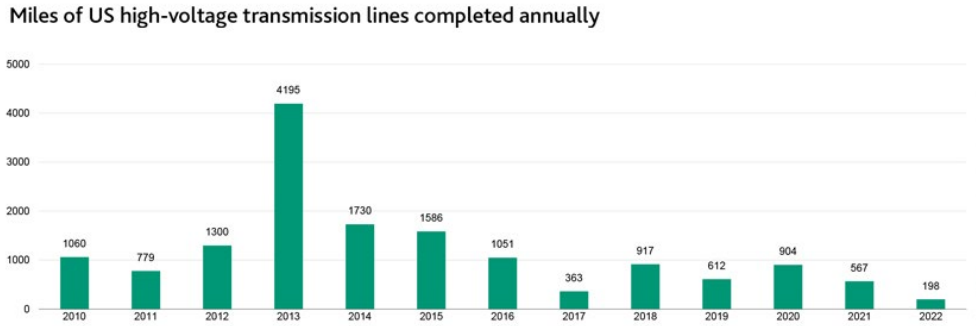
North America's grid is long overdue for an upgrade, Moody's argues in the report, citing data from NERC showing an annual average of about 9,500 "momentary or sustained transmission outage events" between 2015 and 2021, a figure "more than double the annual average of the preceding five years." The report attributed most of these outages to severe weather events, which have become "more frequent and severe" in recent years.

Transmission improvements could be extremely useful to help the grid absorb the impact of such events, Moody's said, citing a report from consulting firm *Grid Strategies* studying the winter storm of February 2021. More interregional transmission capacity could have saved nearly $1 billion in impact — and kept the lights on for 200,000 homes — for each gigawatt added, the report said.

Transmission improvements could also help with high congestion costs, which Moody's said "have emerged as a major problem" in recent years; the firm cited data from the U.S. Energy Department's draft *National Transmission Needs Study* indicating that congestion costs in the Mid-Atlantic region surged from $529 million in 2020 to $953 million the following year. Additional investment is needed to bring the transmission system in line with mandatory cybersecurity requirements adopted in response to mounting threats from malicious online actors around the world.

FERC has sought to encourage transmission investments, the report said, noting "limited revenue risk [and] counterparty risk" on the part of transmission owners thanks to the commission's cost recovery framework and transparent process for setting return on equity for transmission assets. The report considered revenue collected under FERC's regulatory framework to be overall "more stable and predictable than" under state regulations and called the commission's approach "favorable to transmission owners."





Annual transmission outage events since 2009 (top) and miles of U.S. high-voltage transmission lines completed annually | *Moody's*

While FERC has tried to cultivate a positive environment for TOs — particularly large utilities such as Duke Energy and Exelon, which Moody's called "best positioned to take advantage of" these opportunities — challenges remain in the approval process. The report noted that authority over transmission siting and permitting largely remains in the hands of state and local governments, which "can be slow and impede the pace of transmission development."

This regulatory dilemma is illustrated by the slowing pace of transmission capacity upgrades, Moody's said, pointing to data from FERC that shows an average of around 600 miles of high-voltage transmission lines completed annually in the U.S. since 2017, far below the 2,000 average annual miles completed between 2012 and 2016. The slow pace of construction, in spite of steadily rising transmission investments since 2017, has resulted in long lead times for such projects, with Moody's estimating up to 10 years is needed from preliminary planning to end of construction.

Moody's said efforts are underway in the federal government to help with the permitting issue, citing Sen. Joe Manchin's (D-W.Va.) *Building American Energy Security Act* as an example of the kind of work that could help with getting transmission projects moving. Among other reforms, the bill would set maximum timelines for permitting reviews and set a statute of limitations for court challenges to projects.

"Measures like these at the federal level, as well as improved coordinated planning at the state and regional level, could facilitate the nation's transmission development and help meet long-term greenhouse gas emission goals," Moody's said. ■

FERC/Federal News

Efficiency and Reliability Debated at House Energy Hearing

By James Downing

The partisan divide on energy efficiency and other policies was on display at a hearing Wednesday of the House Energy and Commerce Committee's Energy, Climate and Grid Subcommittee.

The panel examined a series of bills from Republicans, including the Guaranteeing Reliable Infrastructure Development (GRID) Act from subcommittee Chair Jeff Duncan (R-S.C.), which would require any federal agency implementing a rule that affects reliability to bring it before FERC. Other legislation would delay a Department of Energy proposal to implement new efficiency standards for distribution transformers for five years and limit the department's ability to issue new efficiency standards across the board.

Duncan cited the recent NERC report that listed energy policy as threatening reliability as a reason to support his bill requiring more oversight by FERC. (See *ERO Adds Energy Policy to Risk Priorities List.*)

"There's a looming resource adequacy crisis. We all need to take this morning seriously and do more to ensure reliability and affordability of the energy system," Duncan said. "FERC has allowed the distortion of market incentives such as state and federal subsidies aimed at promoting the deployment of renewables to interfere with electricity price formation. This has contributed to the early retirement of reliable generation assets like nuclear and natural gas."

EPA's proposed power plant rule would add to the problem as it would limit the amount of time fossil plants can operate, he added.

The GRID Act is a broad proposal that would cover many potential government actions, making it hard to determine just how much work it would give to FERC, said David Ortiz, director of the commission's Office of Electric Reliability.

"As a general matter, FERC and the ERO, NERC, have the necessary expertise to understand and comment on the potential effect of proposed regulatory actions on the reliability of the bulk power system," Ortiz said. "However, fulfilling the goal of the GRID Act would require detailed, interconnection-wide modeling and analysis beyond FERC's capability."

FERC might not have access to the data needed to perform the studies required under the proposed bill, he added. Other organizations could do the analysis, with Ortiz pointing to DOE's national laboratories.

Ranking Member Diana DeGette (D-Colo.) said everyone in the room agreed reliability is important and will be even more so in a warming world where summer power outages threaten lives.

"It's clear, a reliable source of electricity is paramount to our nation's health and well-being," DeGette said. "I think that one of the ways to ensure we have reliable electricity is through energy efficiency."

Increasing energy efficiency helps to stretch out the current energy supply to serve more consumers reliably, while also saving them money.

The Biden Administration has been implementing efficiency standards at DOE that would save up to $570 billion after DOE under President Trump missed dozens of deadlines under the law to either issue a standard or explain why none was needed. DeGette argued the bills before the committee do not deal with reliability.

"Instead, what I see is bills that in the name of reliability, would gut energy efficiency standards that are saving Americans money, and that are cutting down on our energy use," she added.

Mid-Carolina Electric Cooperative CEO Bob Pauling in testimony came out against a proposed DOE standard that would require the industry to stop using standard "grain oriented electric steel" distribution transformers at a time when supply chains for the vital infrastructure already are stressed.

"The utility industry needs manufacturers to be 100% focused on increasing output, not adapting to new, government mandated efficiency requirements that are not technologically feasible nor economically justified," he said in written testimony.

DOE Assistant Secretary for Electricity Gene Rodrigues noted that the transformer standard still is just a proposal, which the agency was required to take up under a consent decree, and said the department takes the issue of electric reliability and the need for more transformers seriously.

"That is why DOE expressly asked stakeholders for comment on timelines required for compliance with the proposed standard, as well as comments on the availability of key components," Rodrigues said.

The efficiency standard is just part of DOE's work on transformers. It also is working with the rest of the government and other stakeholders to help bolster the domestic supply chain for key grid components for decades to come, he added.

"We have provided national projections of the long-term demand growth for distribution transformers to provide America's manufacturers with investment certainty that will help them to expand capacity," Rodrigues said. "We have connected manufacturers with suppliers of difficult-to-source grid components. We have utilized legislation passed by this Congress to provide funds for distribution transformers, such as the $10 million in transformer rebates and $10 billion in 48C tax credits." ■

Department of Energy Assistant Secretary for Electricity Gene Rodrigues (left) and FERC Office of Electric Reliability Executive Director David Ortiz testifying at Wednesday's hearing. | *House Energy and Commerce Committee*

FERC/Federal News

EPA Predicts IRA Will Speed Electric Emissions Reductions

New Report Estimates 49 to 83% Decrease from 2005 to 2030

By John Cropley

A *new EPA report* projects significant emissions reductions from the electric power sector by 2030 as provisions of the IRA take hold.

The report — "Electricity Sector Emissions Impacts of the Inflation Reduction Act" — is imprecise due to the range of constraints that could increase or decrease over the next seven years, including policy, technology and availability.

But even the low-end models suggest a large decrease in greenhouse gas output: The electric sector could see a reduction of 49 to 83% from 2005 levels by 2030, or even as high as 91% under advanced-technology scenarios. The report projects a 40 to 68% decrease would occur without the IRA.

EPA was mandated to produce the report as part of the Low Emissions Electricity Program of the IRA.

The report models carbon dioxide emissions reductions with and without the provisions of the IRA. Both scenarios incorporate state and federal policies finalized before Biden signed the IRA into law in August 2022. Neither scenario reflects rules and regulations now being developed or finalized.

The report incorporates data from 10 multi-sector models (changes in generation and use of electricity) and four electric-sector models (changes only in generation) created by EPA, the Department of Energy and the National Renewable Energy Laboratory.

All but one of the models show the bulk of the reductions will result from construction of new wind and solar facilities assisted by IRA incentives; infrastructure buildout assisted by the Infrastructure Investment and Jobs Act; and increased energy storage. The other model relies heavily on carbon capture and storage to reduce emissions.

All the models are based on increased use of low- and zero-emissions technologies and decreased use of high-emission coal- and gas-fired generation.

That is at the heart of the IRA: Its provisions support clean electrical generation, encourage electrification of end uses and promote energy efficiency.

Under the various models, emissions are expected to be 11 to 25% lower in 2030 than in 2005 in the transportation sector, 49 to 63% lower in the buildings sector and 11 to 43% lower in the industrial sector. Economywide, emissions are projected to drop 35 to 43% by 2030.

Transportation is the laggard because of the sheer number of internal combustion vehicles that must be replaced by EVs, and because some modes of transportation may not see wholesale changes attributable to the IRA.

EPA noted that future analyses of the IRA's effects would benefit from completion of processes still in motion — final tax credit guidance on clean hydrogen, for example, or further improvement in technology. Complementary federal, state and local policies are expected to evolve as well.

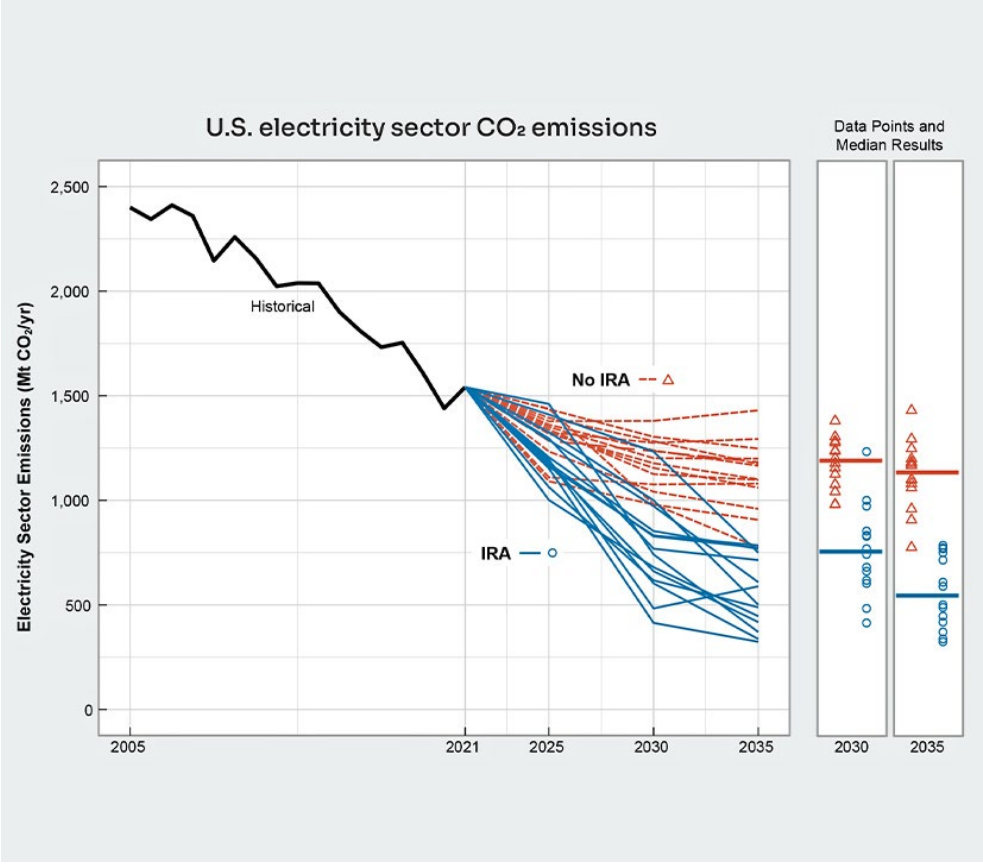
Some IRA tax credits extend beyond 2030, as well. And the technology development and deployment expected to result from the IRA will not be complete by 2030.

In a *news release* last week, EPA called the IRA the most significant policy action on clean energy and climate change ever, and EPA Administrator Michael Regan hailed the impact projected in the report.

"The Inflation Reduction Act is transforming energy production and consumption in dramatic ways, paving the way towards a clean energy future," he said. "This report shows robust evidence that America's clean energy transformation is driving significant reductions in CO_2 emissions, putting us on a clear path to achieve President Biden's bold climate goals."

EPA is part of the executive branch of federal government, and the IRA is a signature achievement of the executive, President Joe Biden.

He faces a tough fight for re-election and the IRA faces a potentially rocky road if he loses or if the Republicans who opposed the package of spending and policy measures succeed in winning control of both chambers of Congress. ■



Projected emissions reductions under various scenarios with and without the Inflation Reduction Act's provisions. | *EPA*

FERC/Federal News

DOE Report Lays out Commercialization Path for VPPs

By James Downing

The U.S. Department of Energy last week released a new "Liftoff" report laying out how virtual power plants (VPPs) can reach commercialization.

VPPs are aggregations of distributed energy resources such as rooftop solar, batteries, electric vehicles and traditional demand response programs.

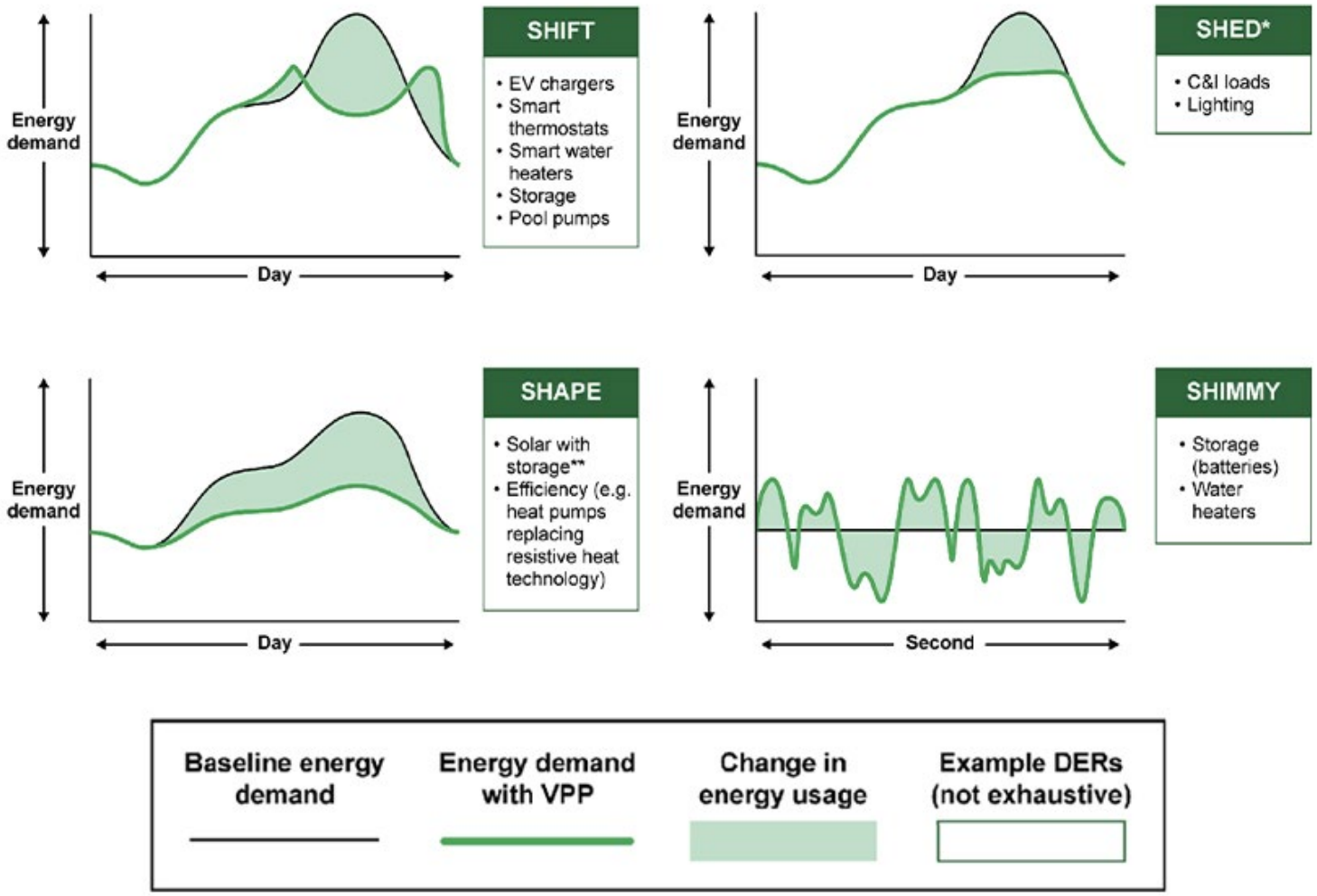
"*Pathways to Commercial Liftoff: Virtual Power Plants*" is meant to start a dialogue between DOE, regulators, policymakers, utilities, ISO/RTOs, corporations, research organizations, advocacy groups and others around challenges and potential solutions for commercialization. It's the fifth Liftoff report, with others covering advanced nuclear, long-duration energy storage, carbon management and clean hydrogen.

Electricity demand is growing nationally for the first time in a decade as fossil plants retire. Deploying 80 to 160 GW of VPPs by 2030, triple the current level, could support rapid electrification compared to building more peaker plants, the report said. National peak demand is expected to grow from 743 GW to 802 GW by 2030, while 162 to 183 GW of generation will retire the rest of this decade.

"In all scenarios, the mix of weather-dependent renewable generation will be unprecedented, leading to more variable electricity supply and higher demand for transmission capacity," the report said. "Transmission interconnection backlogs, which have stretched to an average of five years, pose potential resource adequacy challenges. Large-scale deployment of VPPs could help address demand increases and rising peaks at lower cost than conventional resources, reducing the energy costs for Americans — one in six of whom are already behind on electricity bills."

The report counts between 30 and 60 GW of VPPs currently, largely made up of DR programs aimed at trimming loads when demand spikes. But VPPs can be used for many other activities that benefit the grid, it said.

"Example functions of VPPs on the market today include shifting the timing of EV charging to avoid overloading local distribution system equipment; supplying homes with energy from on-site solar-plus-storage systems during peak hours to reduce demand on the bulk power system; charging distributed batteries at opportune times to reduce utility-scale solar curtailment; dispatching energy from commercial EV batteries back to the grid; and contributing ancillary services to maintain power quality,



A graphic from DOE's report showing how VPPs can shift demand to help keep the grid balanced. | *DOE*

FERC/Federal News

all while minimizing impact to the DER owner," the report said.

VPPs can be 40 to 60% cheaper than the alternatives of utility-scale batteries or natural gas peaker plants, so deploying up to 160 GW by 2030 could save customers about $10 billion annually. That would be enough to contribute 10 to 20% of peak demand, with local differences driven by DER availability and the mix of utility-scale generation.

The economic benefits are in line with a Brattle Group report from this spring, whose authors also worked with DOE staff on the Liftoff report. (See *Brattle Group Finds VPPs Cheapest Alternative for Resource Adequacy*.)

The resources capable of making up VPPs are expected to grow regardless, with EV charging infrastructure adding between 20 and 90 GW each year of nameplate demand capacity and 300 to 540 GWh of nameplate storage capacity from their batteries. It also will add 5 to 6 GW per year of flexible demand from smart appliances and nonresidential DR, another 20 to 35 GW of distributed generation (mostly solar) and 7 to 24 GWh from distributed batteries outside EVs.

The report includes some policy suggestions, such as expanding DER adoption by offering low-cost financing and rebates to induce customers to shift spending to products that can respond to grid needs. The enrollment process in VPP programs could be simplified by adopting opt-out enrollment when consumers buy DER devices, and the sector would benefit from increased customer education, it said.

The operations of VPPs should be standardized so the assets can be more repeatable to shorten the design and pilot stages of individual deployment, it said. The resources also should be integrated into standard utility planning, and utilities need the right incentives to use them.

The resources can be integrated into organized wholesale markets as FERC Order 2222 is implemented in different ISO/RTOs.

VPPs are highly configurable, the report said, meaning they can meet different grid needs at both the distribution and transmission levels. Reshaping demand curves and providing ancillary services can increase grid resilience and cut congestion.

They also are affordable, which is important: While the grid needs major investments, some one in six households already are behind on their electric bills, the report said.

"As lower-cost options for increasing grid capacity, VPPs can moderate the cost burden on ratepayers. They provide services from DERs available on the distribution grid in ways that can be more cost-effective than increasing bulk system resources," the report said.

California is seeing rapid electrification and decarbonization, and some estimates have utilities there spending up to $50 billion to fortify their distribution systems by 2035, but the report said VPPs could cut that by 70%, down to just $15 billion. Demand has been growing rapidly in Texas, by about 9% from 2018 to 2022, and analysis suggests that DERs could save customers $150 per year on average by 2030. ■

FERC/Federal News

Hickenlooper and Peters Introduce BIG WIRES Act

Requires FERC to Set Minimum Interregional Transfer Requirements, but not for Texas

James Downing

Sen. John Hickenlooper (D-Colo.) and Rep. Scott Peters (D-Calif.) on Friday introduced the Building Integrated Grids With Inter-Regional Energy Supply (BIG WIRES) Act, which would require minimum levels of inter-regional transfer capability between regions.

The two have been working on the *bill* for months. It was discussed during the debt ceiling negotiations earlier this year, but ultimately not included in the package that passed. (See *Debt Ceiling Bill Provides 'Mini-deal' on Permitting*.)

"If we want to maintain our national security amidst growing international conflict, make our power system more reliable and cut high energy costs for Americans, we can't have a faulty, outdated electric grid," Hickenlooper said in a statement. "Our bill advances two priorities simultaneously: Make electricity more affordable and build a power grid fit for the 21st century."

The bill would direct FERC to better coordinate construction of an interregional transmission system by requiring each of its transmission planning regions (that date from Order 1000 and include jurisdictional ISO/RTOs) to be able to transfer 30% of their peak electric loads to their neighbors.

The lawmakers compared the current development of the transmission grid to building new highways that crisscross the country every time two towns need to be connected. They say their bill would close current gaps in the transmission network by doing the equivalent of "building new exit ramps off the existing interstate."

"During a heatwave, hurricane or other natural disaster, the last thing you want is for the power to go out. It can be the difference between life and death," said Peters. "There is no reason neighboring electrical grids should not have the capacity to share power during these situations to avoid blackouts. The associated buildout of electric transmission lines would greatly improve reliability and keep costs down for consumers. BIG WIRES will help get clean, reliable energy from where it is produced to where it is used by people, but above all else, it is an American energy security and independence bill."

On top of the reliability benefits, the legislation also would reduce energy costs by allowing

| © RTO Insider LLC

regions where power prices are cheaper to sell into regions where it's more expensive and by allowing all regions to connect new, low-cost resources to the grid.

The bill aims to be technology neutral, allowing all types of generation to connect to the grid and relieve grid congestion where needed. The lawmakers said it would prioritize regional flexibility by allowing the FERC planning regions to decide how they will upgrade their systems.

The bill has a section devoted to ERCOT, which never has had much interconnection with the Western and Eastern Interconnections, giving the Texas PUC authority over its wholesale markets and transmission planning. The PUC "may, at its sole discretion" choose to support the reliability and affordability of the Texas grid by voluntarily complying with a minimum transfer capability equal to a percentage, determined by ERCOT, of its coincident peak load, the bill said.

The two offices released a suite of supportive quotes from clean energy groups, transmission supporters, environmentalists and some former regulators who were on the FERC-State Joint Task Force on transmission, where the idea of interregional transfer capacity was widely supported. (See *States Back FERC Interregional Transfer Requirement*.)

Former FERC Chairman Rich Glick noted that recent years have seen extreme weather test the grid and the bill would help deal with those situations by increasing interregional transfer capability.

"Utility customers are at greater risk of losing access to power during extreme weather events, and they are often forced to pay much more for electricity than they otherwise would with a more efficient electric grid," Glick said in a statement. "Senator Hickenlooper and Congressman Peters deserve credit for elevating this important subject with the introduction of the BIG WIRES Act."

The legislation also won praise from Glick's former colleague from across the aisle, former FERC Chairman Neil Chatterjee.

"By requiring that FERC establish a minimum interregional transfer capability standard, this important legislation will dramatically improve our country's ability to move power between regions where and when it's needed most, enhancing grid reliability for all Americans," he said in a statement.

Former Maryland PSC Chair and FERC-State task force co-chair Jason Stanek also gave the proposal a supportive quote.

"Increasing interregional transmission capacity will be critical to maintaining reasonable utility rates and sustaining a reliable bulk power system," Stanek said. "This bill builds upon recent discussions by the Joint Federal-State Task Force which highlighted the important role that interregional transmission will play as we strengthen our nation's power grid."

Other backers of the legislation include Americans for a Clean Energy Grid, American Clean Power Association, American Council on Renewable Energy, Advanced Energy United, Business Council for Sustainable Energy, Clean Energy Buyers Association, the Electricity Consumers Resource Council, Environmental Defense Fund, Natural Resources Defense Council, Rocky Mountain Institute, the R Street Institute and the Solar Energy Industries Association.

The bill could become part of a broader effort on permitting, which has a chance of passing this year. On Thursday, Senate Energy & Natural Resources Committee Chair Joe Manchin (D-W.Va.) and Ranking Member John Barrasso (R-Wyo.) released a joint statement saying they agreed on the need to change permitting laws and regulations generally.

"We are in agreement that we must act to accelerate our permitting system and are committed to reaching a bipartisan solution that prioritizes American energy security, reliability and affordability," the two said. ■

FERC/Federal News

ACEEE Paper Says Rate Design Can Avoid Higher Bills from Electrification

By James Downing

Without new retail rate designs, full electrification will cause higher overall energy bills for consumers in some regions of the country, the American Council for an Energy Efficient Economy said in a report Thursday.

The success of electrification efforts, which are a major part of addressing climate change, will depend on pairing them with policies that improve equity and lower energy burdens for consumers, according to "*Equity and Electrification-Driven Rate Policy Options*."

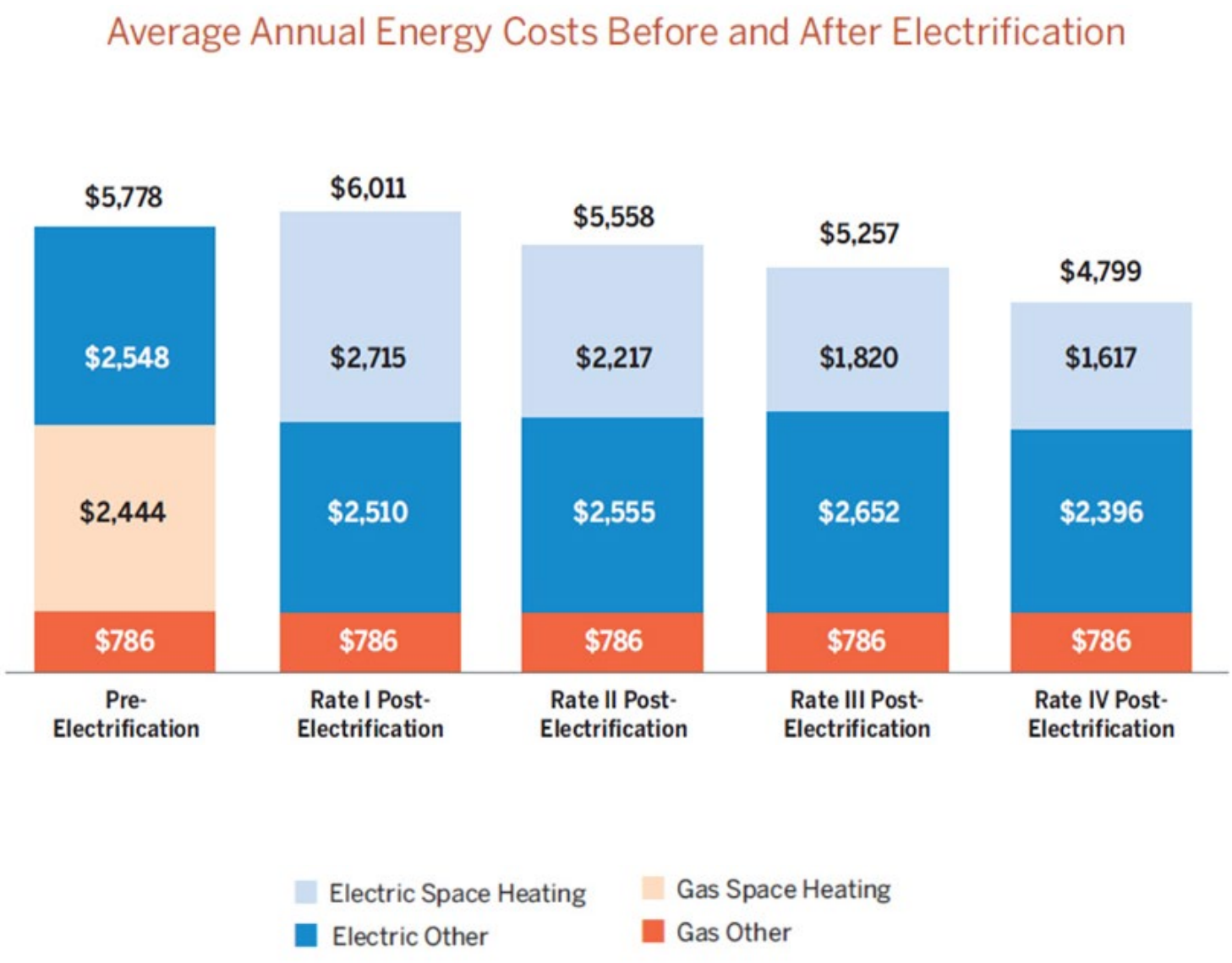
"When electric rates are high, fuel switching can increase the overall energy bill for participating customers," the paper said. "In those circumstances, utilities should find ways to lower the operating costs of electrified appliances, especially for LMI [low- and moderate-income] households."

Electrification involves switching major appliances that use natural gas or heating oil such as furnaces and water heaters and replacing them with devices that run on electricity such as heat pumps.

Earlier research from ACEEE has found that a quarter of U.S. households already have a high energy burden, meaning they spend more than 6% of their income on utility bills. Those bills have been going up lately because of extreme weather and the war in Ukraine.

Heat pumps are more efficient than traditional furnaces that burn fossil fuels, but in some states, electric prices are high enough to negate those savings.

"California and New England are two areas in which electricity rates are significantly above



| *ACEEE*

FERC/Federal News

average; in the rest of the United States, electrification will often produce lower total energy bills," ACEEE said.

Fuel switching could decrease rates, especially if the higher demand happens during times when the grid is not stressed. Other trends, such as the growing use of distributed energy resources, will reduce peak demand, also helping lower rates.

But some regions, including colder areas where electrified heating loads are going to be high, could see higher energy burdens on LMI consumers, the report said.

"It is thus critical to add new electricity demand efficiently; energy burdens could be lowered if electricity rate designs fairly allocate costs and send adequate price signals to inform and give customers opportunities to reduce system costs by changing consumption patterns at high-cost hours," the report said.

Without the policies and rate design, the higher prices in some regions could deter consumers from switching to electricity. The paper evaluated several rate designs but said it was not attempting to provide a comprehensive list of potential solutions.

One option is percentage of income payment plans (PIPPs), which lower burdens for low-income consumers by capping utility bill payments at a set percentage of a participant's income. They keep bills affordable regardless of increases in utility rates, so they can be a complimentary policy to any other rate designs, the paper said.

PIPPs should be coupled with longer-term investments in efficiency and weatherization for low-income homes, which would lower their demand while improving the health and safety conditions of their homes.

Another option is rate designs that enable heating electrification. Rates that offer incentives for customers to change their behavior such as time-varying rates, and ones that are tailored to the operational characteristics of major appliances like heat pumps can cut the impact of fuel switching when areas face higher rates than the national average.

Heat pumps are used most in off-peak hours, so they could benefit from time-varying rates, and they tend to have high load factors most of the time, making their electricity usage more constant and less peaky, so demand-based rights might favor them, all else being equal.

Rate Design Alternatives

ACEEE borrowed some rate designs from an Energy Systems Integration Group *report*, which offered three alternatives that could lower bills when consumers electrify in areas with high power prices.

One, called "Rate II" (Rate I refers to the standard rate), would have lower volumetric charges to offset higher usage with a much higher customer charge to make up for utility costs.

Rate III would have a somewhat higher customer charge and seasonal volumetric charges, as well as peak and off-peak rates. The rates would be slightly higher than the control in the summer months, but favor non-summer off-peak electricity usage while utilities recover their costs from demand during summer peaks.

Rate IV would have a higher customer charge; seasonal supply charges similar to Rate III's, but with a less drastic cost difference; and delivery charges that are only 10% of Rate I's charges. It would add seasonal charges for peak and off-peak periods per kilowatt of demand, with lower charges during the summer.

The introduction of a demand charge, based on consumers' highest monthly use, could be controversial because that use might not actually stress the grid at all if it is not aligned with the system peak demand.

Another option to keep rates reasonable while encouraging electrification is to implement an income-based fixed charge. California is considering the approach after Gov. Gavin Newsom (D) last year signed Assembly Bill 205, which requires the state's Public Utilities Commission to consider a rate with at least three income levels and implement the change by July 2024 while ensuring the change does not hinder electrification and greenhouse gas reductions generally. Historically, California has had very high volumetric rates that include charges for things that do not directly relate to delivering energy, such as wildfire mitigation.

The CPUC has been at work implementing the law, with the state's three major investor-owned utilities submitting a joint plan this April, as did other stakeholders. The average fixed monthly charge for the utilities varies: It would be $53 for Pacific Gas & Electric, $74 for San Diego Gas & Electric and $49 for Southern California Edison, while other parties proposed lower fixed rates.

"Some stakeholders have asserted that higher fixed charges give customers less control over their bills and may be less equitable for customers who do not consume a lot of energy," ACEEE said. "There are also debates over the best way to recover utility system costs through fixed charges." ■

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CAISO/West News

Idaho PUC Declines to Join Western RTO Governance Effort

IPUC Cites Actions, Goals, Creation, Lack of Transparency

By Robert Mullin

The Idaho Public Utilities Commission last week said it will not join with other state regulators in an initiative to lay the groundwork for an independent RTO designed to serve the entire Western Interconnection.

Regulators from Arizona, California, New Mexico, Oregon and Washington proposed the West-Wide Governance Pathway Initiative in July in the face of increased competition for members between CAISO's Extended Day-Ahead Market (EDAM) and SPP Markets+.

The proposal is intended to increase the potential for establishing a single wholesale electricity market that would include the participation of CAISO and build on the ISO's existing Western Energy Imbalance Market and EDAM, for which the ISO recently filed a tariff with FERC. (See *Regulators Propose New Independent Western RTO*.)

Backers of the initiative issued an open *letter* Aug. 29 inviting stakeholders in the Western U.S. and Canada to build "Phase 1" of the effort, which will include "deciding on the form, mission and scope of an entity with independent, West-wide governance." (See *Backers of Independent Western RTO Seek to Move Quickly*.)

But in a *press release* Thursday, Idaho regulators said they had voted unanimously not to participate.

Among their concerns was the conclusion that the initiative "has been less than transparent concerning its creating and funding." The Aug. 29 letter stated that work on the initiative would be backed by "funding derived exclusively from 501(c)(3) sources," an arrangement that would "be evaluated over time and will likely require supplementation as the workload intensifies."

Idaho PUC President Eric Anderson | *Idaho PUC*

Western utility commissioners discussed the West-Wide Governance Pathway Initiative at CAISO's EDAM Forum in Las Vegas on Aug. 30. From left: Stacey Crowley, CAISO; Milt Doumit, Washington UTC; Alice Reynolds, California PUC; Letha Tawney, Oregon PUC; Kevin Thompson, Arizona Corporation Commission; Gabriel Aguilera, New Mexico PRC; and Hayley Williamson, Nevada PUC. | *© RTO Insider LLC*

The Idaho commissioners said also that "there is no evidence that the initiative's goal of independent governance is feasible without changes in California's legislation," an issue which has long impeded CAISO's efforts to expand into the wider West.

The regulators additionally called the initiative's goal of seating a board of directors by January 2024 "premature and unrealistic" and said that "at its core, the initiative presumes economic benefits for Western states without justification or specifics."

"As always, the IPUC respects other commission, state and stakeholder decisions concerning participation with the initiative," Idaho PUC President Eric Anderson said in the release. "However, given the IPUC's concerns, the inherent flaws in the creation of the initiative and the initiative's current actions and goals, the IPUC does not see a viable path forward for the initiative or that participation would result in any specific net economic benefits for Idaho customers."

The governance initiative was the key topic during a panel discussion among utility commissioners at CAISO's EDAM Forum in Las Vegas on Aug. 30. The commissioners acknowledged that Phase 1 would operate outside of any existing organization or decision-making process, and they asked regional stakeholders to provide feedback on how to structure the process.

Speaking on the panel, California Public Utilities Commission President Alice Reynolds said the effort is intended to set aside the problem of CAISO's governance and determine what an independent entity "needs to look like."

During a separate panel at the forum, Idaho Power CEO Lisa Grow lauded CAISO's efforts in developing the EDAM but questioned the need for the West to create a full RTO in the near term.

Grow said that, unlike utilities in Colorado and Nevada, Idaho Power doesn't "have legislative or PUC-mandated things that we have to do towards an RTO, so we can kind of watch how this goes." ■

CAISO/West News

CAISO Might Scrap Policy Catalog, Start from Scratch

By Elaine Goodman

CAISO is looking at scrapping a catalog of about 60 proposed policies, which include many stakeholder suggestions, saying the document has become "unwieldy" and it might be better to start over from scratch.

The ISO's so-called "policy catalog" lists current, planned or potential policy initiatives aimed at enhancing its markets. The catalog is used in crafting CAISO's policy roadmap, which details what it intends to take on over the next three years.

The policy catalog and roadmap were discussed Sept. 12 during a meeting of the Western Energy Imbalance Market (WEIM) Regional Issues Forum (RIF).

CAISO updates the policy catalog twice a year; stakeholders can submit suggestions at any time. With about 60 policy initiatives, the latest *catalog*, released in March, "has proven a little bit unwieldy," said Becky Robinson, the ISO's principal economist and director of market strategy and governance.

"There's often more in the catalog than there is bandwidth to take on," Robinson said.

The ISO is asking the RIF for ideas to make the catalog "more meaningful and relevant," she said.

One option would be to consolidate the existing catalog, with stakeholders grouping and prioritizing the initiatives. The second option would be to start over with a "clean slate." Stakeholders could submit new proposals or re-submit earlier suggestions.

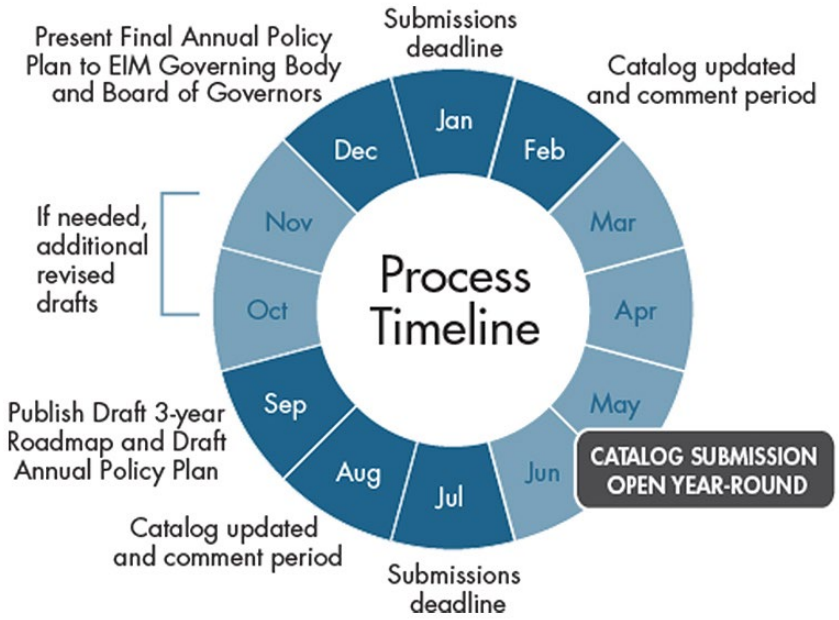
In going from the catalog to the policy roadmap, CAISO would like to coordinate the plan with its strategic goals, resources and other planning processes.

RIF's Expanded Role

Discussion of the policy catalog and roadmap comes as the RIF is expanding its role at CAISO.

The RIF is an independent, self-governing body that includes stakeholders from various sectors across the Western Interconnection. It provides feedback on WEIM-related issues.

RIF's enhanced role was mentioned in January, when the WEIM Governing Body and ISO Board of Governors approved changes recommended in the WEIM Governance Review Committee's Phase 3 final proposal. (See *CAISO Approves Day-ahead Market for Western EIM*.)



CAISO and its Regional Issues Forum are discussing potential changes to the process for creating a policy catalog and roadmap. | *CAISO*

In its *proposal*, the committee "encouraged the RIF to continue its transition from a role that was largely educational at its outset to one that is capable of providing advisory input as well." The committee urged CAISO staff to support the transition.

Josh Walter, who chairs the RIF, said the forum's evolution "provides the opportunity to have a more meaningful impact on the WEIM's Governing Body and their decision-making."

"This new role allows the RIF to discuss and opine on active stakeholder initiatives, provide direct input to the Governing Body on decisional issues independent of CAISO staff and serves as an important resource in market development and enhancement decisions," Walter told *RTO Insider*.

During last week's meeting, WEIM Governing Body member Anita Decker said she's looking forward to watching "this evolution of the RIF."

"I really want to reinforce that the RIF really is part of the WEIM governance," Decker said. "We want to hear from you."

Noting that the Governing Body already is "highly supportive" of the RIF, Meg McNaul, the forum's vice chair, pointed to two immediate goals for the group. One goal is to help stakeholders communicate their policy positions to CAISO through the existing process.

The second goal is a new endeavor for the RIF. The group will organize a roundtable discussion on CAISO's policy catalog and roadmap so stakeholders can weigh in on prioritization of initiatives. The first roundtable is expected to take place early next year.

The RIF also has a longer-term role, McNaul told *RTO Insider*.

"As the EIM evolves, the RIF can play an important role in contributing to the regional dialogue on topics of importance to the stakeholder community, as shown by this week's in-depth discussion of price formation topics," she said.

What's in the Catalog

Proposals in CAISO's policy catalog are those that would require a stakeholder process and typically result in ISO tariff changes.

The latest version of the catalog lists, "Initiatives Currently Underway and Planned," which include enhancements to resource adequacy, day-ahead markets, price formation and energy storage modeling.

Among its 57 "discretionary initiatives," the catalog lists pumped storage with multiple pumping levels, balancing-area-authority islanding of internal regions, and a potential WEIM-wide transmission rate. ■

CAISO/West News

NW Stakeholders Divided on BPA Timeline for Day-ahead Decision

By Robert Mullin

Northwest electricity sector stakeholders last week expressed divisions over the Bonneville Power Administration's plan to pursue an aggressive timeline for deciding whether to join CAISO's Extended Day-Ahead Market (EDAM) or SPP's Markets+.

BPA's decision will carry significant weight in the Northwest, where the federal power marketing agency controls more than 22 GW of mostly hydroelectric generation, operates 70% of the transmission grid and serves dozens of large customers, including the region's extensive network of publicly owned utilities.

Its choice also could influence the decisions of system operators elsewhere in the West. Supporters of the accelerated timeline seem to be hoping for such an outcome, not only to boost the clout of BPA but of the Northwest in general.

"We've been followers for far too long, and we actually have a chance here to be a leader — and, yes, that means sticking our neck out there a little bit," Shawn Smith, managing director of energy resources at Chelan County (Wash.) Public Utility District, said last week at a BPA public workshop to discuss the day-ahead market decision. Smith was referring to a view shared by many in the region that public power entities became involved in CAISO's Western Energy Imbalance Market (WEIM) too late to hold much sway in its initial development.

"I think it's really important for BPA to come out and express where they're leaning [in] Q1 of next year," said Laura Trolese, director of Western markets strategy at The Energy Authority, which provides energy market services to public power entities.

Trolese noted the region is facing a wave of changes related to resource adequacy, state climate policies and organized electricity markets.

"It's moving at a pace that we've never seen, but we have to start making decisions and move forward with all of the uncertainty and figure things out as we go. We just can't wait for everything to be figured out before BPA makes a decision," she said. "At that point, there's no decision to make, so I really appreciate these guys stepping up and starting this process."

Michael Linn, director of market analytics at the Public Power Council, acknowledged that SPP has not yet completed a Markets+ tariff and many issues related to the initiative remain outstanding. (The RTO expects to file with FERC in early 2024.)

"But we know about governance; we know

BPA transmission line near the Bonneville Dam | © RTO Insider LLC

CAISO/West News

about some price formation. And, frankly, the way Bonneville signals or leans may ultimately kind of determine a path forward for either of these markets," Linn said. "So I think it's important to acknowledge that … indecision at this point is a decision and it almost is a forfeiture of our leverage as a region [that has] a lot of transmission and hydropower."

'Crucially Important'

Other meeting participants questioned the need for such speed.

Speaking on behalf of the Western Public Agencies Group, which represents Oregon and Washington public utilities involved in BPA proceedings, Lea Fisher contended that BPA's process for joining the WEIM and the Western Power Pool's Western Resource Adequacy Program (WRAP) seemed more "substantive" than the process envisioned for choosing a day-ahead market. Fisher pointed out that BPA has proposed a seven-month process consisting of five workshops, compared with a 14-month process with 10 workshops for the WRAP and a five-phase, three-year process for joining the WEIM.

"You can see how the process BPA has currently outlined for the decision to join a day-ahead market seems light in comparison," she said, asking whether there would be another "follow-on" process after the agency made its determination.

Matt Hayes, BPA program manager and policy analyst, said the seventh-month process would be "analogous" to the agency's initial process for deciding to join the WEIM, which would be followed by a "much longer" process related to implementation.

But chief among the skeptics of BPA's timeline was Fred Heutte, senior policy associate with the Northwest Energy Coalition (NWEC), who said the "big question" was the uncertainty around FERC's responses to the EDAM and Markets+ tariff filings. Heutte said the EDAM filing was "very complete," but took five years to put together, while "much, much less time" has been spent on developing Markets+.

"And it's really evident sitting in some — not all — of the Markets+ meetings, that there are a lot of key pieces that haven't yet been hammered down," he said, adding that NWEC is "feeling a bit of unease about the schedule."

"I think you're just articulating the challenge and sort of the misery of what my group deals with on a daily basis," Russ Mantifel, BPA director of market initiatives, said. "But other entities are making decisions, right? But Bonneville is not in a vacuum, where we get to have self-determination over exactly what all of our options are going to be. And I've never delivered what has been considered to be good news. I've never run a process where people thought we had enough time."

Heutte said BPA faces a "crucially important" choice.

"Among other things, it's a choice to leave the EIM after taking so long to get into it and realize some real value from it. And the big thought that I have right now is, look before we leap," he said.

'Not Equally Distributed'

If NWEC's reservations about the timeline are colored by a concern that BPA could stymie the potential for a single West-wide electricity market by choosing Markets+ over EDAM, then BPA officials did little to assuage that concern last week.

Industry sources not authorized to speak on behalf of their organizations have told *RTO Insider* that BPA is favoring Markets+ — in part because of an in-depth economic study commissioned by the Western Markets Exploratory Group to ascertain Western market benefits.

The sources said the study, which has not been released to the public, shows that, in a single market, a disproportionate share of the benefits would flow to California, while a two-market solution would provide greater financial benefits to BPA and the Northwest at large.

Mantifel spoke around the specifics of the study but appeared to confirm that assessment.

"The results are complicated … and identifying who receives which benefits is also an important part. Societally, a broad footprint produces more diversity, more optimization [and] produces more benefits, but I think they're not equally distributed," he said.

BPA plans to hold a call on Oct. 23 to discuss the "quantitative results" of the study related to the agency, he said.

During the meeting, Mantifel also praised BPA's experience in working with SPP during the Markets+ design process.

Responding to a question about whether BPA preferred SPP's stakeholder-driven process for dealing with market initiatives over CAISO's staff-led approach, he said, "I think we've really enjoyed our experience with the SPP process. Being engaged in it is difficult; sometimes it feels messy. But that process, I think, is a good representation of how representative that organization is." ■

ERCOT News

ERCOT Walks 'Balancing Act' During Recent EEA

Unusually Hot Summer, Low Wind, Solar Down-ramp Contributed

By Tom Kleckner

Newly minted ERCOT COO Woody Rickerson told Texas regulators Thursday that this month's Level 2 energy emergency alert was a necessary "balancing act" to protect ERCOT's system equipment and to prevent load shed.

"I think the operations team did a really good job in very unusual circumstances," Rickerson said in reviewing *staff's report* of the Sept. 6 event during the Public Utility Commission's open meeting. "It's not something you see every day, but they were able to balance the two things and maintain reliability."

Rickerson told commissioners several factors contributed to low power reserves that led to a drop in system frequency from 60.1 Hz to 59.9, the most significant being an "unusually" hot summer that has resulted in "abnormally" high demand. (See *ERCOT Voltage Drop Leads to EEA Level 2*.)

He said declaring a Level 2 EEA that bypassed Level 1 allowed ERCOT to deploy its responsive reserve service, or spinning reserve, and to interrupt power to some large industrial users. The alert was issued at 7:25 p.m. as solar power began ramping down in the evening after the ISO had already called on most of the ancillary services it relies upon during tight operating conditions.

The grid operator normally calls a Level 2 alert when its physical responsive capability (PRC) is less than 1,750 MW and not expected to recover within 30 minutes. Rickerson said the PRC had dropped to 2,104 MW at the time of the frequency decay.

"We suspect that the PRC number was not accurate," he said. "We're looking for why ... there were several possible reasons."

Rickerson, who was promoted to COO on Sept. 1, said staff are conducting a more detailed analysis that will be shared with the PUC.

"We had relatively low wind that day, we had a congestion problem that caused us to curtail some generation, and all this occurred right in the middle of a solar down-ramp ... so all these things were moving at the same time," he said.

Thermal outages were just over 6 GW — "in line" with the summer's forced outages, according to ERCOT's report — during Sept. 6's late afternoon and early evening hours.

However, much-needed power from South Texas wind farms was restricted by an overloaded 345-kV transmission south of San Antonio. ERCOT was forced to order a manual curtailment of 1,590 MW of generation from the South to avoid "significant consequences" to grid reliability.

ERCOT's board recently approved a transmission project it said would help address congestion in South Texas. The PUC has not yet considered the project for approval. (See "San Antonio Tx Projected OK'd," *ERCOT Board of Directors Briefs: Aug. 30-31, 2023*.)

Commissioner Jimmy Glotfelty asked whether the transmission line was dynamically rated and whether it was rated accurately. Rickerson responded that ERCOT relies on transmission providers, who make their own line ratings.

"The new San Antonio line will help, but the biggest thing that would help would be generation north of San Antonio. That's the remedy," Rickerson said.

Glotfelty also asked Rickerson to provide more information on thermal outages in North Texas, saying, "There's a lot more to look under the hood here."

Rickerson promised ERCOT's next report will "beef up" the generation limitation.

"We always look at these types of operational incidents as opportunities, places to sharpen our tools and improve our procedures," he said. "There are some things we can change and procedures to make these things more rote for the operators. We are going through a phase where our grid is not the grid we had in the past, and we're going to have new challenges. Our procedures and processes will need constant tune-ups to keep up."

PUC Files Proposed Rulemakings

The commission approved for publication a rulemaking that creates the committee overseeing the *Texas Energy Fund* loan program created during the 2023 legislative session (*55407*).

The rulemaking is a result of *Senate Bill 2627*, which sets aside billions for new dispatchable generation, backup power and upgrades in ERCOT and the non-ERCOT portions of Texas. Non-ERCOT utilities can use these funds to modernize or weatherize facilities and for resiliency improvements. Energy storage facilities are not eligible.

ERCOT COO Woody Rickerson briefs the PUC on the recent EEA Level 2 event. | *Admin Monitor*

SB2627 requires the PUC to evaluate loan applications based on service quality, operational efficiency, a history of in-state operations, and other factors. The loans will have a 3% interest rate and 20-year terms.

The Texas Backup Power Package Advisory Committee, comprising three to nine members appointed by the PUC's executive director, will be responsible to recommend the grants' and loans' criteria to the commission.

Commission staff are holding a workshop on the loan program this *Thursday*.

Texas voters will have an opportunity to approve or reject the program during the Nov. 7 statewide elections.

The PUC also approved for publication rulemakings that:

- set up an emergency pricing program activated when ERCOT's average system-wide energy price has been at the $5,000/MWh high system-wide offer cap for 12 hours within a rolling 24-hour period. The program's emergency offer cap will be set the low systemwide offer cap of $2,000/MWh (*54585*).
- create annual resiliency plans to be filed with the PUC by transmission and distribution service providers (*55250*).
- direct transmission and distribution utilities to perform circuit-segmentation studies and determine whether load shed can be managed more effectively (*55182*).

The proposals are published on the PUC's website and in the *Texas Register* and are unable to be adopted as final rules for 30 days. A public comment period is held during that time. ■

ISO-NE News

ISO-NE Recommends Delaying FCA 19

Clean Energy Stakeholders Weigh in; RTO Hopes to Vote in August 2024

By Jon Lamson

ISO-NE is recommending a one-year delay of Forward Capacity Auction 19 (FCA 19) to implement resource capacity accreditation (RCA) changes and determine whether to move to a prompt and seasonal capacity market, the RTO told the NEPOOL Markets Committee last week.

Since June, the RTO has been taking stakeholder feedback on the best path forward for FCA 19 following a delay caused by a software issue in the RCA process, as well as on a potential move to a prompt and/or seasonal market. (See *NEPOOL Debates Options for FCA 19*.) FCA 19, scheduled for February 2025, corresponds with Capacity Commitment Period 19 (CCP 19), which runs from 2028 to 2029.

After laying out a series of options in previous meetings, ISO-NE *endorsed* "option 2A," which would provide some extra time to finish the RCA process for FCA 19 and further discuss the merits of capacity market changes.

Chris Geissler of ISO-NE said this option "recognizes the importance of simultaneously implementing a revised capacity accreditation framework that coincides with the elimination of the minimum offer price rule (MOPR) for FCA 19."

The RCA *project* is intended help the organization "more accurately reflect resource contributions to resource adequacy." ISO-NE has expressed its desire to time the implementation of these changes with the scheduled elimination of the MOPR. (See *FERC Accepts ISO-NE's MOPR Transition Plan*.)

"While some stakeholders prefer maintaining the status quo (FCA 19 without RCA), the ISO is concerned it may not adequately prepare the region for the changing resource mix and expected clean energy system," Geissler said.

Clean Energy Stakeholders Weigh in

A range of clean energy stakeholders outlined questions, comments and concerns about the potential capacity market changes. The comments highlight the lack of consensus among various renewable energy groups, along with uncertainty about how a prompt seasonal market would affect resources.

Deepwater Wind Block Island, a subsidiary of Ørsted, *supported* implementing RCA changes and moving to a prompt and seasonal capacity market for CCP 19, writing that the move would limit uncertainty for long-term investments while helping reliability. The company added that ISO-NE's *preliminary analysis* of the RCA design indicated it would enable offshore wind resources to clear more capacity.

"The combination of incorporating RCA and the removal of the MOPR in CCP 19 will enable offshore wind resources the opportunity to compete with other existing resources on a more even playing field," wrote Eric Wilkinson of Ørsted. "Ratepayers will benefit from these changes by increasing the amount of capacity being provided from clean energy resources."

In contrast, representatives of New Leaf Energy and SYSO Inc. expressed their opposition to delaying the auction and supported holding it under the current rules without RCA changes. The companies *argued* that any delay of the auction would introduce uncertainty and hurt new resources looking to connect to the grid, because new generators rely on the forward capacity market to secure capacity rights.

"Postponing the FCA without a replacement process for generators to secure these rights will prevent new resources from knowing whether they can access the capacity market, threatening the financial viability of these projects, as well as the pace of the clean energy transition," the memo said.

The companies added that delaying the auction could lead to a backlog of projects in the interconnection queue once a new process is implemented.

ISO-NE told the Markets Committee it might need to separate the interconnection process from the capacity market to comply with FERC Order 2023 no matter which capacity market design ultimately is chosen (*RM22-14*.) (See *FERC Updates Interconnection Queue Process with Order 2023*.)

"To address FERC Order 2023, the ISO will be required to migrate to a single annual cluster process, with equal queue positions and shared upgrade cost allocation within the cluster, for studying new interconnections," ISO-NE *noted*.

In an August *letter* to ISO-NE, Advanced Energy United, which advocates for clean energy policies on behalf of its member companies, wrote that there are significant "information gaps" surrounding the effects of ISO-NE's stated options for CCP 19 on new resources, retirements, the RCA process and subsequent capacity commitment periods.

"We do not feel stakeholders can make informed decisions without further explanation addressing these information gaps," Advanced Energy United wrote. "While we appreciate the time constraints driving ISO to move quickly to land on a preferred path forward, we believe the significance of the decision necessitates a fulsome exploration of the implications of each pathway, and we are not yet satisfied that ISO-NE and NEPOOL have completed such an exploration."

Aleks Mitreski of Brookfield Renewables expressed concerns in a *presentation* to the Markets Committee on Sept. 12 relating to the entry and exit of resources, along with transmission upgrades. Mitreski added that some of the issues with the forward capacity market likely could be fixed without overhauling the entire market design.

Next Steps

ISO-NE proposed making an initial FERC filing by the end of this year to delay the auction, followed by another filing next year to either finalize the one-year delay including the RCA changes or to create a new schedule to implement a prompt auction for FCA-19, which would be held in 2028.

ISO-NE will present the detailed tariff revisions at the October MC meeting, followed by a November MC vote and a Participants Committee vote in December.

Also at the October MC meeting, ISO-NE will resume discussion on the RCA proposal, which likely will extend into next year. The RTO is targeting an August 2024 vote on the proposal.

ISO-NE also has *commissioned* the Analysis Group to conduct a qualitative and quantitative analysis of the potential effects of moving to a prompt and/or seasonal market. The consulting firm will need to work on a tight schedule, as ISO-NE expects it to present to the MC the scope of its work in October, the methodology in November and results in December. ■

MISO News

MISO Said It Could Have Employed Wait-and-see Approach for August Emergency

Peak was Lower Than Expected, But CEO Cautions Against Hindsight Judgment

By Amanda Durish Cook

MINNEAPOLIS — MISO officials last week said they probably could have held off their decision to call a summertime emergency in late August.

MISO declared its lone summertime emergency and instated maximum generation procedures Aug. 24. (See *MISO Calls 1st Summertime Emergency amid Systemwide Heat Wave*.) However, the 123-GW peak under the widespread heat dome wasn't the 127-GW peak MISO anticipated that morning. It also didn't amount to the grim possibility MISO *warned* about ahead of summer, where it could exhaust all of its emergency reserves.

MISO's summer peak demand of 125 GW interestingly arrived Aug. 23, a day before MISO called the maximum generation event. Intense heat struck multiple major cities in MISO simultaneously Aug. 23-24.

During a Sept. 12 Markets Committee of the Board of Directors meeting, Executive Director of System Operations Jessica Lucas said on Aug. 24, MISO worked to de-commit previously signed-on resource as load outlooks improved during the day. Lucas said in hindsight, MISO could have waited longer to make resource commitments to make sure they were necessary.

MISO CEO John Bear said it's important to judge control room operators on what they saw in the moment and not by perfect hindsight. Multiple MISO executives said load forecasting and unit commitment during extremes is difficult, especially when fuel supply issues, low wind and other environmental limits related to heat hinder resource performance.

"We walked into that day knowing we had a high load forecast," Executive Director of Market Operations J.T. Smith said.

Smith said a more sophisticated forecast might better anticipate coming "cloud cover in Detroit" so operators aren't forced to commit as many resources on the mornings of pervasive heat waves.

Lucas said it was the hottest summer — and resulted in the highest demand — in MISO South since its integration in 2013. Southern demand hit a new high of 35 GW on Aug. 23.

"This summer was marked by five major heat waves," Lucas said.

Markets Committee of the MISO Board of Directors underway | © *RTO Insider LLC*

Despite that, Lucas said MISO used its emergency procedures only once. She said average temperatures in MISO Midwest shook out about normal, while MISO South was above normal.

Independent Market Monitor David Patton said MISO's forecast model overestimated load between 2-8 GW on the hottest days in July and August. He said the model may not be picking up voluntary actions of MISO market participants to reduce load and behind-the-meter solar generation that likely spikes as demand soars on hot days.

Patton warned MISO about creating "artificial surpluses" during hot days that mute real-time prices. He reminded MISO leadership that MISO has short-term reserves and often experiences a "wave of imports" from neighboring regions when its prices rise. He urged them to let MISO's market dynamics do more of the lifting in a heat dome.

However, Patton lauded MISO operators for having the foresight to cancel resource commitments Aug. 24 when it became clear they would be unnecessary. He said the move saved MISO customers about $1.6 million, though some MISO suppliers were unhappy because they purchased gas in anticipation after being selected to generate.

"It's much better that you do that instead of ride it out and have more resources than you need," Patton said.

Patton urged MISO to hold out longer on resource commitment decisions and declaring emergencies. He said MISO shouldn't allow its market "to work against us" in tight operating conditions. Committing so many resources that prices stay low at about $45/MWh might lead some resources to export their output, Patton said.

MISO Director Barbara Krumsiek asked if MISO would have enough transmission capability if "decisions were made differently" and MISO were more confident in imports. Patton assured her MISO is flush with import capability.

Patton also acknowledged that for control room operators, overseeing the situation in real time is much tougher than delivering after-the-fact analysis.

"I can sit here and say, 'have faith in the markets,' but when you're an engineer sitting in the control room, that's a hard thing to accept," Patton said.

MISO News

"Thank you! Thank you for saying that; I don't think I've ever heard you say that," MISO Director Phyllis Currie said, eliciting laughs from the audience.

MISO again prepared for near-record electricity demand and tight conditions this month as a lingering September heat wave settled on its Midwest region. It enacted a hot weather alert for its North and Central regions Sept. 3-5 when temperatures again exceeded 95 F in some parts of MISO Midwest. The grid operator handled those days without emergency procedures.

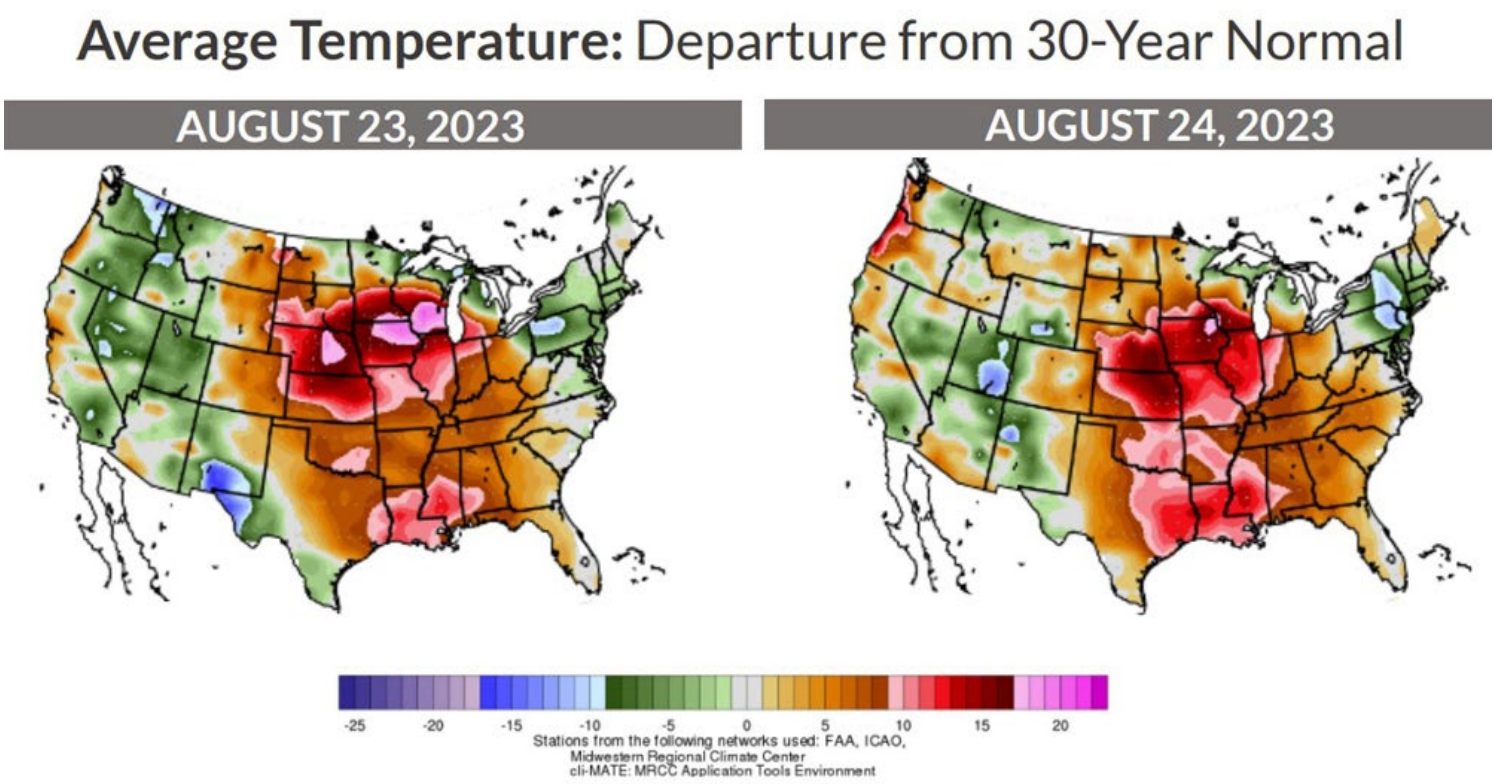
Executive Director of Market and Grid Strategy Zak Joundi said until recent years, MISO and members have been "fortunate" to preside over smooth operations and manage them with simpler market tools. However, he said a multitude of renewable resources and increasingly unstable weather is poised to further drive volatility and riskier operations.

"The world that we are operating is a lot more complex, so to maintain the reliability we've become accustomed to, we will need to adjust our markets and processes," Joundi told board members.

Joundi said the weather years MISO has experienced recently are more indicative of what's to come and should be assigned more weight in loss of load prediction modeling than other historic years.

Smith said MISO has a goal to set dynamic reserves, so the markets determine a greater share of the operations, rather than control room operators.

Smith said MISO is headed into a future where operators can't feasibly consider all the "various inputs" to mitigate risk. He also said MISO is conducting "toes in the water" testing of machine learning in its markets to forecast risk ■.



Heat map of departures from 30-year normal temperatures Aug. 23-24 | *Midwestern Regional Climate Center*

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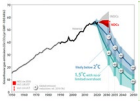
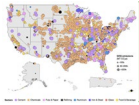


UN Report Calls for Quicker Global Emissions Reductions — NetZero Insider



DOE Reports Examine the Difficult Job of Industrial Decarbonization — NetZero Insider

NERC Seeks Comment on IBR Registration Proposals — ERO Insider

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

MISO News

MISO: Reliability Risk Upped by 49 GW in Approved but Unbuilt Generation

Supply Chain Partly to Blame; Longer Timelines Likely

By Amanda Durish Cook

MINNEAPOLIS — MISO's quarterly Board Week explored the reasons behind the RTO's growing number of generation projects that have the stamp of approval to connect to the system but remain unbuilt.

49 GW Greenlit but Unfinished

MISO said many of its new resources that have struck generator interconnection agreements are beset by delays and cancellations, "mostly driven by build-related issues." It said those lost and paused resources increase risk for a "future capacity or reliability attributes shortfall."

By MISO's *count*, 49 GW approved through its interconnection queue are awaiting construction, with an average delay to commercial operations of more than 650 days.

Scott Wright, MISO | © *RTO Insider LLC*

"That's nearly 50 GW. This is pretty sizable. … This is a very pressing situation. We need to get iron in the ground. That's what needs to happen," Executive Director of Resource Planning Scott Wright said during a meeting of the Board of Directors' System Planning Committee on Sept. 12. He added that MISO is negotiating new GIAs all the time and the postponed gigawatt amount is certain to rise by year-end.

Wright said MISO's plan to place an annual megawatt limit on project proposals, collect higher entry fees, enact escalating penalty charges and require developers to prove they have secured land will make for more certain generation projects that ultimately will mitigate long-term risk. (See *MISO Sticks with MW Caps, Higher Fees to Pare Down Queue Requests*.)

"With all the capital flowing in, it's not hard to imagine a queue that's 500 GW," Wright said. He added MISO needs to be more selective about the projects it allows in to produce good network upgrade studies and approve projects that are a sure thing.

But Wright said incoming, mostly renewable generation likely won't fare well in terms of accredited capacity. He also said EPA's proposed carbon rule stands to pull the plug on "tens and tens" of gigawatts.

MISO has said EPA's proposed emissions rule for fossil plants would supercharge retirements so they outpace the commercialization of new technologies like green hydrogen and carbon capture. (See *EPA Power Plant Proposal Gets Mixed Reception in Comments*.)

"Thank you so much for that very calming discussion," MISO Director Mark Johnson joked.

MISO members at a Sept. 13 meeting of MISO's Advisory Committee were light on answers as to how to get the 49 GW online sooner.

"These are not speculative projects. We ran into the pandemic and supply chain issues," Invenergy's Arash Ghodsian said.

Wisconsin Public Service Commissioner Tyler Huebner seconded that view. He said developers ran headlong into the pandemic, and then a federal investigation into solar panels hampered new capacity.

"It has been a compounding of issues on the solar side in particular," Huebner said.

"It's incredibly challenging to build out new infrastructure, new power plants," Invenergy's Eric Thoms added.

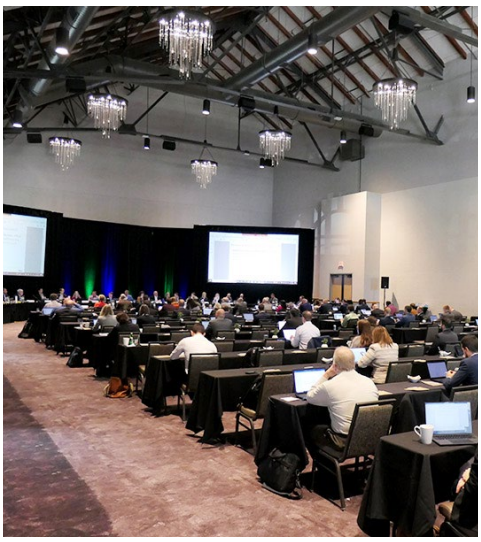
North Dakota Public Service Commissioner Julie Fedorchak suggested MISO and members simply allow more time to develop generation. She said special interest groups and landowners are getting more vocal in proceedings at state commissions and commissioners are having to extend timelines to hear them out.

"I think we need to just bake in more time. Not to give up, but just be realistic," she said.

Ameren's Jeff Dodd seconded that longer timelines probably are the new reality. He said there's more "fatigue" these days among landowners who are asked to host infrastructure.

Clean Grid Alliance's Beth Soholt asked MISO for more data behind the delays on new build capacity, including locations and whether local communities are opposing projects. However, Soholt said transmission construction must catch up to meet the needs of generation developers.

"We have a transmission problem — we're working on it — but we did have a 10-year lag between the Multi-Value Projects and [the first long-range transmission portfolio]. So, we have a backlog in some of the generation projects that want to connect," she said.



MISO's Advisory Committee in session Sept. 13 in Minneapolis | © *RTO Insider LLC*

Solholt said it's important the nearly $2 billion Joint Targeted Interconnection Queue (JTIQ) portfolio of 345-kV lines is built to ease the queue backlog. She also said MISO's Environmental sector prefers members not simply leave fossil generation operating on the system for "longer and longer."

WEC Energy Group's Chris Plante said though MISO can complete scores of generator interconnection agreements, some projects still are "conditional until the transmission reinforcements are there."

"I want to make sure we have a heightened sense of urgency," MISO CEO John Bear said a day later at the board meeting. He said MISO is up against a wave of generation retirements and similarly tapering reserves at PJM and SPP, which means the RTO won't be able to rely on imported power from neighbors in the future.

"We're going to have to take care of ourselves," he said.

Bear said while MISO can export on windy days, it often runs into trouble when wind drops off. He advocated for "dispatchable, long-duration assets" on the system. He said though MISO remains fuel neutral, "we're big fans of reliability." ■.

MISO News

MISO: Expect More Expensive Annual Transmission Packages

Directors Ask About Continued Large Investments, Reason

By Amanda Durish Cook

MINNEAPOLIS — MISO's lead planners last week told their Board of Directors that more expensive annual Transmission Expansion Plans (MTEPs) will become the norm, saying MTEP 23's $9.4 billion package is a sign of future scattershot load growth in the footprint.

MTEP 23 contains 578 projects at $9.4 billion, more than doubling MTEP 22's investment. (See *MTEP 23 Catapults to $9.4B; MISO Replaces South Reliability Projects*.)

Senior Director of Transmission Planning Laura Rauch acknowledged that MTEP 23 is the largest MTEP cycle in MISO's history that doesn't include long-range transmission plan (LRTP) projects or Multi-Value Projects.

During a meeting of the MISO Board of Directors' System Planning Committee on Sept. 12, Rauch said most MTEP 23 projects are needed for reliability amid "localized load growth rather than bulk increases to load." She characterized the bump in load as "spot load growth."

MISO Director Nancy Lange asked whether the RTO anticipates "these lumpy, large investments" in MTEP cycles into the future.

Rauch said MISO members have indicated large industrial and commercial load additions will persist. She said MISO planners are expecting more economic growth in the footprint and sizable demand from new data centers and green hydrogen facilities.

MISO Director Barbara Krumsiek asked if funds from the Inflation Reduction Act are behind the jump in transmission needs.

MISO's Laura Rauch listens during the Sept. 12 System Planning Committee of the Board of Directors meeting. | © RTO Insider LLC

"It's such a substantial leap. Has it been long in the making or recent?" she asked.

Rauch said the upswing in spending appears to be occurring independent of government funding.

MISO Director Mark Johnson said despite the billion-dollar costs of two MTEP 23 projects, the projects differ from LRTP projects because they're meant to be in service within three years, not the approximate decade allotted for the long-term planning.

Rauch said MISO remains "firmly committed" to recommending LRTP projects in MISO South despite the large amount of MTEP 23 investment in the region. She said the MTEP 23 projects don't "preclude" separate, future solutions for long-term transmission needs in the South. ■.

MISO News

MISO Board of Directors Briefs

Members to Vote on Whether to Place Former Ford Exec on Board

By Amanda Durish Cook

MINNEAPOLIS — MISO's Board of Directors next year likely will include a former Ford executive, directors announced last week.

MISO's Nominating Committee interviewed eight candidates and two incumbents to fill three open slots on the board beginning in January. Current members Jody Davids, Theresa Wise and Robert Lurie are rounding out three-year terms and were up for re-election.

Davids ultimately decided not to seek a second term on the board. She joined the board at the beginning of 2021.

Jeff Lemmer | *Jeff Lemmer via LinkedIn*

The opening likely will be filled by Jeff Lemmer, the former vice president and CIO at Ford Motor Co.

The Nominating Committee — comprising two MISO members and three MISO directors — worked with search firm Russell Reynolds to select candidates for interview.

MISO Director Phyllis Currie said while at Ford, Lemmer supervised the inclusion of EVs in production.

Otherwise, current directors Wise and Lurie will stand for election.

MISO members now have about a month to vote electronically on the new appointment and incumbents; candidates must earn a majority of member votes to be confirmed.

MISO and its board still must decide which directors it might retain for an extra term through a waiver that allows them to stand an additional three-year term beyond the three-term limit.

The board has said it has multiple directors who will hit their three-term limit beginning next year and it may use waivers to preserve institutional knowledge. (See "Waivers May be Necessary to Retain Directors Past Term Limits," *MISO Board of Directors Briefs: March 23, 2023*.)

MISO's board consists of nine independent directors and the RTO's CEO. The independent directors are limited to three three-year terms, but its bylaws allow some board members to serve an additional term under certain circumstances.

Directors Currie and Mark Johnson were re-elected to their final terms that began in 2022. They will hit their three-term limit at the end of 2024. Todd Raba, H.B. "Trip" Doggett and Barbara Krumsiek also were re-elected late last year. Their final terms conclude at the end of 2025.

Finally, the board selected Raba, the current board chair, to continue leading the board in 2024. Raba said the MISO board will remain his only professional commitment.

"Basically, I'm all in," he said.

MISO Pursues $400M Budget for 2024

MISO says it likely will spend nearly $400 million over 2024, continuing a trend of budget increases year-over-year.

MISO is proposing a $370 million 2024 operating budget, which contains a nearly 15% increase in base operating spending over 2023. It also is eyeing approximately $27.3 million in capital spending.

MISO likely will up its $0.44/MWh tariff rate for members to $0.47/MWh next year.

MISO CFO Melissa Brown said increases to the member rate remain below nationwide inflation trends.

Brown said MISO's total increase for 2024 is 9.1%, higher than the estimated tariff rate increase of 7%. The extra percentage over the tariff rate is from revenues MISO receives from the studies it performs for its generator interconnection queue and fees it collects to evaluate competitive transmission project applicants.

MISO said much of the jump in base operating expenses boils down to hiring and retaining employees.

The RTO said it soon will add nine new employees specializing in system planning and five new staff members to concentrate on MISO's ongoing market redefinition, or how MISO will adapt its market design for more complex operations. ■

MISO Board Week was held Sept. 12-14 at Renaissance Minneapolis Hotel, The Depot | © *RTO Insider LLC*

MISO News

MISO Promises Analyses on Long-range Tx; Stakeholders Divided on IMM Involvement

Stakeholders Concerned About Costs, Planning Assumptions, Control

By Amanda Durish Cook

MINNEAPOLIS — Amid the Independent Market Monitor's denunciation of MISO's fleet assumptions for long-term transmission plans, MISO lead planners last week defended their approach to planning for 2040.

Stakeholders, meanwhile, continued to debate whether it's proper for IMM David Patton to deviate from markets to weigh in on MISO transmission planning.

MISO Vice President of System Planning Aubrey Johnson said MISO is seeking an "optimal, cost-effective expansion" in its second, multibillion-dollar long-range transmission plan (LRTP) portfolio that can hold up under several hypothetical circumstances.

That comes two weeks after Patton repeated criticisms of MISO's future fleet assumptions behind its second LRTP portfolio. The IMM has alleged MISO is overestimating renewable additions and baseload generation retirements while underestimating future battery storage. He has said a transmission overbuild stands to harm market functions. (See *Market Monitor Questions MISO Fleet Assumptions in Long-term Tx Planning*.)

"We are not the resource planners," Johnson told board members at a Sept. 12 System Planning Committee of the MISO Board of Directors meeting. "But what we do is take these plans and goals from our members and make a path that shows how they can be accomplished."

Johnson said MISO "has not seen any indication" that members' plans have changed. It remains that 70% of MISO load is associated with members' decarbonization commitments, he said.

MISO hasn't yet recommended any transmission projects under the second LRTP portfolio. That's set to happen next year.

"This whole process has tension in it," Johnson said, referring to "standing-room-only" stakeholder workshops full of members with differing views on generation and transmission expansion. He promised that MISO will run several analyses and stress tests against multiple planning scenarios and the IMM's idea of the resource mix before recommending lines.

"We recognize that the portfolio we recommend, the state commissioners today might not be the commissioners that approve those projects," Johnson said.

Some stakeholders said the IMM's opinions on MISO's future fleet deserves research.

Alliant Energy's Mitch Myhre asked MISO to take the time to perform a sensitivity analysis that includes the IMM's view of the future and "arrive at a set of projects that have good business cases."

North Dakota Commissioner Julie Fedorchak said the expected second LRTP portfolio price tag at $20 billion to $30 billion warrants careful examination. She also said North Dakota supports MISO taking a deeper look at its battery storage projections.

"We are talking about extreme amounts of money, and that's not even taking into account the generation, that will be borne entirely by ratepayers," she said.

WEC Energy Group's Chris Plante said while the first, $10 billion LRTP portfolio was "low-hanging fruit" of known choke points on the system, the second LRTP portfolio is a more drastic investment.

But some MISO members took to the Sept. 12 Markets Committee of the Board of Directors to condemn Patton's disapproval of MISO's planning assumptions.

ITC's Brian Drumm said the IMM has "repeatedly invoked the authority of his office in an attempt to force MISO and its stakeholders to implement one person's vision for MISO's energy future."

"The IMM's attempt to influence LRTP tranche two regional transmission planning is neither necessary, impartial, effective, market monitoring [nor] within the scope of the plan," Drumm said.

Drumm said Patton's "out-of-scope intervention" in LRTP planning is "disruptive." He asked that MISO's board intervene and prevent the IMM from attempting to undermine MISO's fleet assumptions that "economically incorporate the letter and the spirit of the decarbonization and renewable energy goals of MISO's members and states."

Other stakeholders characterized the IMM's recent involvement in the fleet assumptions underpinning the LRTP as an 11th-hour attempt at circumventing MISO's second portfolio of long-term transmission planning.

Clean Grid Alliance's Beth Soholt said she believed MISO and members are adequately capturing the most likely range of future fleet mix possibilities.

"We need a grid that can support all this uncertainty and all of these changes," she said.

Soholt added that Patton's inappropriate foray into transmission planning comes as MISO is reupping the IMM's annual contract. She advised MISO not to expand monitoring duties to include planning.

Patton did not respond to *RTO Insider's* request for comment on the divide. He did not respond in real time during the Markets Committee. ■

| © RTO Insider LLC

NYISO News

NYPSC Continues Legal Battle Over NYISO's 17-Year Amortization

By John Norris

The New York Public Service Commission last week petitioned a federal court again to reconsider FERC's approval of NYISO's proposed change to the timeline for demand curves in its installed capacity market auctions (*ER21-502*).

This is the third time the PSC has asked the D.C. Circuit Court of Appeals to rule on NYISO's proposal to implement a 17-year amortization period when calculating the net annual cost of a hypothetical peaking power plant in its capacity markets and comes after FERC declined the PSC's request for a rehearing on Sept. 11. (See *NYPSC Seeks FERC Rehearing on NYISO's 17-Year Amortization*.)

NYISO is mandated to update the assumed operational lifetime of a hypothetical fossil fuel plant in its capacity market auctions every four years, but, in response to aggressive state climate and energy legislation, the ISO proposed reducing that assumed lifetime from 20 to 17 years.

The ISO argued the 2019 Climate Leadership and Community Protection Act imposes such strict net-zero standards for fossil fuel plants that their operational use would be dramatically reduced; however, the PSC contended the adjustment to a shorter period hurts New York ratepayers and is speculative.

The PSC reiterated previous arguments when requesting the court review FERC's decisions and its *denial* for a rehearing, including that a 17-year period could cost consumers $400 million, claiming FERC should have waited to rule until addressing other pending rehearing requests related to NYISO's compliance and asserting that FERC's decision departs from precedent.

D.C. Circuit Court of Appeals | *D.C. Circuit Court of Appeals*

The petition also cites a dissent submitted by FERC Commissioner Mark Christie, who expressed concerns about the May approval of the 17-year timeframe, which reversed previous rejections by the commission. Christie opted to not elaborate, citing pending rehearing requests related to that approval order.

Despite the legal wrangling, NYISO already has implemented the 17-year amortization period as part of its demand curve reset. ■.

NYISO News

NYISO Business Issues Committee Briefs

Seasonal Demand Curves

RENSSELAER, N.Y. — NYISO on Thursday secured Business Issues Committee approval of the ISO's proposal to create separate capacity demand curves for summer and winter beginning with the 2025/2026 capability year.

The ISO *proposed* the tariff *revisions* to better reflect winter and summer reliability risks and send clearer signals to the market about the value certain resources have in each season. It also said the changes are necessary to accommodate moving from annual capacity accreditation factors to seasonal ones in the future.

The changes are part of the latest demand curve reset, conducted every four years to update the parameters for NYISO's capacity market. The revisions now go to the Management Committee for approval Sept. 27.

NYISO/PJM Joint Operating Agreement

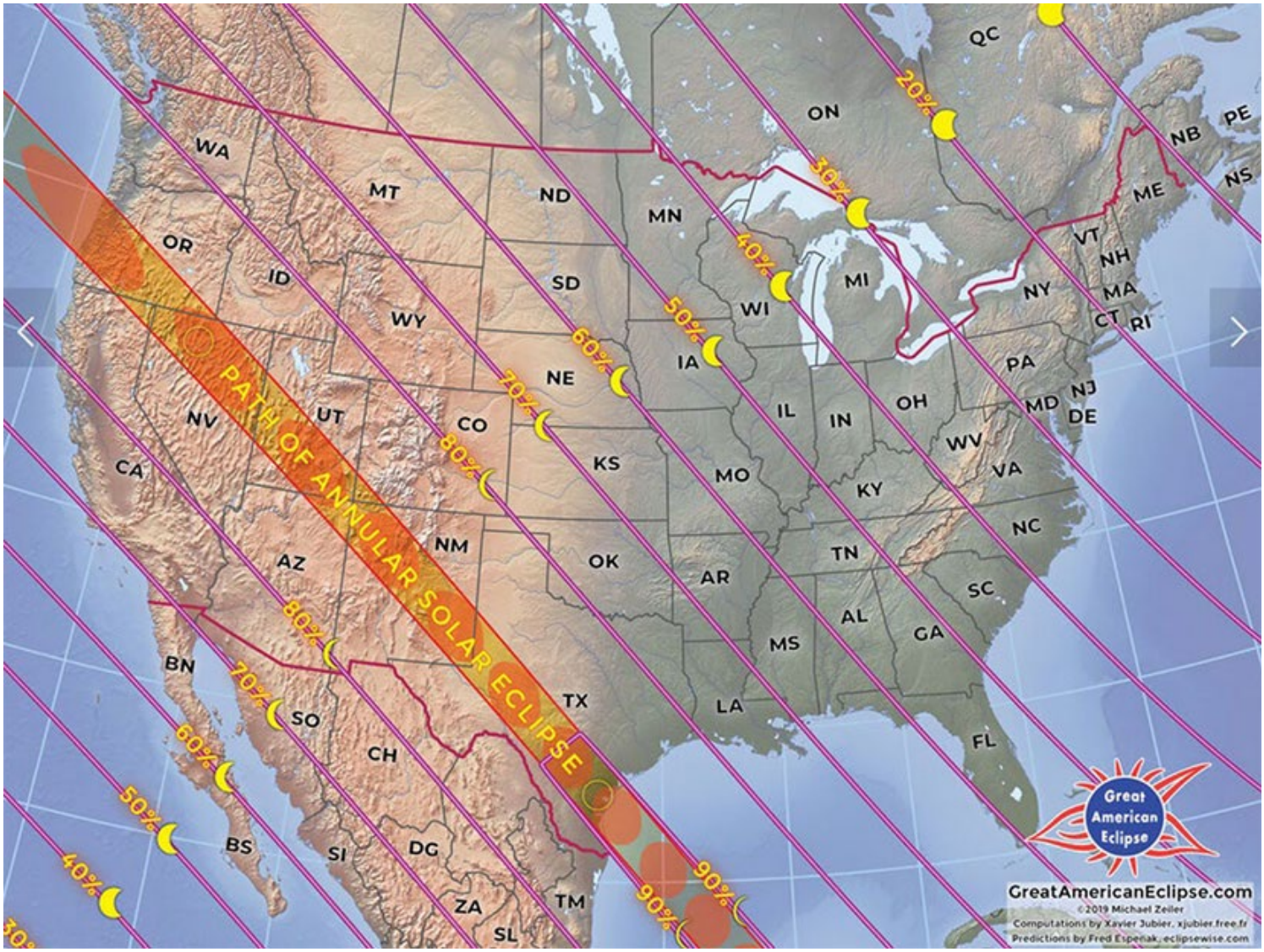
The BIC also recommended approval of *proposed revisions* to the Joint Operating Agreement between NYISO and PJM.

The revisions are intended to improve the coordination and data accuracy between the grid operators, particularly in the areas of resource adequacy and transmission planning.

A provision NYISO considers key would remove a *list* of interconnection tie facilities between the ISO and PJM out of the JOA and publish it on each of their websites, which the ISO argues would make it easier to adjust and increase transparency.

Stu Kaplan, partner at Troutman Pepper, asked if the changes made to the list could in any way change who has operational control over a New York facility.

NYISO did not have an immediate answer but responded that its proposals apply mostly to low-level equipment like substations, though it added that it will consider the issue moving forward.



Pathway for annular solar eclipse on Oct. 14, 2023 | *NYISO*

NYISO News

The MC will consider revisions at its meeting this month. NYISO anticipates implementation by the first quarter of 2024 if the Board of Directors and FERC approve them.

August Market Operations

NYISO Senior Vice President Rana Mukerji *presented* the August market operations report, noting that average energy prices were lower than both the previous month and August of last year. (See "July Market Performance," *NYISO Business Issues Committee Briefs: Aug. 16, 2023*.)

The month's average energy cost was 56% lower than last year, declining from $93.42/MWh to $40.13/MWh. Mukerji said lower temperatures led to lower loads.

Eclipse Preparation

At a separate meeting of the Installed Capacity and Market Issues working groups the same day, NYISO *updated* stakeholders about its preparations for two upcoming solar eclipses, including how it is coordinating with solar forecasters and its neighbors to mitigate the impact on New York's energy production.

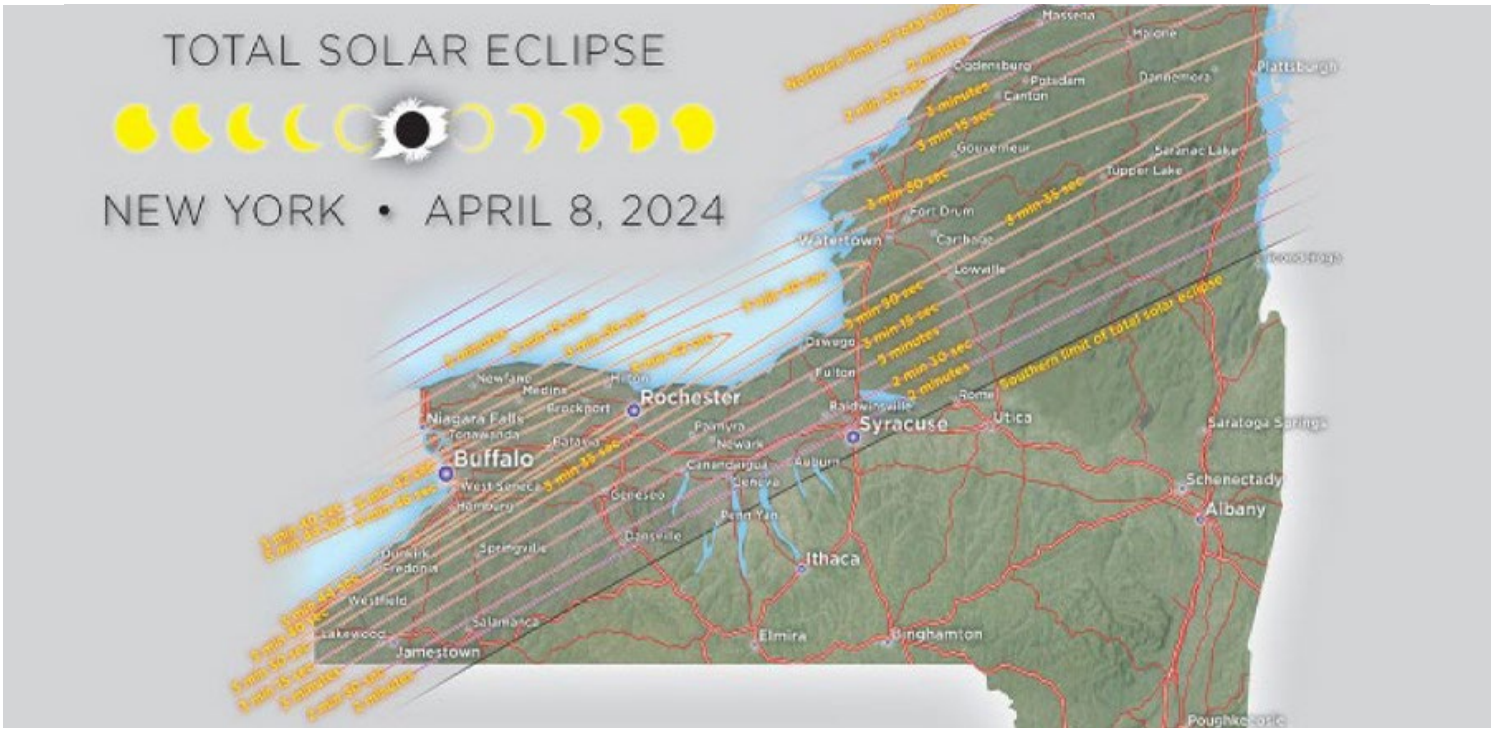
The ISO said October's annular solar eclipse — which will most impact Texas and the Western U.S. — could reduce solar output in parts of the state by 15 to 30%, with statewide behind-the-meter solar generation declining by as much as 700 MW and front-of-the-meter down 30 MW.

Next April's total solar eclipse will cause even greater disruption, as it will pass directly through New York. During the roughly 2.5-hour eclipse, NYISO forecasts that solar production could decline by more than 3,000 MW at the peak, as some areas of the state will be completely obscured for nearly four minutes.

The ISO also said that wind generation could be impacted by the eclipses, both because of cloud cover and the expected localized cooling that will lower wind speeds when the sun is obscured.

NYISO has said it expects to have enough resources available to cover potential shortfalls. (See "NYISO Updates & Eclipse Prep," *NY State Reliability Council Executive Committee Briefs: Sept. 8, 2023*.) ■

— John Norris



Path for total solar eclipse April 8, 2024 | *NYISO*

Northeast news from our other channels

Northeast Governors Ask Feds to Assist OSW Industry — NetZero Insider

NY Utility Thermal Energy Network Pilot Program Simmers — NetZero Insider

BNOW Calls for Standardizing, Sharing OSW Data — NetZero Insider

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

NYISO News

NYISO Operating Committee Briefs

Stability And Voltage Studies

The NYISO Operating Committee on Friday approved three studies aimed at helping the ISO alleviate congestion on its grid.

The ISO's Central East and Total East interfaces study reports, and its Central East voltage limit study, each sought to identify areas of the grid in need of upgrades to ensure it operates reliably under several different demand and environmental conditions.

The first two reports updated the definitions of the transmission components that make up the Central East and Total East interfaces and examined the impact of adding new 345-kV lines to the interface.

The Central East voltage limit study evaluated the grid's performance after the addition of several new lines and found that performance improved, allowing for an increase in the minimum level of energy loss that triggers contingency operations.

NYISO expects the new interface criteria to be integrated into grid operations following the deployment of updated models and software in October.

Shortage Pricing

The OC also approved *manual revisions* NYISO *says* would improve the accuracy of transmission shortage pricing by better reflecting the actual costs of relieving constraints.

The changes involve eliminating transmission constraint "relaxation" logic for facilities and interfaces that use a demand curve mechanism and introducing a six-step mechanism for those assigned a non-zero constraint reliability margin.

NYISO argued the revisions would reduce market inefficiencies by more accurately pricing the relief services that certain transmission projects provide to the grid.

The Business Issues Committee had approved the revisions the previous day. They are expected to become effective in October after the deployment of software updates.

August Operations Report

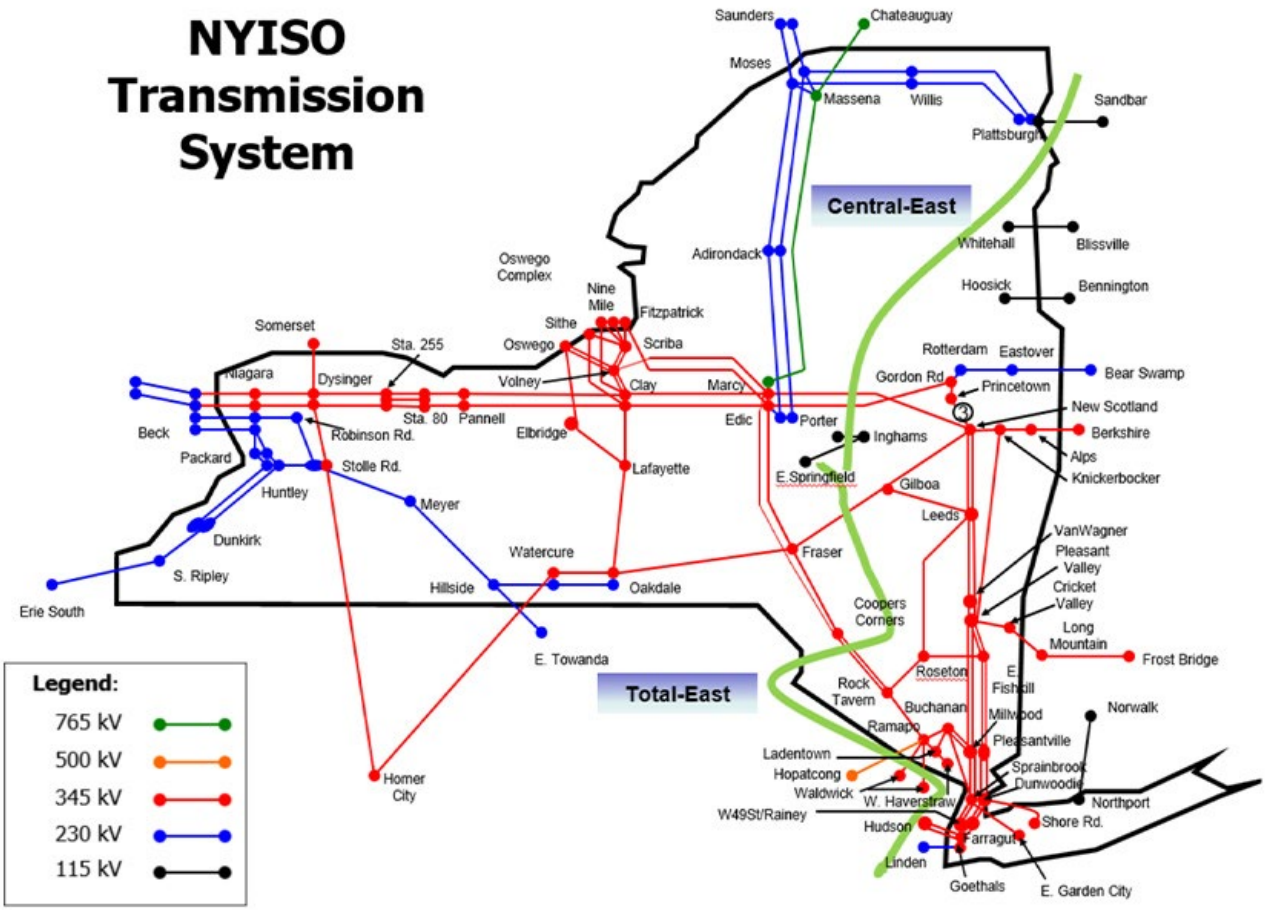
Aaron Markham, NYISO vice president of operations, informed the OC that August saw a peak load of 24,917 MW but that the summer's peak load of 30,200 MW occurred because of a heat wave Sept. 17.

Markham noted that the heat wave resulted in appropriately 1,500 MW of unforced outages.

He said NYISO is investigating the cause of the outages but that it had sufficient resources.

Markham also said the ISO has added 3 MW of energy storage and 66 MW of behind-the-meter solar resources since last month. ■

— John Norris



| *NYISO*

PJM News

PJM MRC/MC Preview

By Devin Leith-Yessian

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

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse proposed *revisions* to Manual 01: Control Center and Data Exchange Requirements that would specify that entities may have multi-layered communication methods and are required to notify PJM of a failure only if all modes have failed and only alternates remain. The revisions arose from the manual's periodic review. (See "Stakeholders Endorse Manual Revisions Related to Communication Failures," *PJM OC Briefs: Sept. 7, 2023*.)

C. Endorse proposed *revisions* to Manual 12: Balancing Operations that aim to clarify that reserve resources should respond to a synchronized reserve deployment when they receive notification through any of the existing Energy Management System datalinks. (See "Stakeholders Endorse Quick Fix on Synchronized Reserve Dispatch," *PJM OC Briefs: Sept. 7, 2023*.)

D. Endorse proposed *revisions* to Manual 28: Operating Agreement Accounting adding clarifying language, grammatical updates and removing terminated business rules.

Endorsements (9:10-10:30)

1. Enhancements to Deactivation Rules Issue Charge (9:10-9:45)

PJM's Chris Pilong will *review* a *problem statement* and proposed *issue charge* that address possible enhancements that can be made to deactivation rules. The problem statement lays out concerns PJM has identified with how compensation is determined under reliability-must-run contracts and the timeline for when generation owners must notify PJM of their intent to retire a unit. (See "Stakeholders Defer Vote on Generation Deactivation Issue Charge," *PJM MRC Briefs: Aug. 24, 2023*.)

The committee will be asked to endorse the proposed issue charge.

2. Reserve Certainty Issue Charge (9:45-10:30)

A. PJM's Donnie Bielak will review a *problem statement* and proposed *issue charge* that would create a new senior task force to explore reworking several areas of the reserve markets, including performance and penalties, aligning offers with resource capability and fuel procurement and reserve procurement targets. (See "PJM Provides First Read on Reserve Certainty Issue Charge," *PJM MRC Briefs: Aug. 24, 2023*.)

B. Independent Market Monitor Joseph Bowring and Deputy Monitor Catherine Tyler will review an *alternative version* of the issue charge, in which the Monitor has removed several key work areas and added specificity to others.

The committee will be asked to endorse one of the proposed issue charges.

Members Committee

Consent Agenda (1:20-1:25)

C. Endorse a *proposal*, with corresponding tariff *revisions*, addressing the amount of credit market participants must maintain to satisfy their peak market activity requirement. (See "Peak Market Activity Credit Changes Endorsed," *PJM MRC Briefs: Aug. 24, 2023*.)

Issue Tracking: *Peak Market Activity Credit Requirement*

Endorsements (1:25-1:35)

1. Nominating Committee Elections (1:25-1:35)

PJM's Dave Anders will *review* the sector nominees under consideration for election to the 2023-24 Nominating Committee. The committee will be asked to elect the sector representatives upon first read. ■

SPP News

WAPA, Basin Electric Commit to SPP's RTO West

By Tom Kleckner

SPP said last week that recent announcements by the Western Area Power Administration (WAPA) and Basin Electric Power Cooperative have rounded out the group of western utilities that plan to pursue membership in the grid operator's Western Interconnection RTO market.

The announcements give SPP seven utilities interested in becoming the SPP RTO West's inaugural full members when it begins operations in 2026. SPP will become the first U.S. grid operator to provide RTO services in both the Eastern and Western Interconnections.

CEO Barbara Sugg said on X, the social network formerly known as Twitter, "I am excited for these commitments to continue growing the RTO in the West and look forward to working together to keep the lights on!"

WAPA Administrator Tracey LeBeau issued a *decision letter* Sept. 8 *authorizing three of its four regions* — Colorado River Storage Project (CRSP), Upper Great Plains (UGP) and Rocky Mountain — to pursue final negotiations with SPP for RTO West membership. A federal agency, WAPA had to first file a *recommendation report* in the *Federal Register* and solicit public input.

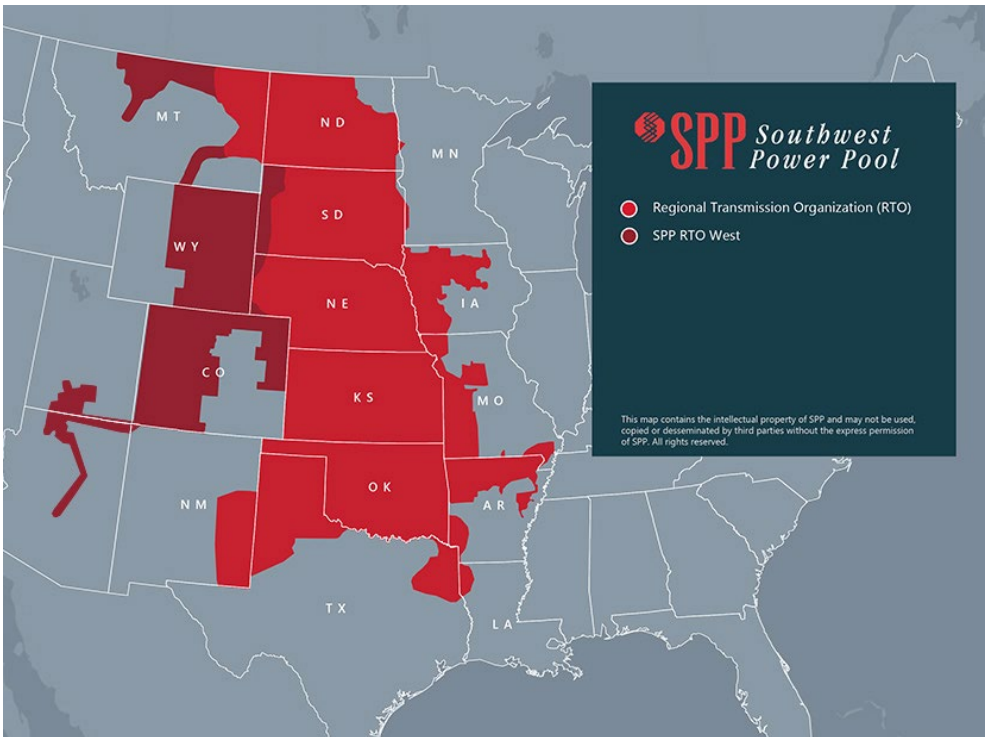
LeBeau said participating in SPP RTO West is consistent with WAPA's commitment to develop alternative ways to retain and increase the value of its resources and services.

"Taking under careful consideration our customers' and our industry's collective movement to adapt to a rapidly changing energy environment, I am pleased at the progress we have made as WAPA takes a further thoughtful step in pursuing final negotiations with SPP," she said in a *statement*.

As part of the final negotiations, WAPA will develop implementation details to pseudo-tie CRSP customers from the Western Area Colorado Missouri balancing authority area to the Western Area Lower Colorado BAA. It said this will address CRSP customer concerns about the potential effects of RTO membership for entities outside the footprint.

If the final negotiations with SPP are successful, CRSP and Rocky Mountain will execute membership agreements and UGP will expand its participation in SPP's eastern RTO.

Basin Electric alerted SPP of its intent to pursue RTO membership on Sept. 12. It must execute a signed commitment agreement by Oct. 10.



SPP's current and proposed RTO footprints in the Western and Eastern Interconnections | *SPP*

WAPA and Basin Electric already are members in SPP's Eastern Interconnection footprint. Both were part of the Integrated System, which joined SPP in 2015. (See *Integrated System to Join SPP Market Oct. 1*.)

WAPA annually markets and transmits more than 28,000 GWh of renewable power from 57 hydroelectric power plants in 15 western and central states. *Basin Electric* is a generation and transmission association with 141 member cooperative systems across nine states serving 3 million consumers.

Other interested RTO West members include:

- Colorado Springs Utilities;
- Utah's Deseret Generation and Transmission Cooperative;
- Municipal Energy Agency of Nebraska;
- Platte River Power Authority in Colorado; and
- Tri-State Generation and Transmission Association.

SPP has been working with the utilities for almost three years to evaluate the benefits and requirements of RTO membership. A *Brattle Group study* has identified at least $49 million in annual savings for members of SPP RTO West.

The western RTO's success hinges on SPP's use of three DC ties between its two footprints to optimize energy markets and create new opportunities for energy transfers and improved system resilience for both current and future members.

"Creating multiple market options for new members will enable market designs that align with the unique needs of one or more geographic regions and provide opportunity for all to benefit," Bruce Rew, SPP's senior vice president of operations, said.

The potential members currently are participating in the grid operator's Western Energy Imbalance Service (WEIS) market. SPP says the WEIS provided an estimated $31.7 million in net benefits for its participants last year and reduced wholesale energy costs by $1.35/MWh through real-time dispatch.

SPP expects RTO West to add additional members, beginning in 2027. They have a March 1 deadline to indicate their interest in membership.

The RTO has 110 member companies in the Eastern Interconnection. ■

SPP News

SPP REAL Team Compromises on PBA, ELCC Revisions

MMU, SPP Work Together on Outage Data, Weighting, Storms

By Tom Kleckner

DFW AIRPORT, Texas — SPP stakeholders this month asked two working groups to consider compromise language on a pair of tariff revisions related to resource adequacy policies.

The Resource and Energy Adequacy Leadership (REAL) Team voted to ask the Supply Adequacy and Cost Allocation working groups (SAWG and CAWG) to review the revision requests (*RR554* and *RR568*) following the team's Sept. 8 meeting. RR554 details the performance-based accreditation (PBA) policy, and RR568 lays out the effective load-carrying capability (ELCC) policy.

SPP staff proposed the compromise after pushback from the Market Monitoring Unit (MMU) and a lengthy discussion among the REAL Team's members. The Monitor said it couldn't support RR554 as written over accuracy and equity concerns, and it said RR568 included inconsistencies that could be considered unduly discriminatory.

"I think it's important that we attempt to restore trust among the MMU that we will deliver on commitments," Texas Public Utility Commissioner Will McAdams, the REAL Team's chair, said during the meeting. "I think this policy debate has highlighted that it's just trying to identify and assign the appropriate vehicle to carry out these strategic aims of the organization."

Texas regulator and REAL Team Chair Will McAdams listens to speakers during SPP's Resource Adequacy Summit. | © *RTO Insider LLC*

The SPP MMU's John Luallen (left) lays out the Monitor's objections to proposed accreditation policies as MMU Vice President Keith Collins listens. | © *RTO Insider LLC*

Keith Collins, the MMU's vice president, said he appreciated McAdams' effort to advance the RRs.

"We're supportive of considering [the potential RR changes] and moving them forward," he said.

Staff said the compromise's modifications could be implemented while still maintaining the RRs' structural frameworks and timeline. The primary change is using seven years of historical outage data, rather than 10, in determining conventional resources' accredited capacity under RR554.

The MMU had suggested five years of historical data, saying the PBA "asymmetrically" treats historical performance. It said outage exemptions are inconsistent with ELCC and performance is assessed over the entire season, not when needed.

The compromise also proposes adding out-of-management-control events, such as tornadoes and other violent storms, in calculating the ELCC for wind, solar and storage resources, and weighting the PBA during resource advisories, conservative operations and energy emergency alerts.

Under RR554, PBA places more value on conventional resources that are reliable and available to perform when needed the most. It is intended to ensure the appropriate capacity value to calculate SPP's planning reserve margin.

RR568 is a response to FERC's rejection this year of SPP's first attempt to add ELCC (the amount of incremental load a resource can dependably and reliably serve during peak hours). The revision reduces a three-tiered structure to just two, firm and nonfirm transmission service. Staff will study only firm service in its ELCC analysis. (See *FERC Grants Rehearing of SPP Capacity Accreditation Proposal*.)

The REAL Team has targeted the October series of governance meetings to gain approval of the two RRs. They are scheduled to be deployed for the 2026 summer season.

The SAWG meets Sept. 26-27 and the CAWG meets Oct. 3. The REAL Team will review their input during an Oct. 5 virtual meeting.

"Time is of the essence, and we need to have strategies in place that include contingencies," Director Steve Wright said. ■.

Company Briefs

Chinese Solar Supplier Trina Plans $200M Factory in Texas

Trina Solar last week announced it is planning a $200 million manufacturing facility in Texas, weeks after the U.S. said the Chinese panel supplier was bypassing tariffs.

The site will be able to make about 5 GW of panels a year using polysilicon sourced in the U.S. and Europe.

Production is expected to begin in 2024.

More: *BNN Bloomberg*

BP CEO Looney Resigns over Past Relationships with Colleagues

BP CEO Bernard Looney resigned abruptly on Sept. 12 over past relationships with colleagues, the company said, less than four years after taking over.

The company said Looney was "not fully transparent" about past personal relationships with colleagues. BP's board reviewed allegations of what it said were Looney's personal relationships with colleagues in May 2022, based on anonymous information. It said Looney disclosed a small number of such past relationships that occurred before he became CEO, but found no breach of company code.

Chief Financial Officer Murray Auchincloss will serve as CEO on an interim basis.

More: *The Wall Street Journal*

Samsung C&T Sells 3-GW Solar Energy Project in US to Sunraycer

Samsung C&T Renewables, the renewable energy corporation of South Korea's Samsung C&T in the US, announced last week that it has signed a contract with Sunraycer Renewables for a 3-GW solar and energy storage system project in Texas.

The deal involves the sale and development of 15 projects at varying stages of development across Texas to Sunraycer. Currently, six of the projects are solar with a combined capacity of 1 GW, while nine are storage systems totaling 2 GW.

Financials of the deal were not disclosed.

More: *The Korea Economic Daily*

Federal Briefs

EPA Restores Power of States, Tribes to Review Projects to Protect Waterways

EPA last week reversed a Trump-era action that limited the ability of states and tribes to review pipelines, dams and other federally regulated projects within their borders.

The agency said the new regulation, which will take effect in November, will empower local authorities to protect rivers and streams.

The rule will be significantly slimmed down from an earlier proposal Because of a Supreme Court ruling that weakened regulations protecting millions of acres of wetlands. That ruling, in a case known as *Sackett v. EPA*, sharply limited the federal government's jurisdiction over wetlands, requiring that wetlands be more clearly connected to other waters such as oceans and rivers.

More: *The Associated Press*

Agriculture Deptartment to Distribute $1B for Tree Planting

U.S. Department of Agriculture Secretary Tom Vilsack last week announced $1.13 billion in funding for 385 projects around the nation that will help communities plant and maintain trees intended to reduce extreme heat, benefit health and improve access to nature.

The efforts will focus on marginalized areas in all 50 states, as well as D.C., Puerto Rico, the Virgin Islands and some tribal nations.

Separately, the USDA's Forest Service allocated $250 million to most state and territory forest agencies to benefit urban tree canopies and access to nature.

More: *The Associated Press*

Biden Nominates Memphis City Council Member for TVA Board

President Joe Biden last week nominated Memphis City Councilwoman Patrice Robinson to the Tennessee Valley Authority Board of Directors.

Robinson, who has served on the council since 2016 and terms out this year, was previously on the Memphis-Shelby County School Board for 13 years. On the council, she chaired the Memphis Light, Gas and Water committee.

The nomination requires confirmation by the Senate.

More: *Memphis Commercial Appeal*

BLM Approves Geothermal Test Bed Project

The Bureau of Land Management approved the Rodatherm Geothermal Test Bed project.

The Rodatherm Energy Corporation geothermal system is a fully isolated Organic Rankine cycle system, converting underground heat sources into mechanical energy that will be used to generate electrical power. It will try to determine if an advanced geothermal generation facility is commercially viable on BLM-managed lands in Beaver and Millard counties in Utah.

The project is reportedly planned to operate for one year.

More: *KTVX*

Mid-Atlantic news from our other channels

NJ Businesses Demand Halt to EV Sales Promotion Rules

NetZero Insider

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

State Briefs

FLORIDA

Palm Coast to Test EV Charging Fee at City Hall

The Palm Coast City Council last week unanimously agreed to try charging a fee to use the city hall's electric vehicle charging stations.

The council agreed on a fee structure of 18 cents per kilowatt-hour, with an initial fee of 50 cents when someone first plugs in the car. The 50-cent connection fee would go to ChargePoint, the company the city uses, and would cover the use of ChargePoint's cloud services, plus the city's warranty on the charging stations.

The council has not set a date to implement the fee.

More: *Palm Coast Observer*

IOWA

Utilities Board Approves Tx Line

An underground transmission line from Mason City to Illinois was approved by the state Utilities Board last week.

The project by SOO Green HVDC Link ProjectCo will place approximately 174 miles of 525-kV underground HVDC transmission line in Allamakee, Cerro Gordo, Chickasaw, Clayton, Dubuque, Floyd, Jackson and Winneshiek counties in Iowa, and continue into Illinois.

The board said it found the proposed line necessary to serve a public use and represents a reasonable relationship to an overall plan of transmitting electricity in the public interest. The order also says vesting SOO Green with the right of eminent domain is necessary for public use as discussed in the order.

More: *KIMT*

KANSAS

Sedgwick County Passes Six-month Ban on Commercial-scale Solar Projects

The Sedgwick County Commission last week passed a six-month moratorium on new commercial-scale solar projects within unincorporated areas of the county.

The moratorium is meant to allow the county's planning department to study potential regulations for solar farms. It doesn't apply to projects inside city limits or solar panels added to homes or businesses.

More: *KMUW*

MICHIGAN

Dems Push Carbon-neutral Goal Back to 2040

Democratic lawmakers pushing bills that aim to get state utilities off fossil fuels said they are extending the proposed deadline by five years, from 2035 to 2040.

During a Senate Energy and Environment Committee hearing, lawmakers were originally scheduled to take testimony on three bills tied to the energy overhaul, including a bill calling for utilities to achieve 100% carbon-free energy by 2035. Instead, they deferred testimony on two bills pending new language sponsors said is forthcoming. Among the changes to the carbon-free energy bill is a new deadline of 2040.

The forthcoming version will also require utilities to acquire 2,500 MW of storage by 2030.

More: *Bridge Michigan*

MINNESOTA

PUC Rejects Xcel's Request to Reconsider Rate Case Decision

The Public Utilities Commission last week voted 5-0 against reconsidering a June decision on Xcel Energy's rate case without allowing comments from the company or other parties.

Xcel asked the PUC to rehear the case, claiming the commissioners erred legally and demonstrated "unreasonableness" when they decided to increase the company's rates by $306 million. Xcel had been asking for an increase of $440 million. The PUC briefly discussed new evidence submitted by Xcel and then voted to exclude the new documents from the record.

The next step for Xcel, if it chooses to continue to fight the decision, is to take its case to the Court of Appeals.

More: *Star Tribune*

NORTH DAKOTA

PSC to Reconsider Summit Carbon Solutions Pipeline Denial

The Public Service Commission last week granted a request from Summit Carbon Solutions to reconsider its route permit application after denying its original application in August.

Summit has proposed a new route farther north of Bismarck.

North Dakota was the first state to bring a Summit pipeline route to a vote, denying that application on Aug. 4. South Dakota also denied an application a week later.

More: *Inforum*

TENNESSEE

Shelby County Approves Solar Farm Moratorium

Shelby County commissioners last week approved a moratorium on commercial solar farm developments.

The moratorium freezes any permits for commercial farms in the commercial conservation agriculture district. Commissioners can grant an exception for anyone seeking to move forward with construction, following the process of special use permits.

More: *Memphis Commercial Appeal*

VIRGINIA

Dominion Seeks Air Permit for Proposed Chesterfield Gas Plant

Dominion Energy's plans to build a new natural gas plant in Chesterfield will require a state permit for major new sources of emissions, the Department of Environmental Quality said last week.

Mike Dowd, the DEQ's director of air and renewable energy, told the State Air Pollution Control Board the plant will require a prevention of significant deterioration permit.

Dominion revived plans this summer for a natural gas plant adjacent to its fossil fuel facility in Chesterfield County, saying it is needed to meet a projected increase in electricity demand from data centers and EVs. The plans call for four simple cycle com-

bustion turbines capable of generating 250 MW each. Natural gas would be the primary fuel source, with oil and possibly hydrogen as backups.

More: *Virginia Mercury*

SCC Down to 1 Commissioner

The State Corporation Commission could soon be unable to rule on cases for the first time in state history because it has only one judge sitting on the bench.

The General Assembly last week failed to fill two vacant seats on the three-member panel, and now former Commissioner Patricia West, who has been acting as a substitute judge, will have to relinquish that role after her appointment to the Parole Board by Gov. Glenn Youngkin almost three weeks ago. When that occurs, Judge Jehmal Hudson will be the only member left.

A stalemate between the Republican-controlled House and Democratic-controlled Senate has left one seat on the SCC vacant for 18 months, after the House blocked the reelection of Judge Angela Navarro in retaliation for the Democrats' ouster of West the previous year.

More: *Richmond Times-Dispatch*

WEST VIRGINIA

PSC Approves $88.8M Rate Hike for Appalachian Power, Wheeling Power

The Public Service Commission last week approved an $88.8 million fuel cost rate increase for Appalachian Power and Wheeling Power.

The hike was approved to cover the companies' projected fuel costs for Sept. 1, 2023, through Aug. 31, 2024.

The PSC's order did not list average monthly rate increases for classes of ratepayers. The agency ordered the companies to file tariff sheets reflecting the rate hike within 15 days.

More: *Charleston Gazette-Mail*