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RTO Insider

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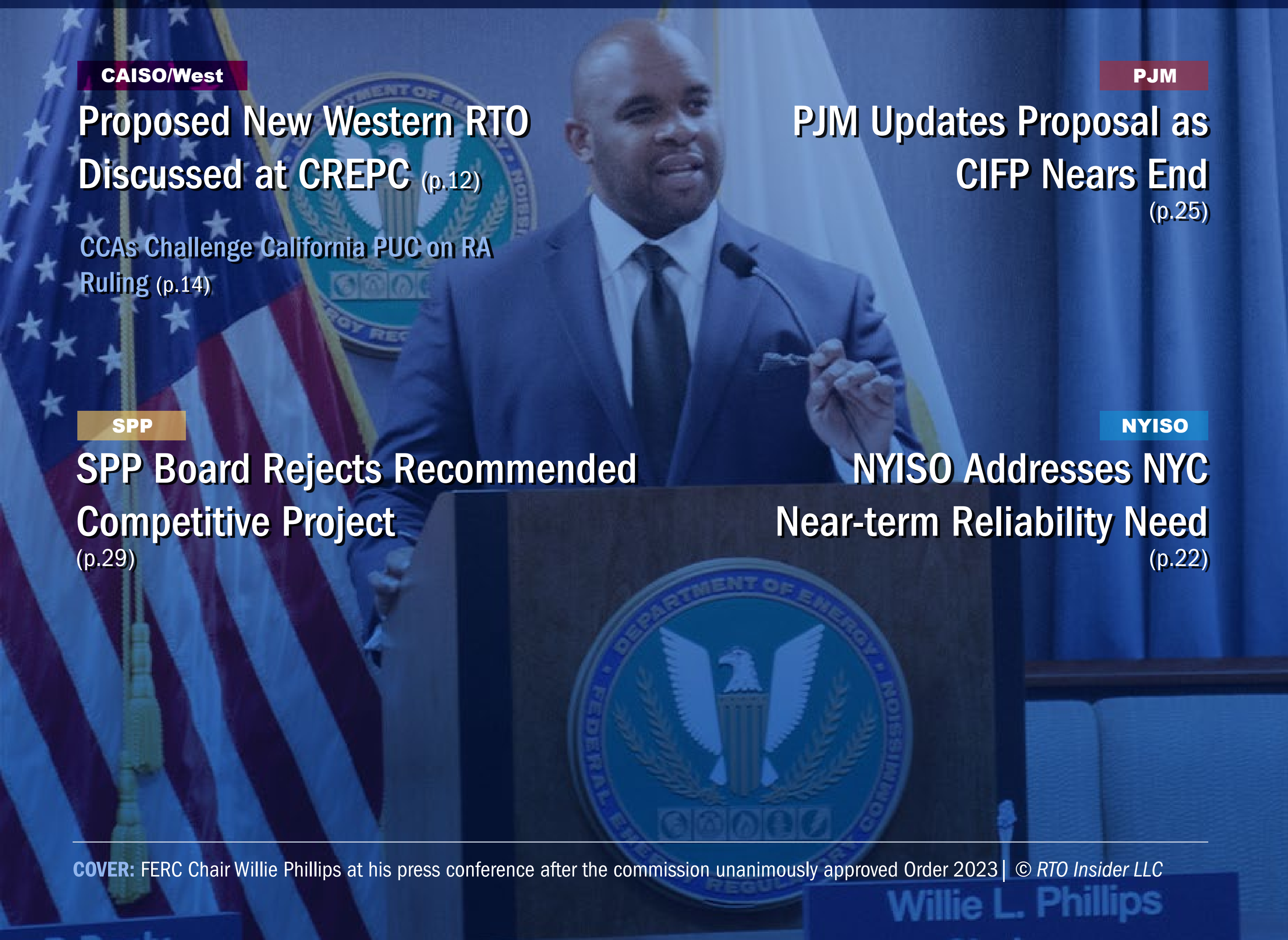

COVER: FERC Chair Willie Phillips at his press conference after the commission unanimously approved Order 2023 |

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In this week's issue

FERC/Federal News

FERC Updates Interconnection Queue Process with Order 2023

By James Downing

WASHINGTON — FERC on Thursday unanimously issued Order 2023 revising its *pro forma* generator interconnection queue rules to speed up the backlogged process (*RM22-14*).

The rule will ensure that generation resources are able to connect to the grid in a reliable, efficient, timely and transparent manner, acting Chair Willie Phillips said at a press conference after the commission's monthly open meeting.

"The final rule is one of the largest in FERC's history. It represents the largest and most significant set of interconnection reforms since the ***pro forma*** interconnection procedures were created two decades ago," Phillips said. "Our country has a severe interconnection backlog. Currently there are 2,000 GW of resources in interconnection queues, the largest backlog in history." (See *LBNL: Interconnection Queues Grew 40% in 2022*.)

The rule would shift the *pro forma* interconnection rules from a first-come, first-served serial process to a first-ready, first-served cluster study process. It ramps up financial requirements for developers and sets penalties for transmission providers that fail to meet deadlines for completing interconnection studies. (See *FERC Proposes Interconnection Process Overhaul*.)

The rule also requires interconnection studies to consider grid-enhancing technologies (GETs) and sets new reliability standards for inverter-based resources.

Order 2023 comes out of the Advanced Notice of Proposed Rulemaking issued in 2021 under Chair Richard Glick, which has also produced a still-pending NOPR on transmission planning and cost allocation. (See *FERC Issues 1st Proposal out of Transmission Proceeding*.)

"We will not stop work on the long-term and regional planning transmission NOPR," Phillips said. "We look forward to, in the months ahead, finalizing that proposal as well. And together ... we will have the greatest transmission reforms in a generation to come out of FERC."

All of the other commissioners praised the process around developing the final rule, with Commissioner James Danly saying that while he would have preferred looking into the six

FERC Chair Willie Phillips at his press conference after the commission unanimously approved Order 2023 | © RTO Insider LLC

FERC Interconnection Rule Sets Penalties, Ends 'Reasonable Efforts' Standard

Commission Shows Frustration over Transmission Providers' Missed Deadlines

By Rich Heidorn Jr.

FERC's long-awaited revamp of its generator interconnection procedures will make it more costly for developers to enter and leave queues and impose penalties on transmission providers that fail to complete studies on time.

Order 2023 (*RM22-14*) sets a 150-calendar day deadline for completing stability analyses, power flow analyses and short circuit analyses required to study complex clusters involving numerous interconnection requests.

FERC said the 150-day deadline gives transmission providers "sufficient time to perform these technical cluster studies while providing certainty about the timeline for the interconnection process."

The commission cited reports filed by transmission providers that showed of the 2,179 interconnection studies completed in 2022, 68% were issued late and another 2,544 studies were still ongoing and past their deadlines as of the end of the year. All RTOs/ISOs except CAISO and 14 non-RTO/ISO transmission providers reported delayed studies for the year.

About 80% of transmission providers reported delayed studies in at least one of the past three years (2020-2022) and 57% had delayed studies in at least two, FERC said. The National Association of Regulatory Utility Commissioners complained to FERC that "nearly all transmission providers across the country, including many transmission providers that have implemented queue reforms, regularly fail to meet interconnection study deadlines."

'Reasonable Efforts' Standard

Previously, the *pro forma* large gener-

FERC/Federal News

ISO/RTO interconnection queues individually, the final rule was a successful collaboration among the four sitting commissioners.

"Take me at my word when I say it because I don't give compliments," Danly told Phillips. "I pay you one here: You set up a set of circumstances where there was genuine collegiality amongst the offices in shaping the rule."

Reforming the queues is important, Commissioner Allison Clements said, as many grid operators have signaled that they will need additional resources soon to help keep the lights on.

"While we're not looking to replace retiring thermal units on a one-to-one basis with solar and wind, getting these resources online, as the grid operators have told us, is critical to help alleviating their own concerns," she added.

Clements also lauded Order 2023's embrace of GETs, many of which are mature technologies that have been around longer than some consumer items that have long since gone out of fashion, such as floppy disks and the Sony Walkman.

Commissioner Mark Christie said the rule was a step toward unclogging the queues around the country. Ideally it will not conflict with any revisions that grid operators have made on their own, such as PJM's, he added. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

"That's one of the issues that I address in my concurrence ... the question of whether we have appropriate hold-harmless language with regard to existing reform efforts," Christie said.

As with the old *pro forma* rules, ISO/RTOs will be able to seek an "independent entity" variation from FERC, and even vertically integrated utilities can get an exemption if they prove their rules are consistent with, or superior to, the new minimum standards. Some grid operators are engaged in changes that go well beyond what FERC has required with Order 2023. (See *CAISO Tries to Shake up Its Interconnection Process*.)

Given that the country has 2,000 GW of projects in the queue, which is double the amount of generation actually operating today, it is clear that the backlog needs to be worked through, Phillips said.

"Our government rules and regulations need to keep pace with the needs of our energy grid," he added. "And so, while I applaud the RTOs that have moved forward with reforms, I think they've done it because, quite frankly, they know that FERC was moving aggressively to finalize this rule. And that's a good thing. We want to make sure we recognize regional flexibility. What works in Alabama may not work in the Northwest, or what works in New York may not work in Arizona; we recognize that. But let me say this: No one region does every single thing that we put forward in this rule."

Stakeholders Applaud Rule, but Await Changes on Transmission

Most initial reactions to Order 2023 were in praise of FERC for addressing the issue of clogged queues, but they also called on it to continue with its work on transmission reforms.

"Advanced Energy United and our members applaud the commission for identifying the urgent need for interconnection reform and for working diligently to put forward a final order that will start to improve the broken interconnection process," said Managing Director Caitlin Marquis. "In light of the scope of the interconnection challenge, we also appreciate acting Chair Phillips' recognition that there is 'so much more to do' and hope to see this momentum maintained with follow-up efforts by the commission to address additional interconnection reform needs."

All were commenting based on what information FERC released at its meeting, with the order not being released as of press time Thursday evening. But AEU welcomed the commission's decision to move away from non-financial "readiness" requirements that were unworkable while keeping provisions to hold transmission providers accountable to deadlines, with penalties growing every day they are late.

"While ACEG welcomes approval of these reforms, the best way to address interconnection delays is still to improve the planning and development of new transmission lines," said ACEG Executive Director Christina Hayes. "As the commission begins its August recess, it is critically important that it continue to make progress on several outstanding items, including the planning and cost allocation rule. FERC has a crucial role to play in protecting the long-term reliability of our energy system, which is why it needs a full complement of members. We hope the president will expeditiously fill any vacancies so FERC can continue its important work."

The Sierra Club also welcomed the rule, saying it was hopeful it would help grid operators clear out the 2,000-GW backlog.

"Moving these renewable generation and storage facilities from the queue to the real world is a critical step toward creating a clean,

ator interconnection procedures held transmission providers to a "reasonable efforts" standard for completing studies, defined as "actions that are timely and consistent with good utility practice and are substantially equivalent to those a party would use to protect its own interests."

Transmission providers argued that many of the delays resulted from situations outside of their control, including large numbers of speculative interconnection requests, a shortage of qualified engineers, delayed data from interconnection customers and cascading restudies caused by withdrawals. MISO said most of its delays resulted from the need to wait for affected systems studies.

Some commenters warned that firm deadlines might lead transmission providers to prioritize speed over accuracy and the identification of the most efficient solutions. National Grid said it could result in later corrections to engineering requirements and cost estimates, causing more late-stage queue withdrawals.

The Edison Electric Institute and Eversource Energy complained that FERC's Notice of Proposed Rulemaking (NOPR) failed to make the case for why reliance on good utility practice remains sufficient in other situations, but not for interconnection studies. New York's Transmission Owners and Eversource said FERC should postpone penalties until it has allowed the other process changes to take effect.

But public interest and clean energy groups said the transmission providers were ignoring potential solutions, such as policy and process improvements and increasing spending on staff. Advanced Energy Economy said accepting high interconnection queue volumes as a legitimate cause for delays would provide providers "a permanent free pass" to miss deadlines.

Losing Patience

FERC demonstrated little patience for the providers' excuses.

"The reasonable efforts standard worsens current-day challenges, as it fails to ensure that transmission providers are keeping pace with the changing and complex dynamics of today's interconnection

FERC/Federal News

reliable and efficient energy grid, and we look forward to ensuring any process improvements here are implemented swiftly and fairly by grid operators across the country," Sierra Club Senior Attorney Greg Wannier said.

The rule's requirements for transmission providers to meet deadlines or face fines are a welcome new development because previously the onus was put on the developers of wind, solar and storage who were creating the demand for interconnection, Jason Burwen, a vice president at the storage firm GridStor, said in an interview.

The final rule changes how storage's impact on the grid is studied in the interconnection process. Current interconnection planning processes often assume the worst-case scenario with storage charging at the peak demand hours, but the NOPR proposed shifting that to a more real-world use of the technology, Burwen said.

The new rules will allow storage developers to submit a business case to grid operators that lays out how the facility will actually be used, thus avoiding overestimates of their grid impacts, according to the order. Standalone storage, hybrid facilities and co-located storage can all submit such business cases, which transmission operators can disagree with if they are not consistent with "good utility practice."

The order sets up a process in which the transmission owner explains its disagreement in writing and the storage project seeking interconnection can come back with a second attempt that address those concerns.

While storage is not as dependent on transmission expansion as wind and solar, it does need to see the grid expand to reach its maximum potential, Burwen said.

"Even these interconnection reforms ... are probably a few years out from really kicking in and changing the way in which business is done," Burwen said. "But it's much more matching the timescale of the pain that wind, solar and storage project developers are facing as they try to build stuff and do so on the timelines that any rational investor is going to expect of them."

RTOs React

RTOs had limited response to the order at press time; the text of the 1,481-page final rule wasn't posted until Friday evening.

MISO said it is assessing how the new rules will interact with its proposal to limit queue submissions to about 73 GW annually, triple its entry fees and establish more rigorous land obligations and escalating penalty charges. (See *MISO Aims for Manageable Interconnection Queue*.)

"The commission has acknowledged MISO's leadership in developing innovative solutions to the interconnection challenges. MISO appreciates the commission has codified many of them in Order 2023, and MISO is already assessing additional reforms to improve the quality and viability of future submissions," RTO spokesperson Brandon Morris said in a statement to *RTO Insider*. "MISO is reviewing how the current rule can support these efforts and not slow these future reforms to help address the interconnection challenges in the MISO region."

NYISO referenced its ongoing engagement with stakeholders to improve its interconnection processes. (See *NYISO Stakeholders Still Questioning Interconnection Queue Proposal*.)

"The NYISO began efforts to improve the interconnection process in 2022, recognizing the need and urgency for reform. Efforts to accommodate new technology proposing to interconnect to the grid and developing efficiencies in the process are well underway," said Kevin Lanahan, the ISO's vice president of external affairs and corporate communications. "As part of these efforts, the NYISO has held numerous open forums where stakeholders have provided valuable feedback and proposals."

PJM spokesman Jeff Shields said the RTO would postpone comments until it had reviewed the order but noted that it implemented its new interconnection queue process in July. (See *ACORE Report Highlights Billions of Dollars in PJM's Generator Queue*.)

"PJM expects to study the interconnection of more than 260,000 MW of mostly renewable resources. The process will speed up and streamline generation interconnection requests, improve project cost certainty, and significantly improve the process by which new and upgraded generation resources are introduced onto the electrical grid," Shields said.

CAISO referred to its NOPR comments, which supported eliminating the "reasonable efforts" standard and imposing penalties for missed deadlines. It also noted it was the only ISO/RTO that did not report missing any study deadlines in 2022.

ISO-NE and SPP declined to comment. ■

Amanda Durish-Cook, Tom Kleckner, Devin Leith-Yessian, Hudson Sangree, Jon Lamson and John Norris contributed to this story.

queues," the commission said. "Contrary to the assertions of some commenters, we believe that there are steps within transmission providers' control, from deploying transmission providers' resources to exploring administrative efficiencies and innovative study approaches, to better ensure timely processing of interconnection studies to remedy existing deficiencies."

It noted that the order seeks to reduce speculative interconnection requests with stricter requirements for entering and remaining in the queue (site control requirements, commercial readiness deposits and withdrawal penalties) and also seeks to improve efficiency by switching to the first-ready, first-served cluster study process from the serial, first-come, first served process.

The penalties, FERC said, "ensure that transmission providers are doing their part as well."

Penalties

The NOPR proposed a penalty of $500 per business day that the study is late, but the commission said it was persuaded that was too low, noting that a study delayed by six months (126 business days) would result in a penalty of only $63,000. "We view such a penalty as insufficient considering that the purpose of the penalty is to incentivize timely study completion that may be achieved, for example, by hiring additional personnel or investing in new software," FERC said.

Instead, it imposed per-day penalties of:

- $1,000 for delays of cluster studies;
- $2,000 for delays of cluster restudies;
- $2,000 for delays of affected system studies, and
- $2,500 for delays of facilities studies.

Penalties will be distributed to interconnection customers on a pro rata per interconnection request basis to offset their study costs.

As a concession to the transmission providers, FERC said it will not impose penalties until the third cluster study cycle (including any transitional cluster study cycle) after the effective date of the

Continued on page 6

FERC/Federal News

FERC Interconnection Rule Sets Penalties, Ends 'Reasonable Efforts' Standard

Commission Shows Frustration over Transmission Providers' Missed Deadlines

Continued from page 5

transmission provider's compliance filing.

The commission also will waive penalties for studies submitted within a 10-business day grace period and will allow a deadline extension of 30 business days by mutual agreement of the transmission provider and all affected interconnection customers. Penalties will be capped at 100% of the initial study deposits.

FERC rejected the NOPR's proposed *force majeure* penalty exception, instead saying that transmission providers will be permitted to appeal penalties to the commission.

"Transmission providers may explain in any appeal to the commission any circumstances that caused the delay, including any events that qualify as *force majeure*, and the commission will consider such circumstances as part of its evaluation of whether good cause exists to grant relief," FERC said.

RTOs and ISOs will be allowed to submit a Federal Power Act Section 205 filing to recover penalties from at-fault transmission providers.

"Non-RTO/ISO transmission providers and transmission-owning members of RTOs/ISOs may not recover study delay penalties through transmission rates," FERC said. "… Because the at-fault transmission provider's shareholders will pay the penalty, this prohibition addresses commenters' concerns that study delay penalty costs will ultimately be borne by customers and ratepayers through increased transmission costs."

Transmission providers will be required to make quarterly postings making public the penalties incurred from the previous quarter.

Other Studies Rejected

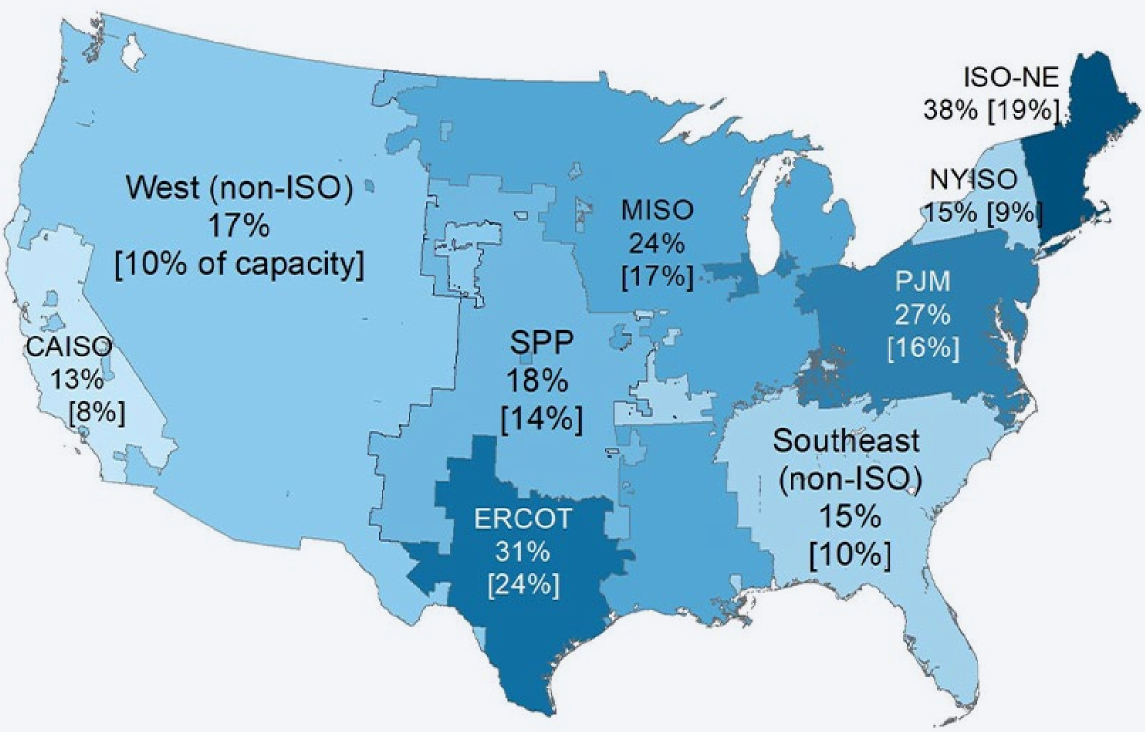
The commission rejected NOPR proposals for optional resource solicitation studies or optional informational interconnection studies and adopted a modified proposal to require evaluation of certain advanced transmission technologies. The commission said those changes "should reduce the burden on transmission providers as compared to that under the NOPR."

The NOPR sought comment on whether state agencies required to develop a resource plan or conduct a resource solicitation process should be defined as a resource planning entity and be able to request initiation of an optional resource solicitation study.

But the commission concluded there was "insufficient evidence" to justify the optional resource solicitation study as a "generic solution" across all regions for coordinating state-level resource planning with the interconnection process, noting that many transmission providers do not have load-serving entities that conduct resource solicitations.

"We are also concerned that the particular 'one size fits all' approach proposed in the NOPR would create uncertainty regarding the cost and timing of interconnecting to the transmission system, because the proposed study would not result in useful network upgrade cost estimates."

It said it agreed that the proposal "would divert transmission provider resources and potentially lead to delays." ■



Share of projects requesting interconnection that reached commercial operations from 2000-2017, with capacity-weighted completion rates in brackets. Only ISO-NE and ERCOT exceed 30% completion. | *Lawrence Berkeley National Laboratory*

FERC/Federal News

FERC Calls for More Info on Order 881 Compliance Timelines

Ruling is Similar to April, June Findings

| © RTO Insider LLC

FERC issued another set of rulings on Order 881 compliance filings Thursday, ordering seven transmission providers to give more information on their timelines for calculating or submitting ambient-adjusted ratings (AARs). The commission accepted the other aspects of the transmission providers' filings.

The affected transmission providers are GridLiance Heartland (*ER22-2355*), GridLiance High Plains (*ER22-2354*), Florida Power & Light (*ER22-2353*), Cube Yadkin Transmission (*ER22-2466*), Versant Power (*ER22-2358*), Nevada Power Co. (*ER22-2304*) and Cheyenne Light, Fuel and Power (*ER22-2307*).

The filing parties have until Nov. 12, 2024, to submit their timeline information, eight months before the July 2025 Order 881 implementation date. FERC said this extended due date accounts for the fact that it may be easier for transmission providers to submit AAR timelines closer to the 2025 implementation date.

This ruling is similar to previous FERC findings in April and June of this year. (See *FERC Approves Batch of Line Ratings Compliance Filings* and *Order 881 Timelines Need Explaining, FERC Says*.)

Order 881 requires transmission owners and operators to implement AARs — essentially real-time transmission line ratings — for short-term transmission requests on lines affected by air temperature, while requiring seasonal ratings for long-term service (*RM20-16*). FERC has said that existing static ratings based on worst-case weather assumptions limit the available transmission capacity and that the changes mandated by Order 881 will help free up a significant amount of capacity on the grid. (See *FERC Orders End to Static Tx Line Ratings*.) ■

— Jon Lamson

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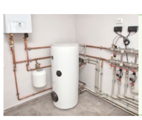

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FERC/Federal News

Members of Congress Debate Transmission Permitting

AEU Event Coincides with Senate ENR Hearing on Permitting on Federal Lands

By James Downing and Michael Brooks

Congress has been talking about changing permitting laws this year, but it's still unclear whether the two parties will be able to strike a deal, speakers said at an event Wednesday hosted by *The Hill* and Advanced Energy United at the National Press Club in D.C.

Sen. John Hickenlooper (D-Colo.) is working on the BIG WIRES Act, which would require minimum transfer capability between regions. That would benefit the entire country by making cheaper power supplies available and facilitating the shipping of more power to regions facing reliability crises, he said at the event.

"Certainly, it's a steep hill these days, because both sides are worried about giving any advantage to the other side, rather than solving the problems," Hickenlooper said. "I think the BIG WIRES is about trying to make sure that we can get the power to where it's needed."

That and other reforms are being debated, but the question is whether Congress can actually pass them — either on their own, or as part of some must-pass legislation, as happened with the first bite of the apple during the debt ceiling showdown. (See *Debt Ceiling Bill Provides Mini-deal on Permitting*.)

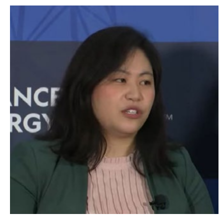
"I haven't given up my hope for this Congress right now," said Rep. John Curtis (R-Utah). "There are some great ideas out there."

Any policies that do wind up getting past the Republican side at least will have to go through "regular order," meaning the relevant committees will have to examine them and pass them, even if they go into some kind of must-pass budget deal, he added.

"There's something therapeutic for a member, if he doesn't understand an issue, that it's gone through committee hearings, that his colleagues have had a chance to digest it; to read every line and study every line; and that they support it," Curtis said.

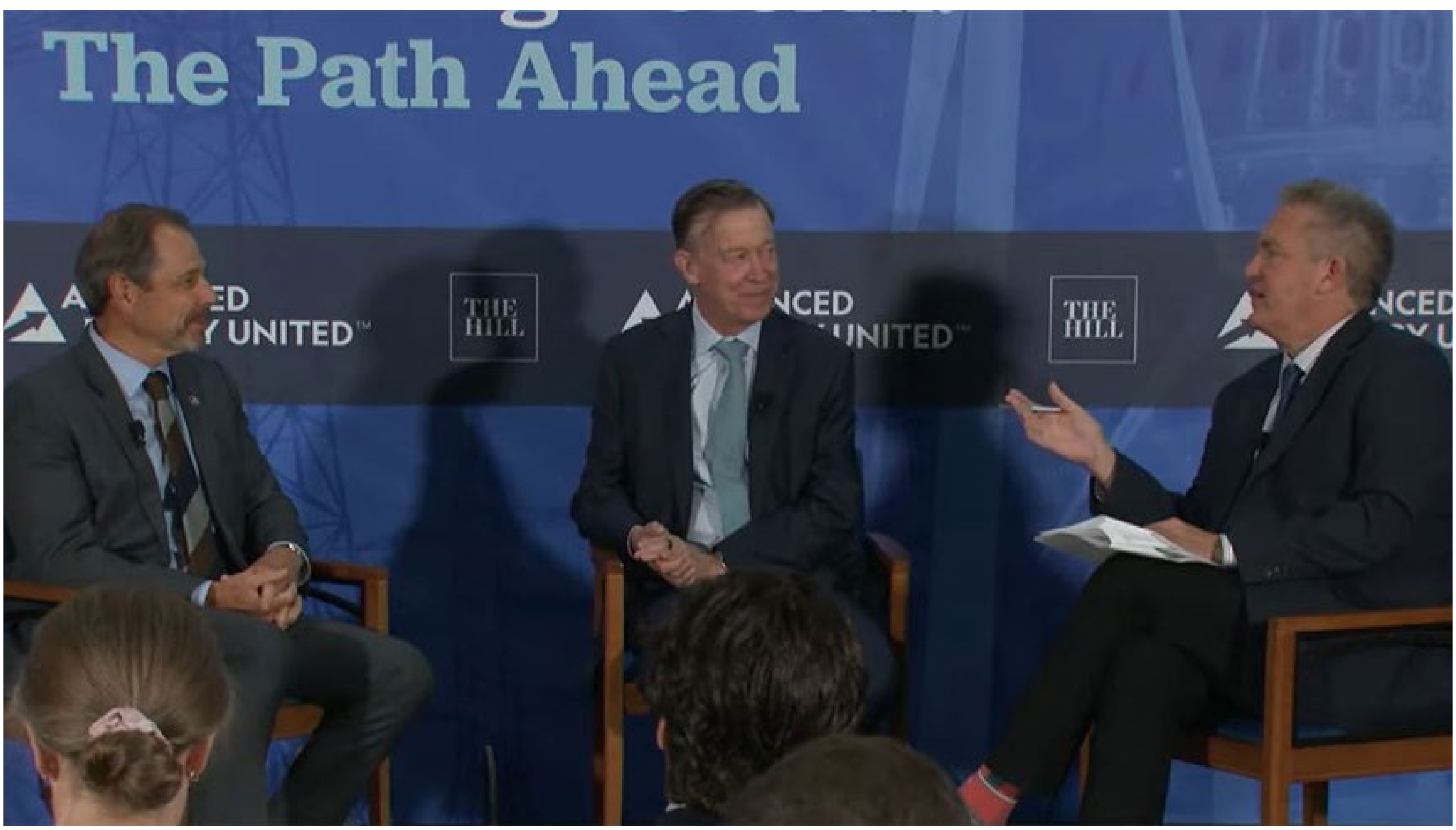
Final rules from FERC on transmission planning and implementing its new backstop siting authority are still pending. While Hickenlooper noted the commission might be able to act faster than Congress, Curtis argued regulatory changes could prove transitory.

"If we don't do it, legislatively, it's not permanent," Curtis said. "And it's subject to change. ... If we get a different administration, in two years, you're starting over. And I think it's harder to do it legislatively, but it's more long-lasting if we can do it."



Maria Robinson, DOE | *The Hill*

FERC is not the only agency working on the issue, with the Department of Energy's Grid Deployment Office in charge of $26 billion in spending to help expand the transmission grid, said its director, Maria Robinson. With new factories and other sources of demand sprouting up around the country, along with major changes in power supply, new transmission needs to be built.



From left: Rep. John Curtis (R-Utah); Sen. John Hickenlooper (D-Colo.); and Bob Cusack, editor-in-chief of *The Hill* | *The Hill*

FERC/Federal News

"Now part of this is, transmission is not cheap," Robinson said. "I think that's something that we can all agree on. And we want to make sure that we're planning appropriately, whether it's across different regions or across different state lines, to make sure that we're doing it really efficiently and cost effectively for the American people so that no one is paying for lines that are duplicative or unnecessary."

For too long, planning the grid has been too *ad hoc* and decentralized, with transmission plans focused on curing immediate reliability needs and not paying attention to the future, said Kyle Davis, director of U.S. federal policy for Enel North America.

"It's good news that people are even uttering the word 'transmission' in the halls of Congress," Davis said. "For those of us that have been working on this issue for over 10 years or so, it is refreshing. I think the hope is that we can get some real fundamental movement and sort of comprehensive transmission investment strategy for the United States."

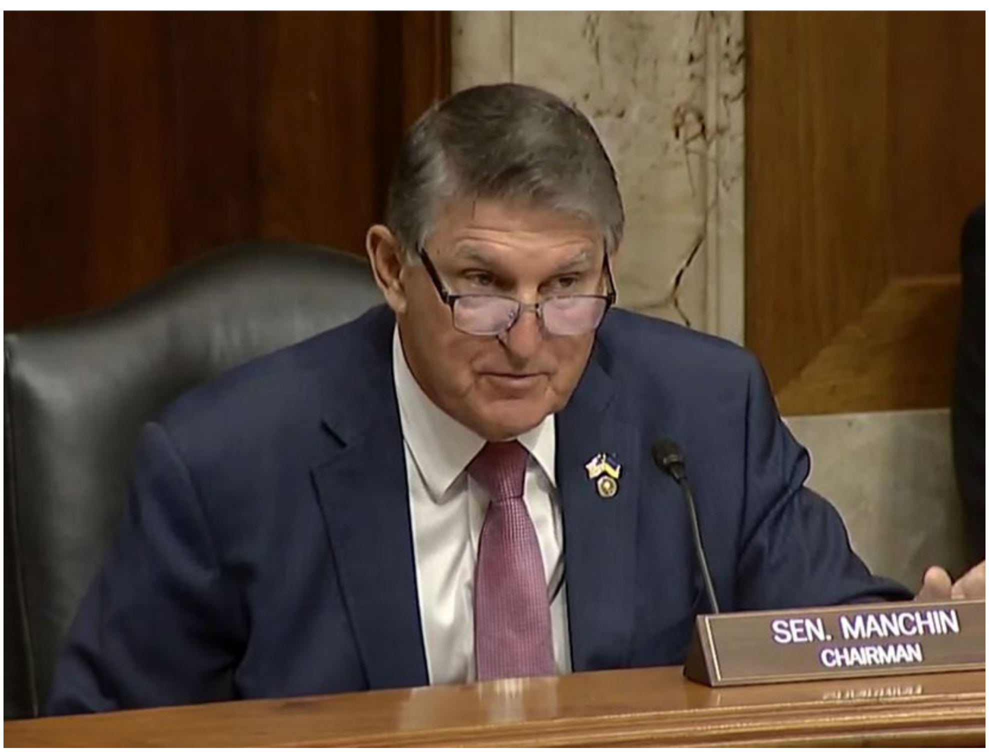
Permitting on Federal Land

Meanwhile, members of the Senate Energy and Natural Resources Committee debated permitting reform on federal lands. Much of the hearing Wednesday was devoted to oil and gas permitting, but Chair Joe Manchin (D-W.Va.) made sure to include transmission in the discussions.

From left: former Maryland PSC Chair Jason Stanek; Antonio Smyth, AEP; and Chad Teply, Williams Companies | *Senate ENR Committee*

"Over the last year there has been an attempt to paint transmission permitting reform as just another subsidy for intermittent renewable energy," Manchin said in his opening statement. "If that were the case, then that would be very hard for a lot of us to support. But this simply isn't true, and we should not politicize infrastructure that has long enjoyed bipartisan support."

Manchin argued the importance of transmission for reliability, "particularly during weather events that span hundreds of miles. Long-distance transmission and interconnectivity enables power to move to where it's needed. And as we've seen in Texas and other parts of the country, the areas that need the power aren't just blue states with aggressive climate targets that some of us may not agree with."



Sen. Joe Manchin (D-W.Va.) | *Senate ENR Committee*

Ranking Member John Barrasso (R-Wyo.) agreed, somewhat.

"The biggest threat to reliability is not the lack of transmission lines. It is the premature retirement of coal, natural gas and nuclear power plants," Barrasso said in his opening statement. "Congress should not try to force electric customers in rural, inland states, such as Wyoming and West Virginia, to subsidize ill-conceived policies of coastal states, such as California and New Jersey. If California, New Jersey or New York want to rely on offshore wind, then their customers should pay for it."

Manchin noted that while the debt ceiling deal limited environmental reviews under the National Environmental Policy Act, judicial proceedings over those reviews still can tie up projects long after they've been approved. Witnesses at the hearing generally agreed that it was necessary for Congress to set tighter deadlines for parties to file challenges, for courts to reach decisions and for agencies to fix the issues identified by the courts.

"I think a shot clock is important," former Maryland Public Service Commission Chair Jason Stanek said. "Legal due process for the state who is out of favor is important ... but that should not go on *ad infinitum* for potentially years at a time, so I think a statute of limitations is necessary." ■

FERC/Federal News

Senate Committee Looks into Climate Change's Grid Impacts

By James Downing

Climate change is already causing billions of dollars in economic costs and damage to infrastructure, including the power grid, the Senate Budget Committee heard at a hearing Wednesday.

"Our power grids are seeing record-breaking demand and reduced power efficiency, as well as added sea level rise risk where infrastructure — especially thermal power plants — is located along the coast," said committee Chair Sheldon Whitehouse (D-R.I.). "Extreme weather is responsible for 78% of the major disruptions to our power system. Since 2015, the frequency of major blackouts has doubled."

During an average year, power outages can cost about $44 billion, but that can be doubled or more because of major climate impacts, he added.

Winter Storm Uri in February 2021 knocked out power to millions in Texas and surrounding states, leading to at least 246 deaths and damages ranging from $80 billion to $130 billion, said Analysis Group Senior Adviser Susan Tierney. In December, Winter Storm Elliott cut power to hundreds of thousands on the East Coast and knocked out a quarter of the generation in PJM (although the RTO kept the lights on in its territory). (See *PJM Recounts Emergency Conditions, Actions in Elliott Report*.)

"Before it could no longer do so, PJM had been exporting power to neighboring utilities in the Tennessee Valley Authority region and the Carolinas where rolling blackouts were underway," Tierney said in written testimony.

Extreme heat and drought have also tested the energy systems, as have wildfires, hurricanes and other events.

"Due to the changing climate, the energy system is projected to be increasingly threatened by more frequent, longer-lasting power outages affecting critical energy infrastructure and creating fuel shortages," she added.

Hurricane Katrina in 2005 showed what could happen when a major storm wreaks havoc on key energy infrastructure — cutting one-third of domestic oil production and one-sixth of natural gas production.

"U.S. oil and gas prices were double the national average for months and it raised the national cost of natural gas on the order of $50 billion in the 10 months after the storm," said Tierney.

That hurricane led to a major policy change in Louisiana, its first "Comprehensive Master Plan for a Sustainable Coast." The plan, which has been updated three times since then, has already produced benefits, said Gov. John Bel Edwards (D).

"The Coastal Master Plan is a $50 billion, 50-year roadmap that prioritizes our investment in coastal infrastructure," Edwards said. "The plan reflects the best available science, accounting for changes on the ground and forecasting what is at risk in the future."

If the plan is properly implemented, Louisiana could have less at risk from sea rise and related storm risks in 50 years than it does today, he said. Without action, the state would lose thousands of square miles of coastline and increase its vulnerability to storms, he added.

After Katrina, the levees and other protections around New Orleans got a $14.5 billion upgrade. It did not fail during several hurricanes since and thus has saved billions in damages, Edwards said.

This month marks the 20th anniversary of another major energy disruption — the Northeast Blackout, which left 50 million without power for up to two days in what was the most widespread blackout in North American history, said ITC Holdings CEO Linda Apsey.

"It was a sobering reminder of how vulnerable our nation's energy security can be when we fail to adequately invest in transmission infrastructure," Apsey said. "This event served as the impetus for regulators and energy providers to put safeguards in place that have made our grid more reliable and resilient than it was before."

Although the industry has improved since then, the country needs to update how transmission is built to better secure the grid, Apsey said.

"Building transmission can take up to a decade, if not more — a pace nowhere near fast enough to meet the [Biden] administration's clean energy goals," Apsey said. "It's imperative that we examine changes to ensure that investment in transmission is predictable, timely and cost-effective in order to realize the benefits of a modern transmission grid."

Making it easier to build transmission lines so they do not get delayed by years of litigation and permitting disputes is going to be a key part of that effort, she added.

MISO's Cardinal-Hickory Creek Line, which is planned to run 102 miles from Iowa to Wisconsin was part of the original Multi-Value Projects (MVP) in 2011, but it has yet to be built due to permitting concerns over the 1.3 miles that crosses federal land, said Apsey. The courts recently cleared the way for federal permitting authorities to approve the project and ITC is ready to start work when they do.

"Over 100 renewable energy projects are awaiting completion of the Cardinal-Hickory project in order to interconnect to the grid, resulting in hundreds of millions of dollars in lost energy savings to customers," Apsey said. ■

Louisiana Gov. John Bel Edwards (D), Analysis Group's Susan Tierney, Tulane University professor Jesse Keenan and ITC Holdings CEO Linda Apsey testify at the Senate Budget Committee on July 26. | *Senate Budget Committee*

FERC/Federal News

FERC Accepts Niagara's Cost Recovery Plans, Orders Rate Proceeding

Commissioner's Concurrence Emphasizes Public Policy Costs

FERC on Friday approved Niagara Mohawk Power's construction recovery requests for the Smart Path Connect project while partly accepting its rate schedule revisions.

The commission also ordered a proceeding to determine the justness of its proposed transmission service charges (*ER23-973/ER23-974*).

The National Grid subsidiary *sought* to recover all costs from the construction work in progress costs for the Smart Path project it is building alongside the New York Power Authority, as well as revise its RS15 mechanism and create a new RS18 requirement, which set rates for transmission service charges and establishes a Smart Path charge recovery standard, respectively.

FERC accepted Niagara's Smart Path cost allocation plan and its request for construction cost incentives, as well as the RS18 proposal, but only partly accepted the proposed RS15 revisions.

Smart Path would rebuild roughly 100 miles of 230-kV transmission lines, replacing them with either 230-kV or 345-kV lines and upgrading associated substations, creating a continuous 345-kV path from northern New York to the downstate region to mitigate congestion. The project was designated a "priority transmission project" by the state's Public Service Commission and was one of the key products to come out of the Climate Leadership and Community Protection Act.

FERC previously rejected Niagara's Smart Path cost allocation and recovery plans, but the utility adjusted its proposal to create RS18, which sets a 10.3% return on equity and applies a capital structure that becomes possible if the RS15 revision to add a project-specific

FERC's D.C. headquarters | © *RTO Insider LLC*

incremental formula rate to the mechanism is accepted as well. (See *FERC Rejects Niagara Mohawk Tx Cost Formula, ROE Adders*.) NYISO submitted these filings on behalf of Niagara.

Niagara also proposed a 20% ROE cost containment mechanism for when actual costs exceed the $481.9 million project cost cap.

The commission approved the utility's RS18 proposal to allocate Smart Path's costs on a statewide volumetric load-ratio share basis, noting that it "accepted a similar participant funding agreement allocating costs for local transmission projects needed to meet the CLCPA."

FERC also accepted RS15 revisions that comply with Order 864, which required transmission providers to revise their formula rates to account for changes caused by the Tax Cuts and Jobs Act of 2017.

However, after finding that the part of the RS15 proposal related to the allocation of general plant and administrative expenses "raises issues of material fact that cannot be resolved based on the record before us," the commission ordered hearing and settlement proceedings to address the matter.

Concurrence

Commissioner Mark Christie *wrote* a concurrence emphasizing that Friday's order does not suggest that one state's public policy costs can be forced onto consumers in another.

Christie wrote that "costs related to a public policy project — which the Smart Path Connect Project is — should be borne by the sponsoring state and not shifted to consumers in other states."

"That is how democracy is supposed to work," he added.

"There is nothing in the record in this matter to indicate that any of the costs of the transmission projects that will be built to implement New York's public policies under the terms described in this proposal will be forced on consumers in other states," he said.

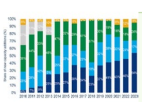
"Any suggestion that this order can be read to permit shifting a state's public policy costs to consumers in other states or to suggest that the consumers in other states benefit from those projects without the express agreement of those other states is incorrect and it is not the order I support here or would have supported here," Christie concluded.

The proposals accepted by FERC became effective April 1. National Grid estimates that Smart Path's total capital cost will be $1.2 billion and its in-service date will be December 2025.

The company declined to comment on the ruling. ■

— John Norris

National/Federal news from our other channels



WoodMac: New Solar Hits 54% of New Generation in US in Q1

NetZero Insider

MVP Southgate Extension Request Gets Mixed Reception at FERC

NetZero Insider

Summit Showcases New Technologies to Accelerate Industrial Decarb

NetZero Insider

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CAISO/West News

Proposed New Western RTO Discussed at CREPC

By Hudson Sangree

Utility regulators from Oregon and California discussed their proposal for a new independent RTO covering the entire West for the first time publicly during last week's summer meeting of the Committee on Regional Electric Power Cooperation (CREPC).

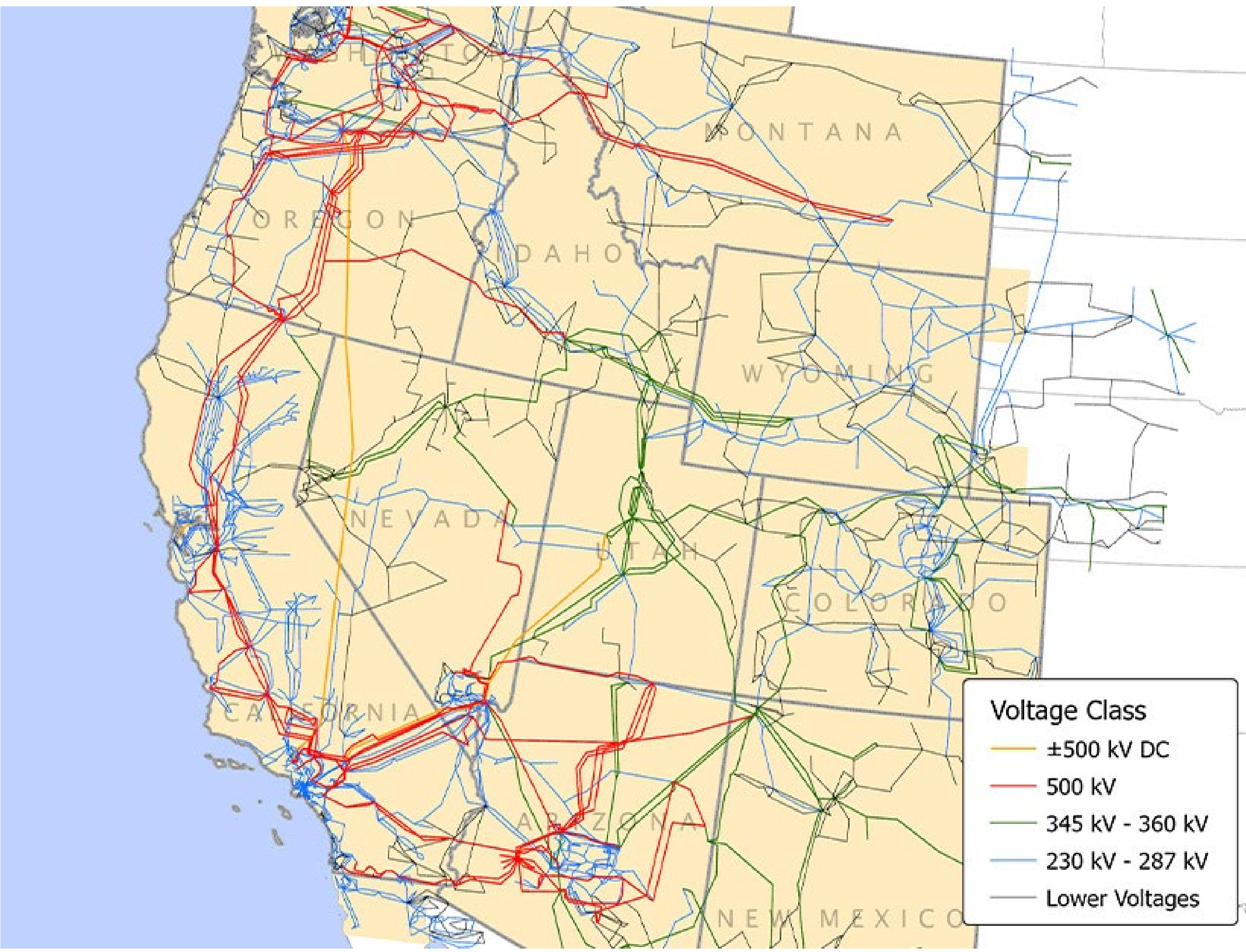
The proposal was first described in a July 14 *letter* signed by regulators from Arizona, California, New Mexico, Oregon and Washington and sent to the chairs of the Western Interstate Energy Board (WIEB) and CREPC, which has become a forum for discussing Western market development. (See *Regulators Propose New Independent Western RTO*.)

Mark Thompson, a member of the Oregon Public Utility Commission and a signer of the letter, told CREPC that the proposal originated from a desire to pursue the benefits of a full Western market and not see the West "fractured" by competing market proposals by SPP, CAISO and possibly others.

SPP and CAISO have offered competing day-ahead market proposals, and SPP is developing a Western version of its Eastern RTO, called RTO West, to compete with CAISO, which lacks independent governance. (See *Western Day-Ahead Markets Debated at CREPC-WIRAB*.)

"The idea was that perhaps we can form an entity in the West that would have independent governance shared across all states, and that the entity could eventually become the delivery arm for some of the programs that we already have through the CAISO, including the [Western] Energy Imbalance Market, perhaps the EDAM as well," Thompson said, referring to CAISO's proposal for an extended day-ahead market for the WEIM.

"Ultimately, that entity could create an independently governed full market opportunity for the West that all states could join, including California," he said. "The vision would be that rather than fracture the market, let's stand up



A state-led study found that an RTO covering the entire U.S. portion of the Western Interconnection could save the region $2 billion in annual electricity costs by 2030. | *WECC*

CAISO/West News

another entity to at least be a vessel that can deliver a full market opportunity and that can have independent governance that all Western states could join in."

Alice Reynolds, president of the California Public Utilities Commission, also signed the letter and helped develop the proposal, which she called an initial "invitation for all states that are interested to discuss and consider this concept."

"I really do share the view that the fundamental driver of this working group idea and consideration of the concept is the recognition that customers across the West will benefit significantly from a West-wide market," Reynolds said at the CREPC *meeting*. "As regulators, this is a common goal that we share — affordable rates, and increased Western cooperation can help us advance that."

A June 2021 study found an RTO covering the entire U.S. portion of the Western Interconnection could save the region $2 billion in annual electricity costs by 2030 and cut carbon dioxide emissions by 191 million metric tons. Utah Gov. Spencer Cox's Office of Energy Development led the study along with energy offices in Colorado, Idaho and Montana. (See *Study Shows RTO Could Save West $2B Yearly by 2030*.)

The WEIM has produced nearly $4 billion in cumulative benefits for participants since its founding in 2014, she noted.

"The discussion of a new concept, a West-wide entity with independent governance, really gives us an opportunity to build on this and to ensure that customers are getting the benefit of the full range of possible services and benefits that can be achieved through West-wide cooperation," she said.

Others who signed the letter included Washington Utilities and Transportation Commission members David Danner, Milt Doumit and Ann Rendahl; Oregon Public Utility Commissioner Letha Tawney; Arizona Corporation Commission member Kevin Thompson; Pat O'Connell, chair of the New Mexico Public Regulation Commission; and Siva Gunda, vice chair of the California Energy Commission.

"We have identified a common commitment in seeking the benefits shown in multiple studies that demonstrate the most favorable electricity market for consumers is one that includes a West-wide market footprint," the letter said. "Such a market would avoid the issue of 'seams' from separate markets across major portions in the West and result in optimized use of resources to meet loads across the entire interconnection."

The new entity could contract with CAISO as a regional transmission operator and assume control of the WEIM and EDAM, it said.

'Larger Conversation'

CREPC allotted 20 minutes for the presentation by Reynolds and Thompson and a brief question-and-answer session.

One question was whether the Canadian provinces in the Western Interconnection could join the RTO.

"I don't see any reason to limit it to states," Reynolds said. "We need a collective term that's broader" than a Western RTO.

Utah Public Service Commissioner John Harvey asked about the potential costs of establishing a new entity.

"I'm an economist by training, and I'm curious and worried about the idea that if a whole new entity is created, you're adding a tremendous amount of transaction costs," Harvey said. "Just looking at CAISO or SPP, there's a huge infrastructure there to try and settle these markets and determine the pricing and settle the accounts. Duplicating that again could burn up a lot of those benefits."

He also said states with lower energy costs might not want to join an RTO.

"They would tend to say that the EIM and the day-ahead market give them the opportunities they need, and they don't really see much benefit to moving beyond that," he said.

Reynolds replied, "I think that's part of the conversation that we want to have around this concept. If states are feeling like, 'Well, wait a minute, we're good with EIM and EDAM,' then that's certainly relevant to next steps."

To Harvey's first question, she said, "the idea of this is not to add costs, but to take advantage of investments that have already been made and then build on those."

There was not time to answer questions from other participants.

CREPC Co-Chair Megan Decker, who is also chair of the Oregon PUC, said the committee would convene a follow-up meeting.

"It seems to me this is something where CREPC could convene a larger conversation to answer some of the questions that we didn't have time for in 20 minutes today," Decker said. ■

CCAs Challenge California PUC on RA Ruling

Decision Prohibits a CCA from Expanding Territory for 2 Years After RA Deficiency

By Elaine Goodman

A group representing California's community choice aggregators is asking regulators to reconsider a decision that blocks CCAs from expanding if they have had resource adequacy deficiencies in the past two years.

The California Public Utilities Commission on July 5 issued the *decision*, which adopts local capacity obligations for 2024 to 2026 and refines the commission's resource adequacy program.

The California Community Choice Association (CalCCA) filed a *rehearing request* Wednesday, saying the decision contained numerous "legal errors."

CalCCA argues that the CPUC exceeded its jurisdiction over CCA implementation plans and impaired customers' right to aggregate their loads with a CCA. The commission failed to act in a nondiscriminatory manner by prohibiting expansion of CCAs and electric service providers, but not investor-owned utilities, CalCCA said.

"The CPUC has given itself new unauthorized powers to needlessly discriminate against CCAs and prevent their growth," CalCCA Executive Director Beth Vaughan said in a statement. "The decision literally blocks communities from exercising their legal right to aggregate and provide customers with a choice of energy providers."

California has 25 CCA programs in operation, serving more than 14 million customers. The CCAs buy electricity for participating communities, in place of investor-owned utilities, with an emphasis on clean energy.

California has 25 CCA programs in operation, serving more than 14 million customers. | *CalCCA*

RA Obligations

The CPUC said in its decision that load-serving entities have been failing to meet resource adequacy obligations. The decision said seven LSEs had month-ahead deficiencies in 2021 and five in 2022. Some LSEs have repeatedly failed to meet their RA obligations, the decision said.

"Even more concerning, some LSEs submitted implementation plans to expand their customer load by increasing their service territory, even as they have been unable to secure sufficient capacity to meet their RA obligations and serve their existing customers," the decision said.

Under the decision, an LSE isn't allowed to expand its service territory if it hasn't complied with RA requirements in the previous two calendar years. A deficiency doesn't count toward the expansion ban if it's less than 1% of the LSE's requirements.

The restriction applies to a CCA's expansion of its service territory, not to growth within its existing territory.

The CPUC decision addresses the nondiscrimination issue by noting that investor-owned utilities are providers of last resort and therefore legally distinct from other LSEs.

CalCCA said the CPUC may or may not rule on its rehearing request. If there's no ruling by Sept. 26, the request is considered denied. The group said it would then decide whether to take the issue to a state appeals court.

Penalty System

The CPUC sets resource adequacy obligations for LSEs that are enforced through citations and fines.

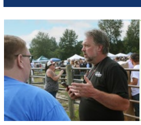
In a previous decision, the CPUC added a point accrual system to the program's penalty structure to increase penalties when an LSE repeatedly falls short of RA obligations.

CalCCA said newer market entrants such as community choice aggregators and direct access providers are hardest hit by resource shortages. In contrast, investor-owned utilities have "legacy" supplies, the group said in a resource adequacy section on its website.

CalCCA said the CPUC should do more to address the RA problem.

"RA penalties for LSEs unable to secure supply in a deficient market do nothing to get new resources in the ground, and they unnecessarily add to customer costs and indirectly increase the cost of supply," CalCCA said. ■

West news from our other channels



Petition Drive Seeks to Repeal Wash. Cap-and-trade Program

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CAISO/West News

'Uncertainty' Prompts CAISO to Declare Another EEA Watch

Source: Industry Participants Speculating on Alert Causes

By Robert Mullin

CAISO declared an energy emergency alert (EEA) watch for a second straight day Wednesday, citing "uncertainty" about energy supply and load forecasts, transmission constraints and high electricity demand in the Western U.S.

Wednesday's announcement came on a day when system load was expected to peak at a relatively modest 42,659 MW, while CAISO's neighbors in the desert southwest continue to swelter in a record-setting heat wave. The ISO said the watch would remain in effect from 6 to 10 p.m. PT.

"CAISO analysis shows that all available resources are committed or forecasted to be in use, for the specified time period, and there is potential for an energy deficiency," the ISO said in a notice posted Wednesday afternoon. "Entities are encouraged to offer available energy and ancillary service bids, [and] participating customers may be directed by utilities to use generators approved for emergencies, or to reduce load according to the protocols of each utility's program."

The ISO declined to comment beyond a *press release* it issued Wednesday afternoon and did not specify the location of the transmission constraints mentioned in its notice.

"No further emergency declarations are planned at this time, but if grid conditions worsen, the ISO could declare an EEA 1, 2 or 3," the release said.

A source familiar with Western grid operations, but who is not authorized to speak on behalf of their company, said there has been "lots of speculation" among industry participants about what is causing the ISO to issue the alerts, but "nothing conclusive or pointing to a single issue."

"It's worrying, particularly since [CAISO] said they were good and had good water this year," the source said.

An EEA watch represents a preliminary step before the ISO declares an actual emergency, which will range from calls for conservation measures and demand response under an EEA 1 to a need for rotating blackouts under an EEA 3.

CAISO declared its first EEA 1 of the summer last month, when it confronted a shortfall of ramping resources needed to firm up the grid as solar output rolled off the system during the evening of July 20. The ISO that day was forced to ask for conservation and invoke DR despite moderate summer loads and normal temperatures in California's major population centers.

CAISO cited transmission constraints as one of the reasons for calling an EEA watch for Wednesday evening. | © RTO Insider LLC

A CAISO spokesperson told *RTO Insider* after the event that the grid operator would make "adjustments going into the next peak hours" to account for the forecasting issues leading to the emergency. (See *Ramping Shortfall Sparks CAISO's 1st Summer Emergency*.)

But Wednesday's EEA watch, which followed another such watch issued the previous evening, signals that CAISO could be struggling to manage moving parts that are creating operational uncertainty even under conditions that should translate into smooth grid operations — such as abundant hydro in the system and a record-breaking 5,600 MW of battery resources to assist with evening ramps.

The July 25 watch, which lasted from 7:26 to 11:59 p.m., occurred on a day when CAISO's load peaked at 43,386 MW at 6:30 p.m., compared with a day-ahead peak forecast of 42,421 MW. But by 7:45 p.m., as solar came off the system, net load was peaking at 38,564 MW, more than 1,800 MW above the day-ahead forecast for that interval. Net load continued to outpace day-ahead forecasts into the night, at one point by as much as 2,923 MW.

At the same time, according to CAISO daily reports on curtailed and non-operational generators, the ISO was dealing with a sharp increase in forced outages, which jumped from 10,436 MW on the morning of July 24 to 11,721 MW the next morning. Next-day generation summaries for July 25 showed that a few key resources with ramping capability were also curtailed in the late afternoon and early evening, including 407 MW from Pacific Gas and Electric's Helms pumped storage plant because of transmission constraints and about 300 MW from Calpine's gas-fired Los Medanos facility because of "plant trouble."

The ISO reports also showed that San Diego Gas & Electric's gas-fired Palomar Energy Center returned to service at about 6 p.m. July 25 after a four-day outage, only to be quickly shut down, taking its 588 MW back out of the system just ahead of the evening ramp.

Wednesday's morning outage report showed 11,605 MW of curtailments across the ISO, down slightly from the previous day. ■

CAISO/West News

Transmission Spending Should be 'Like Going to Costco'

Western States Initiative Weighs Transmission Needs and Barriers

By Hudson Sangree

Developing transmission in the West should involve a long-term, comprehensive plan instead of a localized piecemeal approach, speakers agreed at last week's webinar of the Western States Transmission Initiative – an effort led by Gridworks and former FERC Chair Richard Glick for the Committee on Regional Electric Power Cooperation (CREPC).

The second in a three-part *series*, the webinar addressed the West's transmission needs and barriers to transmission development.

Glick, now a senior fellow at Gridworks and head of his own *consulting firm*, moderated a panel discussion with Rob Gramlich, president of consultant Grid Strategies, and Kris Raper, vice president of strategic engagement and external affairs at WECC and a former member of the Idaho Public Utilities Commissioner.

Gramlich and Raper both said that the West needs better regional planning to maximize the value of transmission built and avoid wasteful spending.

"I think you can look at the numbers and say, 'a purely reactive short-term, just-in-time transmission approach is the most expensive way to do transmission,'" Gramlich said. "And we really are in most of the country doing just-in-time transmission."

Building transmission to ensure grid reliability in the short term is necessary, but "if we proactively plan, we can almost certainly find a cheaper way to build a future system," he said.

"From a consumer perspective, I think we need to do everything we can to move to more efficient operation of the existing grid and then plan for future needs," Gramlich said. "And then I think the most important cost containment is to do good planning that does good, solid, benefit-cost analysis of what are the benefits, what are the costs. Let's look at the portfolio, not the specific projects alone. Let's look at the regional efficiencies and get the economies of scope brought in to bear."

"There's been a lot of transmission investment in the country, but most of that is on local systems," he added. "There's been almost none on the large regional and interregional [scale] over the last decade."

Raper said large amounts of up-front spending on transmission could be difficult to sell to consumers and state regulators concerned about rising costs. But she suggested using a simple analogy to explain why it makes sense.

"It's like going to Costco to buy things," Raper said. "If you go to the regular grocery store, you buy for the short-term generally. And per item, you're probably going to spend a little more. But if you have the ability to go to Costco, are you spending more upfront when you go there? Yes, but it lasts you longer."

"From the most simplistic standpoint of explaining to a consumer," planners could say, "yes, it looks like a lot of money, but if we do it onesie-twosie, you're actually spending more, because you don't gain the efficiencies from buying at Costco," she said.

Raper outlined WECC's efforts to study Western transmission needs in the next 20 years and interregional transfer capabilities, as required by recent federal law. (See *NERC FAC Approves Transfer Study Funding*.)

A WECC four-part study process is underway to study transmission needs, including during extended periods of extreme heat and cold in the West. Four scenario studies could be finished this year, with the 20-year analysis to be completed in 2024.

"We are working to develop a process for building out our 20-year planning model," Raper said. "We think it'll be valuable both for longer term transmission planning and reliability assessments of the West, and also to meet evolving FERC expectations that have come out recently under proposed rules that are focused on improving regional transmission planning processes."

As an impartial entity that oversees reliability across the entire Western Interconnection, WECC's long-term transmission analysis may carry more weight with regulators in Western states, where views on the need for green energy and transmission development can vary widely.

"We're excited about the growing dialogue regarding transmission needs," Raper said. "We see the urgency as now, and we do believe that with our stakeholders, we've identified a way for WECC to fill an important void in the conversation, providing a high-level, interconnection-wide view of transmission needs."

"All of this has been done with the objective of maintaining our independent voice of reliability, remaining policy-neutral and resource-agnostic and fitting within WECC's delegated authority to perform reliability assessments for the Western Interconnection," she said.

The first webinar in the WSTI series on July 20 dealt with transmission planning. The third and final webinar in the series on Aug. 16 will tackle cost allocation.

"I look forward to seeing you all again on Aug 16 for a discussion of ... who pays for transmission and how much do they pay," Gridworks Director Kate Griffith said. "And perhaps we'll get a little bit deeper into Kris's analogy of spending our money at a transmission Costco instead of a fancy food store." ■

| KKPCW, CC-BY-SA-4.0, via Wikimedia Commons

ERCOT News

ERCOT Demand Breaks 83 GW with Latest Record

ERCOT again saw load reach record levels Monday as searing heat continues to bake the already well-done region.

Average load exceeded the 83 GW barrier for the first time when it hit 83.05 GW during the hour ending at 5 p.m. That broke the mark of 82.89 GW, set one hour earlier, which bettered the old record of 82.59 GW established July 18.

Solar resources again carried a heavy load for ERCOT during the afternoon, producing a near-record 13.35 GW of energy. Solar set a new high Friday when it peaked at 13.42 GW.

Average hub prices were settling at $379.84 in late afternoon, although plant outages were not an issue.

The Texas grid operator is projecting demand to exceed 85 GW today and to peak above 83 GW for the rest of the week. Average demand has been above 80 GW 61 times this summer after reaching that mark just once last year.

The National Weather Service on Sunday issued an extreme heat warning for much of North Texas; temperatures in the Dallas area are expected to hit 107 degrees Fahrenheit today.

In far West Texas Sunday, temperatures only reached only 97 degrees in El Paso, ending a string of 44 straight days over 100. Austin, in Central Texas, has an active streak of 24 straight days over 100. ■

— Tom Kleckner

Temperature reading in Giddings, Texas | © *RTO Insider LLC*

ISO-NE News

DC Circuit Upholds Tx Cost Allocation for Rhode Island Solar Project

By Jon Lamson


The Iron Mine solar project, owned and operated by Green Development | *Green Development*

The D.C. Circuit Court of Appeals on Friday *denied* a pair of petitions by the Rhode Island-based company Green Development over *FERC*'s approval of transmission charges connected to a proposed solar project. The court determined that Green Development's four main issues with FERC's approval lacked merit.

Green Development is the developer of four solar projects totaling about 40 MW in Rhode Island. The company requested to connect the projects to the local distribution system, owned and operated by Narragansett Electric Co., a former subsidiary of National Grid now owned by PPL Electric Utilities under the name Rhode Island Energy.

Narragansett and New England Power, also a subsidiary of National Grid, determined the solar project would require significant upgrades to the distribution and transmission systems, including a new substation, costing about $18 million, with the costs ultimately passed down to Green Development.

FERC denied the bulk of Green Development's arguments opposed to this cost allocation in orders issued in *September 2021* and *February 2022*. The commission upheld its findings of both orders upon rehearing (*EL21-47* and *ER22-707*).

Green Development's petition to the D.C. Circuit, argued in March of this year, alleged FERC mischaracterized some of the company's arguments, failed to justify its jurisdiction over the upgrades, misinterpreted the definition of "direct assignment facilities" in the *ISO-NE* tariff and that the RTO and New England Power failed to file a new application for transmission service in accordance with the tariff.

In its ruling on Friday, the D.C. Circuit sided with FERC, rejecting all four of these clams.

"Each of Green Development's four grounds for vacatur lacks merit. Accordingly, we deny the petitions for review," wrote Circuit Judge Karen L. Henderson.

Green Development declined to comment on the ruling. ■

ISO-NE News

ISO-NE Projects Decrease in Gas, Increase in Coal and Oil for 2032

Projection Does not Model Generator Outages; Does Include Everett LNG Import Terminal

By Jon Lamson

ISO-NE projects an approximate 47% decline in gas generation for the year 2032 compared to current levels but expects coal and oil generation to increase by 45% to meet winter peak loads, the RTO told its Planning Advisory Committee on July 25.

Despite the expected winter increase in coal and oil generation, ISO-NE *anticipates* emissions declining across all months by 2032, with the largest emissions reductions coming in the spring, summer and fall. ISO-NE projects annual emissions being nearly half of 2021 levels, declining from about 30 million tons of carbon per year to 16 million tons.

These findings are part of the RTO's ongoing Economic Planning for the Clean Energy Transition pilot study. The study takes into account the increase in peak load due to electrification projected by ISO-NE's 2023 Capacity, Energy, Loads and Transmission report. (See *ISO-NE Increases Peak Load Forecasts*.)

"Additional PV and wind resources beyond what is already in the model may help alleviate demand for dispatchable generation, but the needed volume of energy is significant," said Benjamin Wilson of ISO-NE. "Some additional energy storage will likely be needed to shift the energy from when it is produced to when it will be needed."

Wilson said the results indicate overall lower production costs and locational marginal prices due to the influx of zero-marginal-cost energy resources replacing gas generation.

"The system may experience an increase in reliance on stored fuels (LNG, oil, and coal) in the winter despite the new wind, solar and energy storage resources," Wilson added.

The results contain limits: The study did not model generator outages and includes generators that did not receive capacity supply obligations in the latest Forward Capacity Auction and may retire prior to 2032. This includes the Merrimack Station, the last coal-fired generator in New England. The study also assumes continued operations of the Everett LNG import terminal for 2032.

"A reduced LNG capacity would lead to an increased demand on other stored fuel resources," Wilson said.

The Merrimack Station in New Hampshire, the last coal-fired power plant in New England | *SayCheeeeeese, CC0 1.0 Public Domain, via Wikipedia*

Transmission Planning

Also at the PAC, Dan Schwarting, manager of transmission planning at ISO-NE, presented initial high-level takeaways from the RTO's *2050 Transmission Study*, looking at meeting the transmission needs of the region for 2035, 2040 and 2050. ISO-NE expects a draft of the study to be ready to present to the PAC in November.

Schwarting told the committee early results indicate relatively small reductions in the projected 2050 winter peak load are associated with outsized reductions in transmission costs.

A 10% reduction of ISO-NE's initial 57-GW winter peak "snapshot" for 2050 — which *represents* the electrification of nearly all the region's heating using existing technology — would be associated with a roughly one-half to one-third reduction in transmission costs, Schwarting said.

Despite uncertainty in predicting future load concentrations and generator locations, Schwarting said some high-likelihood upgrades could be pursued in the near term, including increasing capability for north-south transfer and Boston imports.

"Investment in addressing these concerns may be prudent regardless of exact generator locations and load distribution," Schwarting said.

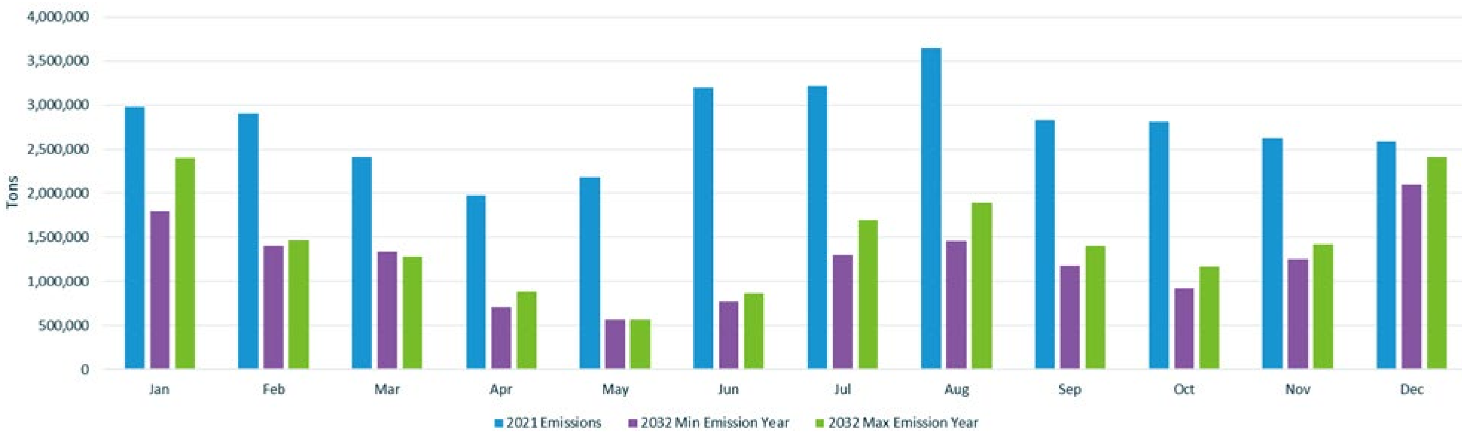
To meet the future needs for north-south transfers and Boston imports, Schwarting laid out four potential pathways: prioritizing rebuilds of existing lines, building new 345-kV overhead transmission, building new HVDC transmission lines or building an offshore grid that would enable power transfer between states and regions.

"In many parts of New England, addressing concerns by rebuilding existing lines for higher capacity is clearly more cost-effective and feasible," he said, adding that using this approach to address all regional needs could end up being more expensive than the alternatives, and this path could not scale up to meet a 57-GW peak demand.

Schwarting highlighted some potential benefits of an offshore grid, including the ability to move power between interconnection points when capacity is not taken up by wind power.

"For example: In summer daytime peak snapshots, wind is assumed to be at 5% output. The remaining 95% of cable capacity is available

ISO-NE News



Monthly emissions in 2021 compared to 2032 min and max scenarios | *ISO-NE*

to transfer power from one point of interconnection to another," Schwarting said. "Beyond what is modeled in the 2050 Transmission Study, these grids could be expanded to include wind farms connecting to New York, PJM or other neighboring areas."

Schwarting emphasized that providing a full cost/benefit analysis of an offshore grid is beyond the scope of the study, which will look only at approximate costs and a limited set of benefits.

"While significant research and development towards offshore transmission has been performed in Europe, meshed offshore HVDC systems are not yet in use commercially," Schwarting added, noting the National Renewable Energy Laboratory is conducting a two-year study into Atlantic offshore wind transmission that will consider the potential for an offshore grid.

Asset Condition Projects

Eversource, National Grid, and Avangrid presented on several asset condition projects totaling over $100 million:

- Eversource expects to spend about $31 million on structure replacements and optical ground wire installations on one 115-kV line and two 345-kV lines in Connecticut, citing age-related issues including woodpecker damage, cracking and splitting, and damaged insulators and deteriorated steel hardware. The expected in-service dates for the projects range from late 2024 to early 2025.
- National Grid proposed spending about $6 million to replace five 69-kV and six 115-kV Oil Circuit Breakers at the Northboro Road Substation in Northboro, Mass.
- Avangrid increased its cost estimate for its 115-kV Derby Junction to Ansonia Line Rebuild Project, proposing to spend $71 million to rebuild the line, nearly doubling the cost compared to its 2021 estimate of the rebuild. The company said the rebuild would extend the life of the line by at least 50 years. ■

MISO News

DTE Earnings Focus on Faster Clean Energy Transition

Michigan PSC Accepts DTE Plan to Reduce Carbon 85%

By Amanda Durish Cook

DTE Energy touted the recently approved settlement on its 20-year resource plan in its second-quarter earnings call Thursday.

The Michigan Public Service Commission on Wednesday accepted DTE Energy's negotiated integrated resource plan that accelerates renewable energy additions, hastens the closure of its last coal plant from 2035 to 2032 and sets a path for the utility to reduce carbon by 85% from 2005 levels within nine years. (See *DTE, Activists Announce Agreement to Exit Coal by 2032*.)

Meridian Wind Park | *DTE Energy*

"Our CleanVision integrated resource plan outlines our investment in Michigan's future, and we are grateful to the 21 organizations from across Michigan for their diligent work on this settlement agreement," DTE Energy CEO Jerry Norcia said in an earnings press release. "From ending the use of coal in 2032 to reducing future costs of our clean energy transformation by $2.5 billion, this plan is a road map to cleaner, more reliable and affordable energy for our customers."

Speaking during an earnings teleconference, Norcia said DTE conducted analyses and outreach to come up with a "balanced and diversified" approach to the future energy mix. He said over the next decade, DTE Energy will invest more than $11 billion in the clean energy transition. He also said by 2042, the utility will add 15 GW of renewable energy and nearly 2 GW of energy storage.

Norcia said the IRP settlement demonstrates the "constructive nature" of the regulatory environment in Michigan.

DTE Energy reported $206 million ($0.99/share) of earnings in the second quarter. That compares to the $171 million ($0.88/share) DTE earned for the same period in 2022.

DTE Energy said it invested $1.5 billion over the first half of the year on electric reliability improvements and cleaner energy generation. Norcia noted that during the quarter, it placed Michigan's largest wind park — the 225-MW Meridian Wind Park — into service. ■

NYISO News

NYISO Addresses NYC Near-term Reliability Need

ISO to Solicit Potential Solutions, Shares Update on NYC PPTN

By John Norris

ALBANY, N.Y. — NYISO took stakeholder questions on its *statement* about the predicted reliability shortfall in New York City, during the Electric System Planning Working Group meeting on July 25.

"The short-term reliability need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the peaker rule," read the ISO's statement.

NYISO Reliability Studies Manager Keith Burrell explained the ISO was required by *tariff* section 38.3.6 to explain why it was soliciting "a regulated non-generation short-term reliability solution solely from a responsible transmission owner," which became necessary after its second quarter short-term assessment of reliably report identified that NYC could have up to a 446-MW marginal reliability deficiency by 2025. (See *NYC to Fall 446 MW Short for 2025, NYISO Reports*.)

"The reason the need observed in our Q2 STAR wasn't observed in prior STAR reports was primarily due to the updated demand forecast," said Burrell, referring to how planned fossil fuel plant retirements were included for the first time.

"We identified in our 2022 RNA [reliability needs assessment] that if demand forecast increased by as little as 60 MW there was the potential for a reliability need," he added, "looking now at NYC forecasts, the demand went up by 294 MW when considering the baseline statewide coincident peak for estimated needs."

Howard Fromer, who represents Bayonne Energy Center, asked if NYISO was measuring the need in megawatts or megawatt-hours.

Burrell responded, "It's a little bit of both: When we identify a need, it's going to get the megawatt deficiency, but we also do some investigation to get an idea of what the hour of the need can be."

Fromer then asked whether NYISO would entertain solutions that were less than the 446 MW of identified need, and if some combination of regulated solutions would be considered.

"Ultimately, the solutions selected need to fully address the need but can come from multiple different options," Burrell said. NYISO staff referred to section 38.6.1 of the *tariff* to clarify what constitutes a viable and sufficient solution.

Mark Younger, president of Hudson Energy Economics, asked NYISO to further investigate statewide reliability shortfall scenarios, pointing out that the Q2 STAR also identified that at extreme loads the entire state could see marginal deficiencies. "It would be good to have some of these [scenarios] chased down before we finalize the next round of analysis," he said.

Doreen Saia, an attorney with Greenberg Traurig, warned NYISO that whatever solution it chooses, "there are certain actions that can't be undone," referring to how decisions to decommission Indian Point nuclear power plant, in hindsight, seem regrettable given the state's current reliability needs.

NYISO plans to post the third quarter STAR by Oct. 13.

NYC PPTN

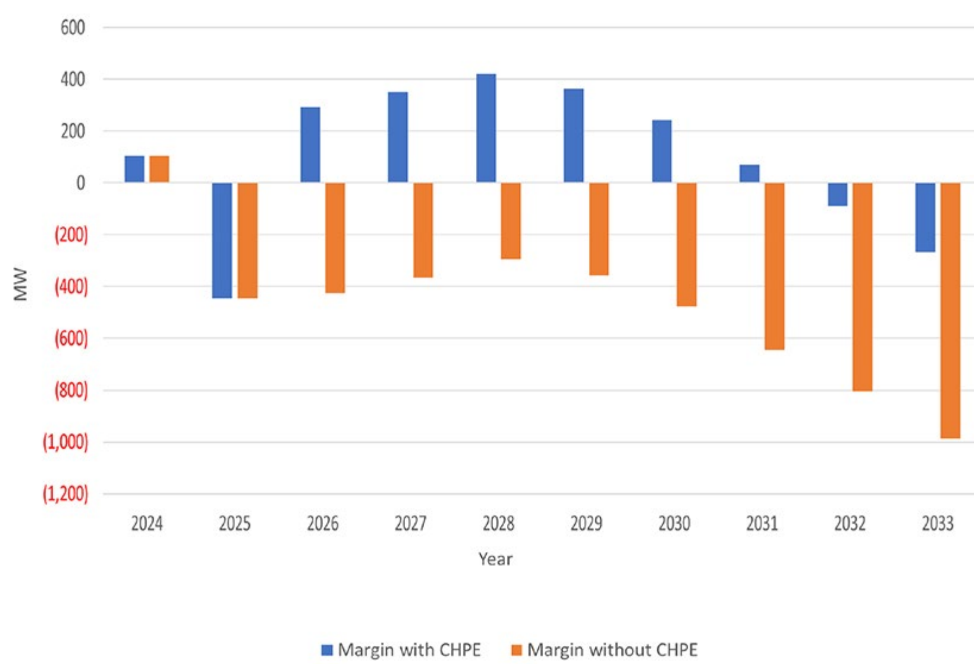
NYISO also gave a status *update* to the ESPWG/TPAS on the public policy transmission need for New York City, which was called by the state's Public Service Commission to deliver at least 4,770 MW of offshore wind from Long Island. (*22-E-0633*).

The PSC ordered another Zone J-to-K OSW transmission solution to help meet state energy goals like producing 9,000 MW of OSW by 2035, using the momentum that was built after NYISO's board selected a project to fulfill the Long Island PPTN that called for at least 3,000 MW of export capability. (See *New York PSC Calls for More Transmission for Long Island OSW*.)

NYISO has begun conducting baseline assessments for the New York PPTN to determine the actual need and what solutions are needed to meet that need. This process is followed by a 60-day window where developers can propose their own transmission solutions.

NYISO tentatively will start soliciting solutions in the first quarter of next year with the goal of the PPTN being completed by the third quarter of 2025.

NYISO promised it was actively coordinating with state agencies and other relevant parties, such as the Department of Public Service, Con Edison and the New York State Energy Research and Development Authority, in response to questions from stakeholders about the ISO's engagement with these groups. ■



NYC Transmission Security Margins | *NYISO*

NYISO News

NYPA Taking to the Skies with Expanded Drone Fleet

By John Cropley

The New York Power Authority is going all-in on drones, launching a $37.2 million program to expand their use for inspections as a safety, efficiency and economy measure.

NYPA's Board of Trustees on Thursday approved an initial $9.6 million allocation to launch the five-year Unmanned Aerial System program.

Drones have been gaining favor for years as a tool to inspect transmission lines. It is much slower to have a line person climb up for a visual check and much more expensive to fly over in a helicopter. And with both of those options, the implications of an accident are much worse.

Even a substation inspection is safer with a drone, as it does not put anyone close to high voltage.

The nation's largest state-owned utility operates 1,400 circuit-miles of transmission lines. But it also has bridges, dams, waterways, fossil fuel generating stations and conventional and pumped hydropower facilities to monitor and maintain.

NYPA's drones are equipped with high-resolution cameras and sensors that can detect flaws not visible to the human eye. The authority plans to make as much use of them as it can.

"By bringing more drones into our day-to-day operations, we can better harness the benefit of automation, safety and consistency across our assets while reducing costs and insuring a more reliable power supply," NYPA Robotics Program Manager Peter Kalaitzidis said in a *news release*. "Inspections can be improved and expanded to include other areas and assets. With use of drone technology, we can more easily capture the real-world state of our operations to support real-time decision-making."

NYPA has trained nearly 100 pilots and has been getting its drones out to its operating units to allow them to figure out their own best uses for the technology.

The goal now is to buy more hardware and software; expand and improve training; standardize policies and procedures; and develop a platform from which to gather and make the best use of data recorded on each flight.

The authority is keeping its regulatory compliance up to date as well. Earlier this year it received its first waiver from the Federal Aviation Administration to operate drones beyond the pilot's line of sight. NYPA said this will be useful at its Blenheim-Gilboa Pumped Storage Power Project, which sprawls more than 2 miles across very rugged terrain. ■

New York Power Authority personnel use drones to inspect utility infrastructure. | *NYPA*

NYISO News

NYISO Management Committee Briefs

The NYISO Management Committee on Wednesday *voted* for the ISO to not conduct a new cost-of-service *study* to modify the Rate Schedule 1 cost allocations between units withdrawing and injecting.

The divided vote was previewed in June when NYISO announced stakeholders would have the opportunity to potentially change RS1 allocations, which have been set at 72% for withdrawals and 28% for injections since 2011. (See "Vote Set on Rate Schedule 1," *NYISO Management Committee Briefs: June 13, 2023*.)

Some stakeholders opposed the motion and voted in favor of conducting the study, arguing that the allocations had not been updated in a long time and keeping things up to date was important because new technologies are entering the grid.

David Clarke, director of wholesale market policy at LIPA, argued in favor of conducting the study, saying, "we have put this off for a long time. … It is probably important to do this at least once a decade."

On the other hand, Scott Leuthauser of Hydro-Quebec Energy Services argued against the study, saying, "it seems to me that nobody's really opposed to the current values."

"We have so many really high-priority projects that we're not doing because resources are not available, so let's just keep it for another year," he added.

Howard Fromer, who represents Bayonne Energy Center, asked how distributed energy resources aggregations fit into these RS1 mechanisms.

Chris Russell, senior manager at NYISO, responded: "DER aggregations will be charged as a generator essentially," adding, "these resources would be charged the injection rate similar to how we charge special resources cases today."

Russell also said storage resources in an aggregation would be charged the prevailing injection rate whether it was injecting or withdrawing.

Erin Hogan of the state's Utility Intervention Unit argued that these resource-related issues highlight the need to update the RS1 cost allocations.

The motion passed with 91.22% of the vote in favor of not conducting the RS1 study.

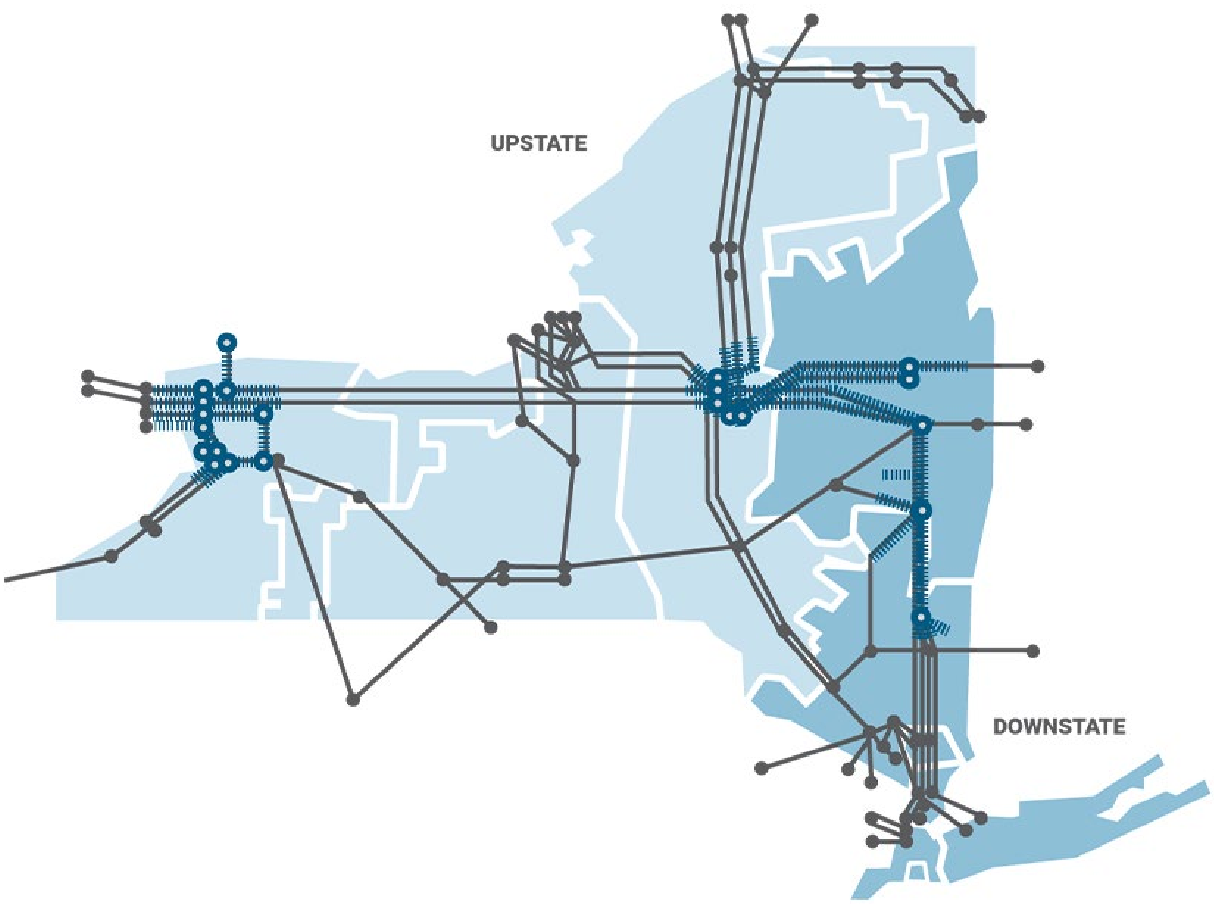
Board Selection Subcommittee

NYISO CEO Rich Dewey announced the ISO is forming a new board selection subcommittee to seek a replacement for Director Ave M. Bie, whose term ends in April.

Dewey said Julia Popova, chair of the MC and NRG Energy's manager of regulatory affairs, will lead the subcommittee.

Bie is a former chair of the Wisconsin Public Service Commission and joined NYISO's board in April 2009. ■

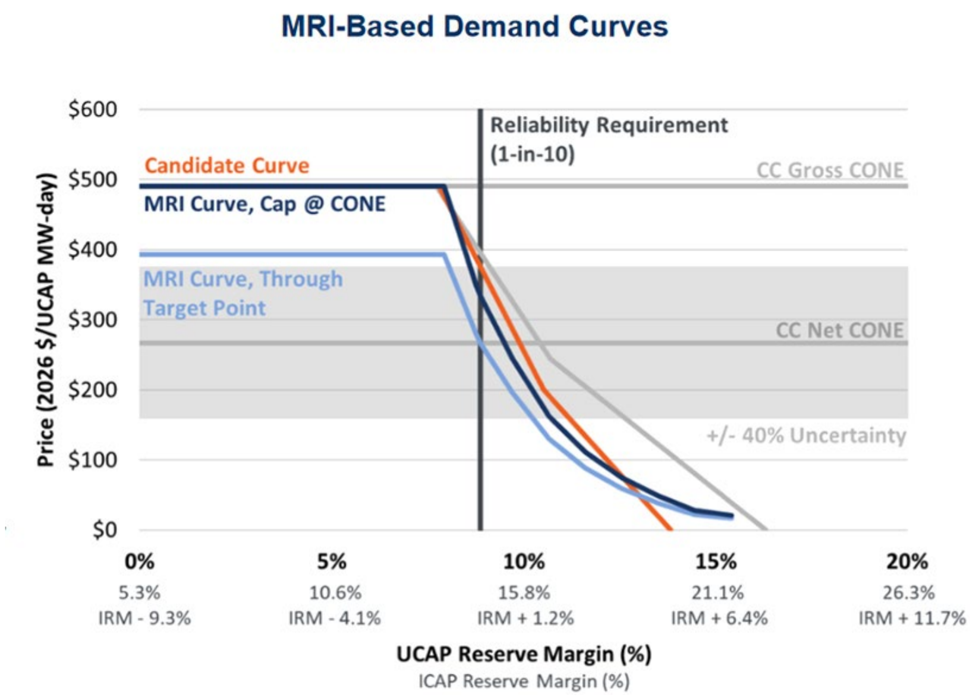
— John Norris



New York's points of interconnection | *NYISO*

PJM Updates Proposal as CIFP Nears End

By Devin Leith-Yessian



A PJM graphic shows variants of the marginal reliability impact (MRI) demand curves it proposed to use in its seasonal capacity auction design. | *PJM*

PJM *presented* several changes to its Critical Issue Fast Path (CIFP) proposal during the process' July 27 meeting, reworking portions related to the seasonal market, weatherization, site visits, performance assessments and market power mitigation.

Getting through a portion of PJM's 79-slide presentation spanned the entirety of the meeting, postponing presentations from *Constellation Energy* and the *Independent Market Monitor* to the next CIFP meeting today. Additional sections of PJM's presentation pertaining to reliability risk modeling and accreditation were moved to today's meeting, which is set to include presentations from Vistra, Buckeye Power and Leeward Renewable Energy. (See *PJM Updates Risk Analysis; Stakeholders Present Revised CIFP Proposals*.)

Following today's meeting, only one Stage 3 meeting remains on the calendar, set for Aug. 7. The following week will be saturated with standing committee meetings, with Aug. 13 being the final day for agenda items and documents to be added to the materials for the Stage 4 meeting on Aug. 23. In that meeting, stakeholders will present to the PJM Board of Managers and subsequent Members Committee meeting, which will include the vote to recommend a package to the board.

The Stage 4 meeting will begin with a detailed presentation of PJM's proposal, after which only members and invited non-member stakeholders will be allowed to continue participating. A sign-up form will be emailed to stakeholders subscribed to the CIFP and MC mailing lists.

Seasonal Auction Design Shifts to MRI Curves Over VRR

PJM Vice President of Market Design Adam Keech said the new seasonal design stemmed from stakeholder concerns that PJM's proposal was overly complex and not transparent. The previous iteration would have created variable resource requirement (VRR) curves for each season and aligned the price with the point on the annual VRR curve corresponding to the amount of cleared capacity. (See *PJM Adds Seasonal Capacity to Stage 3 of CIFP Proposal*.)

Thursday's proposal instead would use marginal reliability impact (MRI) curves for the seasonal auctions, which would be set in advance and with no adjustments made during the auction clearing. The shape of the MRI curves generally would align with the status quo VRR slope, but the "amplitude" of the curve would be increased to ensure resources could retain the annual costs of taking on a capacity commitment in a single season in the event the other season cleared at zero.

The MRI curve for each season would be calibrated so that if the amount of capacity procured was at or lower than the reliability requirement, the corresponding price would be at least the annual net cost of new entry (CONE) for the reference resource.

PJM Director of Economics Walter Graf compared the current approach to how locational deliverability areas (LDAs) have their own VRR curves designed to ensure that the reference resource can meet its reliability requirement assuming the rest of the RTO cleared at $0 and no outside revenues would be available for resources within the LDA.

Several stakeholders expressed concern that increasing the amplitude of the curve would amount to doubling the cost consumers pay for capacity and requested PJM present more analysis on the expected reliability and cost impacts of the proposed approach.

Economist James Wilson, a consultant for state consumer advocates, gave the example of grafting PJM's proposal onto a monthly capacity market and questioned if that would result in the possibility of a month with capacity prices increased by a factor of 12.

Graf said he believes it makes sense that the reference resource would be able to meet its annual costs in one month, under Wilson's example, if that period is determined to hold the entirety of the grid's reliability risk. He added that PJM's model wouldn't increase both the price and the quantity.

"The price in a given season is higher only if the reliability risk is higher and the quantity procured is lower," he said.

Market Power Mitigation Changes to Must-offer for Intermittents, CPQR

The changes to PJM's proposal also include removing the must-offer requirement for intermittent resources. Several resource types, including solar, wind and storage, are not subject to the requirement that generators must offer into the capacity market, an exception that PJM had proposed removing in earlier versions of its package. (See *PJM Completes CIFP Presentation; Stakeholders Present Alternatives*.)

PJM's Skyler Marzewski said retaining the

PJM News

exception stems from intermittents not possessing a way of physically hedging against the risk that an emergency may occur at a time when they are not able to be online, subjecting them to capacity performance (CP) penalties. He said PJM has not determined if it intends for demand response to be subject to the requirement.

Graf said any resource that would not be required to submit an offer but intends to do so would need to notify PJM sufficiently in advance of the reliability analysis being conducted for that auction.

Emma Nix of Leeward said retaining the must-offer exception likely would lead to Leeward and a coalition of renewable developers dropping plans to offer an alternative to PJM's proposal. "This is a giant step forward for getting renewable support for PJM's proposal," she said.

While the must-offer exceptions were one of the major concerns renewable developers had with the PJM package, Nix said they support requiring intermittents to participate in the capacity market in the long term, so long as the requirement is accompanied by a way of mitigating risk of performance penalties during times those resources can't be expected to operate.

PJM added detail to its default capacity performance quantified risk (CPQR) calculation, in which it would create a default risk value for each resource class with an option for generation owners to continue to submit unit-specific values instead.

Graf said PJM would look at the 95th percentile of events to estimate a unit-specific analysis of how resources may over- or underperform during modeled performance assessment intervals (PAIs).

The amount of risk determined to be present at the 95th percentile would be multiplied by a cost-of-risk parameter, which in his demonstration Thursday was set at 10%. The cost-of-risk and other parameters in the calculation would be reviewed periodically.

Calpine's David "Scarp" Scarpignato questioned why the result shouldn't be the risk at the 95th percentile. Graf said competitive market sellers would be willing to have a small downside as a potential outcome at less than the full amount they stand to gain.

Rework to Performance Assessment Testing

PJM's proposal to require a physical demonstration that resources can meet their capacity commitments, with penalties for any shortfalls during testing, was revised to measure generators against their daily committed ICAP, rather than against their average seasonal committed ICAP. PJM's Pat Bruno said the change was made with the understanding that a resource's capability can change throughout a season.

The test would be based on either operational data for the relevant season provided by the generator or a demonstration that the resource schedules with PJM.

PJM also would be able to initiate two operational tests by scheduling a unit, following its parameter limits and considering the test a success if it is able to come online within a certain amount of its expected time and operates for its minimum run time. Generators would be made whole for costs incurred during testing.

Bruno said tests would be conducted at times that mirror reliability risk, such as cold weather during the winter.

A failed test would result in a forced outage ticket and the unit would be marked unavailable until it indicates to PJM that the issue behind the failure is resolved, or it successfully starts back up. PJM would be able to schedule re-tests, which would result in a capacity deficiency penalty if failed. Re-tests following a failure also would not be eligible for make-whole payments.

Bruno said the deficiency penalties are designed to be imposed following a failed re-test out of a desire to not assess large penalties against a generator for a random mechanical failure and to focus instead on repeated inability to come online.

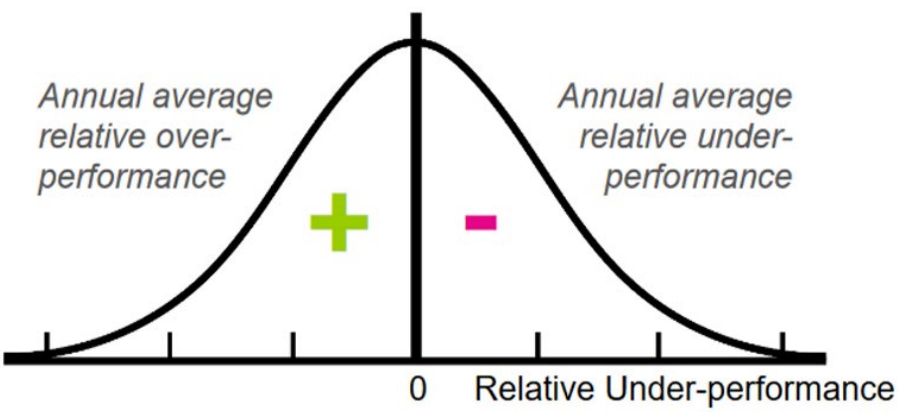
Vistra's Erik Heinle asked if resources would have enough time to nominate for fuel prior to a test. Bruno responded they would respect the notification times in a generator's parameters.

Site Visitation Details

PJM gave more detail on plans to include site visits in its CIFP proposal with the goal of ensuring preparations for extreme conditions are being undertaken and to gather information on any challenges. The current thinking is to have every capacity resource visited around every five years, with a focus on newer generators.

The visits would look to ensure compliance with weatherization requirements and to evaluate if fuel arrangements are being made.

Owners would be given advance notice of any visits and any issues identified would have a "cure period" established with generator input in which no penalties would be imposed. Failure to address issues long-term could result in penalties. ■



$$CPQR_{Seasonal} = Risk\ Cost \times Extreme\ Value$$

Mean ($/MW-d)	Extreme Value (%ile)	Extreme Value ($/MW-d)	Cost of Risk (%)	CPQR ($/MW-d)
$0 *default*	95th *default*	$150 *unit-specific (example)*	10% *default*	$15 *unit-specific (example)*

PJM detailed its proposed default Capacity Performance quantified risk calculation during the July 27 CIFP meeting. | *PJM*

PJM News

PJM MRC/MC Briefs

Stakeholders Endorse Manual Revisions Conforming to New FERC Requirements

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee endorsed *revisions* of Manual 14B to align with new language in NERC's TPL-001-5.1 standard during its July 26 meeting. The changes aim to establish new transmission system performance requirements. (See "Stakeholders Endorse Quick Fix Manual Revisions to Conform to NERC Standards," *PJM PC/TEAC Briefs: July 11, 2023*.)

The new language increases the requirements for PJM's spare equipment standards, creates a new threshold for new outages to be included in the planning horizon and expands the technologies considered part of a component protection system.

The previous NERC standard required that RTOs include outages longer than six months in their planning horizon, which was changed to leave the rationale up to the organizations. PJM proposed looking at upgrades to 230-kV or higher rated equipment or outages that would last longer than five days.

The proposed spare equipment standard would involve PJM reaching out to asset owners to inquire about their policies for maintaining spare equipment to replace any failures that could take a year or two to replace. If those owners don't maintain an inventory, PJM would conduct a study to evaluate the impact of that equipment failing.

The changes were brought before the July Planning Committee meeting as a quick fix proposal, which allows for a *problem statement*, *issue charge* and solution to be brought concurrently and voted on in the same meeting. The manual changes were effective immediately following MRC endorsement.

PJM and Monitor Present Generation Deactivation Issue Charge

PJM's Paul McGlynn gave a first read of a *problem statement* and *issue charge* being drafted in collaboration with the Independent Market Monitor that would investigate increasing the deadline for generators to notify PJM of plans to deactivate, the compensation for generation owners that agree to continue operating facilities beyond the desired deactivation and the triggers offering a generator a reliability-must-run (RMR) contract.

Possible changes to capacity market rules and cost allocation for RMR contracts are out-of-

Stu Bresler, PJM | © *RTO Insider LLC*

scope in the issue charge. McGlynn said a new senior task force reporting to the MRC is the envisioned route for engaging in the discussion given the number of areas that deactivations impact, including planning, markets and operations.

The only reason PJM currently can provide for seeking an RMR is transmission reliability criteria, but McGlynn said there may be other reasons it wishes to keep a generator operating. The primary rationale the RTO envisions is losing reliability parameters such as black start when a generator goes offline.

Monitor Joe Bowring said the current rules create a lot of confusion and uncertainty, which results in resources being wasted on proceedings. "The rules need to be clarified," he said.

Vistra's Erik Heinle questioned if there would be a limiting principal in how long an RMR contract could run for, adding that it could take a long time to replace the black start service provided by a given generator while also discouraging other resources interested in investing to provide that service.

"Before we go down this route, we need to be careful to think of where we may end up," he said. "We need to be careful of what signals we're sending to the market."

McGlynn said PJM's goal is to keep RMR contracts as limited in use and duration as possible.

"Nobody wins when there's an RMR. In general, the generators — they've already made the decision to deactivate, they want to deactivate it," he said.

Bowring said he's concerned about broadening the scope of RMR and believes it should be as narrow as possible but is willing to discuss options.

Dominion's Jim Davis questioned if part of the rationale for re-evaluating how RMR contracts function is to slow the pace of retirements or make it take longer for them to exit the market. He said the company would not support any changes that could hinder generators' ability to retire and that one of the purposes of a functional capacity market is to send price signals, including for retirement.

"Ultimately, the decision to retire a resource belongs to the resource owner and that decision is partially made to redirect capital," he said.

McGlynn said the intent is to look at the process after the decision to retire has been made and support that determination. Senior Vice President of Market Services Stu Bresler added that the longer notice period for deactivation requests is meant to ensure the grid is prepared for resources to go offline.

Susan Bruce, of the PJM Industrial Customers Coalition, said it's important RMR doesn't become more attractive than market participation for some resources. She supported discussion of additional triggers for opening an RMR contract and said it also may be prudent to make capacity market changes in scope, given the large changes being considered in the Critical Issue Fast Path (CIFP) process and elsewhere.

Stakeholders also questioned if the voluntary nature of RMR contracts would be in scope, to which McGlynn said his understanding is that PJM can't force generators to continue operating. Bresler said the issue charge doesn't explicitly preclude having that discussion but that it may be a question for FERC to decide if PJM has the authority.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said he believes not explicitly ruling out discussion of permitting RMR contracts to maintain resource adequacy is "extremely dangerous" and should be out of scope. The capacity market has its own backstop and RMR should be focused on transmission needs, he said.

Several stakeholders also questioned if the complexity of the topic may not lend itself to the "CBIR Lite" (Consensus Based Issue Resolution) process.

PJM News

PJM Seeks Stakeholder Process on Reserve Certainty

PJM's Donnie Bielak presented a wide-spanning *issue charge* and *problem statement* on reserve certainty, with several immediate, medium-term and long-term goals for stakeholders to consider in a proposed new senior task force. PJM has seen a decline in the response rate for reserve deployments since the two tiers of reserves were consolidated in a reserve market overhaul implemented Oct. 1. That resulted in PJM increasing the synchronized reserve requirement by 30% this year, overriding stakeholder objections. Bielak said it's likely nobody was happy with that outcome, and the goal of the new issue charge is to find better permanent solutions. (See "Stakeholders Reject PJM Synch Reserve Manual Change; RTO Overrides," *PJM MRC/MC Briefs: May 31, 2023*.)

The seven key work activities include reserve performance and penalties, aligning the offer structure with fuel procurement, how resources are deployed and PJM's target reserve procurement. The proposed timeline for immediate need topics, such as performance and penalties, is to have a solution within a year, while the long-term need to incentivize resource flexibility to match grid needs is set for three to five years.

Heinle said he's concerned such a wide range of topics could lead to the task force becoming directionless, a fate he said befell the resource adequacy senior task force before it was converted to the CIFP process with a tight turnaround mandated by the Board of Managers. He suggested that finding ways of keeping the work focused on specific areas would help prevent the process from outrunning stakeholders' best intentions.

Sotkiewicz said he believes more education on the impact of the reserve market changes implemented in October is needed and that the lower response rate could stem from a software or design issue in the new system. He said prices are decreasing leading up to a spin event, which is the opposite of what should be happening. He said PJM rhetoric about generators underperforming and the possibility of enforcement actions has been unhelpful.

"I think there's something actually much more systemic here that requires more investigation and education ... for members to understand that," he said.

Bruce said more analysis is needed to understand the dynamics of how the increasing number of inverter-based resources on the grid impacts reserves and what their contribution looks like. More education also is necessary to understand what is driving the lower performance. She said she worries if that is not established, it could lead to consumers spending more money on reserves to shore up the issue.

"The solution cannot be let's just have customers pay more for reserves. Because if we don't understand what the problem is ... that's just throwing money at the problem," she said.

Bowring said the issue charge is too broad and should be broken into smaller stakeholder processes. He said he believes synchronized reserves' failure to respond in recent months has to do with communications and training.

First Read on Peak Market Activity Credit Activity Proposal Expected in August

The Risk Management Committee (RMC) has finalized a slate of packages it plans to vote on during its August meeting, which will be followed by a first read at the MRC during its Aug. 24 meeting. Thomas Zadlo, RMC chair, said PJM is exploring ways of expediting a vote at the RMC to either hold a same-day vote in August following the first read or use other accelerated stakeholder actions to allow the proposal to be implemented in time for winter.

Constellation's Adrien Ford said the company supports any acceleration that can be found while still respecting the need for appropriate document review.

Proposed changes include introducing minimum exposure and minimum transfer amounts, setting maximum amounts that can be invoiced over given timeframes and changing how collateral shortfalls and surpluses are calculated.

Other MRC Discussions:

- Several state consumer advocates objected to or abstained from endorsing *revisions* to Manual 13 stemming from its periodic review, which Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said was due to dissatisfaction that the review of the manual did not take into account how emergency notifications and public messaging performed during the December 2022 winter storm. The changes were approved by acclamation as part of the consent agenda.

- PJM presented a first read of proposed *revisions* to Manual 13 to include essential actions in NERC's cold weather preparations for extreme events. Changes focus on the amount of detail needed in member load-shed plans.

Members Committee Endorses IROL-CIP Cost Recovery

The Members Committee voted to endorse a PJM-sponsored *proposal* to create a cost-recovery mechanism to allow generators to recoup expenses incurred by making upgrades after being designated critical to the derivation of an interconnected reliability operating limit (IROL) under NERC's critical infrastructure protection (CIP) standards. The acclamation vote had six objections and 11 abstentions. (See "MRC Endorses IROL-CIP Cost Recovery," *PJM MRC/MC Briefs: June 22, 2023*.)

PJM's Darrell Frogg, who presented to the MC Wednesday, has compared the cost-of-service payment structure in the proposal to the cost-recovery structure for black start service, with generators submitting their costs to the RTO and Monitor to review and costs allocated to market participants.

The proposal was opposed by the Monitor, who presented a competing proposal in the Operating Committee, on the grounds the costs should be included in generators' market offers and it could become a slippery slope to new non-market cost-of-service structures for other services, a concern he returned to Wednesday. He argued there is no explanation for what differentiates IROL-CIP-related costs from other services generators include in their offers.

Bruce said some industrial customers abstained from the vote over concerns the process PJM uses to select IROL-CIP facilities may lead to increased costs if PJM designates one generator, it makes the requisite upgrades and then PJM shifts the designation to a different resource. She said the "heartache" isn't with having to pay for reliability upgrades, but rather with cost minimization.

Poulos said some advocates who abstained from the MRC vote switched to being in opposition because of a concern the proposal turns away from using markets and toward a less transparent cost-of-service approach.

PJM Assistant General Counsel Thomas DeVita said he believes the proposal included a healthy balance between allowing generators to recover costs while protecting consumers. He said costs incurred before the critical designation or those that would have been made regardless can't be included and the proposal also includes provisions to avoid double counting.

"We have some very significant and serious protections built in for customers," he said. ■

SPP News

SPP Board Rejects Recommended Competitive Transmission Project

Directors at Odds over Proposal's Costs

By Tom Kleckner

ST. PAUL, Minn. — SPP's Board of Directors last week rejected an industry panel's recommendation to award a competitive project in New Mexico, leaving staff unsure of the next steps.

"This is a first for us. We probably need a little bit of guidance," SPP CEO Barbara Sugg said.

Pointing in General Counsel Paul Suskie's direction, she asked her governance "guru" for guidance.

Suskie said SPP's tariff does not "contemplate" remanding the project's evaluation back to the five-person industry expert panel (IEP) responsible for awarding projects under the RTO's competitive selection process. According to the tariff, the board could select either the recommended or alternate proposal, based primarily on the information provided by the panel, he said.

The IEP "put so much time and energy into this, I think it would be very difficult for them to come back with a different answer," Sugg said.

"My advice to you, if you turn down our recommendation, is there's only one other recommendation that could come up for your vote," said Mike Jacobs, the panel's chair and president of consulting firm Both Supply & Demand. He said if the board directed the IEP to run further projections and scenarios, "we'll report back to you, but the analysis could lead to paralysis."

The directors debated their options before deciding to take up the issue during their normal post-meeting debrief.

SPP said Wednesday that the board is working to determine "the best course of action to reach a timely outcome that preserves the integrity" of its FERC-approved Order 1000 process.

"SPP will communicate their plans to stakeholders in the coming days," spokesman Derek Wingfield said.

The IEP was seated last August to evaluate anonymous bids to build a 345-kV double-circuit line in eastern New Mexico from Crossroads through Hobbs to Roadrunner in two segments totaling 143 miles. The upgrade, estimated to cost $376.3 million, was proposed by Xcel Energy subsidiary Southwestern Public

IEP Chair Mike Jacobs (left) explains the panel's recommendation as William Steele, Mike Schiavone listen. | © RTO Insider LLC

Service (SPS) as an alternative to a previously identified project in the 2021 Integrated Transmission Plan. (See *SPP Board of Directors/ Members Committee Briefs: July 26, 2022*.)

The panel received only three bids for the project, two of them from the same entity. Following the process, it unanimously recommended Proposal B, which accumulated the most points in the scoring system with 1,023.38 out of a possible 1,100. Proposal B also had the high scores in three of the five categories and placed second in another.

The IEP said the winning proposal presented "the best evidence that it can produce a successful project, built within budget; would operate as intended and in accordance with the requirements set out by SPP; and would be constructed in a safe manner."

Proposal B also had the highest estimated construction cost at $291.6 million. Proposal C, which had a submitted cost of $220 million but finished third in the scoring, was selected as the alternate.

The proposal only gathered three "for" votes during the Members Committee's advisory vote. Twelve members abstained, and seven voted against it. Ironically, one of those voting "no" was SPS, the incumbent transmission owner and widely believed to be one of the two bidders along with NextEra Energy. (The Florida-based transmission developer does not have a vote on the committee.)

"We do have an indication from the members that the motion shouldn't pass. We didn't get specific guidance on members about why they voted 'no,'" Director John Cupparo said. "We're in a bit of a conundrum. How do we extricate ourselves from this situation?"

Jacobs, who has participated on three of SPP's five IEP panels and chaired two of them, was unable to satisfactorily answer Director Larry Altenbaumer's questions attempting to understand why the more expensive option was recommended.

"I'm not sure the IEP's recommendation is necessarily the wrong one," Cupparo said. "What I'm really looking for is more supportive analysis that tells me the risk is too great for a lower-cost alternative. I don't know if that's the case or not, but the pieces seem to be there. I don't know if that's something that can be turned around quickly or evaluated, but that would certainly be helpful." ■

SPP News

SPP Planning Response After FERC Rejection

Commission Overturned Decision on Cost-allocation Proposal

By Tom Kleckner

ST. PAUL, Minn. — SPP legal staff said last week it is evaluating whether to modify and refile a tariff revision to allocate "byway" transmission projects on a case-by-case basis or to seek a rehearing of the order.

Paul Suskie, SPP | © RTO Insider LLC

General Counsel Paul Suskie told the grid operator's Regional State Committee July 24 that staff is reviewing its options following FERC's rejection of its proposed methodology. (See *FERC Reverses Course on SPP Byway Cost Plan*.)

"We will do that in our ordinary course," Suskie told the committee, composed of SPP's state regulators. "From a timing perspective, we could probably get a result back from FERC and an approval rather than going through the appeal process."

Asked whether SPP could work the two paths in parallel, Suskie warned the RSC that doing both at the same time would create *ex parte* limits when communicating with FERC.

In a July 13 order, FERC unanimously reversed a 2022 decision approving the RTO's process to allocate byway transmission projects — facilities rated at 100 to 300 kV — after rehearing arguments raised by several SPP members. The commission rejected SPP's proposed methodology without prejudice and dismissed a November compliance filing as moot (*ER22-1846*).

FERC said SPP failed to prove its proposal to regionally allocate 100% of a byway facility's costs on a postage-stamp basis would result in outcomes that are just and reasonable and not unduly discriminatory or preferential.

The grid operator currently allocates one-third of byway projects' cost to the RTO footprint, with customers in the transmission pricing zone where the project is built being allocated the rest. "Highway" projects — those larger than 300 kV — are allocated RTO-wide.

RSC and its Cost Allocation Working Group have been working on the issue since 2017. It was one of 21 initiatives developed by the Holistic Integrated Tariff Team before the COVID-19 pandemic. Stakeholders and staff have produced reports and white papers that led to an earlier tariff revision being rejected by FERC in 2021.

"It's probably an understatement to say I'm disappointed to see the FERC action," said RSC President Andrew French, with the Kansas Corporation Commission. "I do think we have an opportunity here to see if maybe there's a better approach, maybe even an approach that could address some of the concerns in our stakeholder process and hopefully we come up with something better. This is something that we have developed an extensive record on."

KCC Commissioner Andrew French (left) and Texas PUC Commissioner Will McAdams guide the Regional State Commission's discussion. | © RTO Insider LLC

Dana Shelton, legal counsel to the Louisiana Public Service Commission, pointed out that the agency, along with those of New Mexico, Oklahoma and Texas, opposed the revision request when it came before the CAWG in December 2021. FERC Commissioner Mark Christie noted the lack of "uniform" state support for the proposal in a concurrence to the order.

"It was on what we view as illegitimate cost-allocation principle ... and an unjust and unreasonable rate allocation," Shelton said. "We do continue to have concerns along those lines. I would ask that SPP and all concerned keep that in mind."

"It was an issue of cost allocation and equitable treatment for utilities," Texas Commissioner Will McAdams said. "Texas shared those concerns and would stand on that position."

McAdams Elected RSC's Vice President

RSC members elected McAdams as their vice president. He replaces Geri Huser, who stepped down from the Iowa Utilities Board in May, four years short of her term's expiration.

Minnesota's John Tuma was elected to replace McAdams as the committee's secretary and treasurer.

SPP CEO Barbara Sugg recognized McAdams during her president's report to the board for his "exceptional leadership" of the stakeholder group addressing the RTO's resource adequacy issues. (See *SPP REAL Team Endorses Winter Resource Requirement*.)

"I have heard nothing but accolades for your leadership," she said. "I'm just so impressed with the joint nature of that group and the value that they are going to bring to the RSC, to the board, to the Members Committee, really to all SPP stakeholders."

The RSC also approved South Dakota's Kristie Fiegen to chair the nomination committee that will select officers for 2024. Arkansas' Justin Tate and Oklahoma's Todd Hiett will serve with Fiegen. ■

SPP News

SPP Board/Members Committee Briefs

Board, Regulators Approve Long-awaited Congestion-hedging Package

ST. PAUL, Minn. — SPP's Board of Directors and its state regulators last week endorsed congestion-hedging improvements that have been years in the making, accepting staff's recommendation to approve a package of eight proposals designed to increase equity, fairness and financial transmission rights awards among market participants.

Three of the proposals are meant to improve equity by modifying: the long-term congestion rights (LTCRs) second round's nomination capacity from 100% to an incremental percentage up to 100%; the nomination capacity calculation for the first round of the annual auction revenue rights (ARRs) to better allocation ARRs; and the ARR's first round nomination capacity from 50% to an incremental percentage up to 50%.

Three other proposals will update load modeling and generator modeling to better align with transmission service studied and coordinate with transmission planning to review firm transmission assumptions used in the planning process. A seventh sets up stakeholder education to explain how existing tools can increase awards.

The distribution of excess auction revenue proved to be the sticking point before staff and the Regional State Commission's Cost Allocation Working Group (CAWG), comprised of regulatory staff, agreed on a phased-in approach that provides equity in congestion rent for firm rights to transmission paths.

Recommendation No. 5, owing to its place on the list, will distribute excess ARR awards using a nomination cap-minus award method that considers only LTCRs and annual ARRs from the first two auction rounds and monthly ARRs from the first iteration. The first year will use 50% of the current distribution method and 50% of the new method, with the latter accounting for all distributions going forward.

The methodology, proposed by Evergy, does not consider congestion's value on non-hedged firm transmission rights and benefits participants with non-congested and counter-flow firm rights.

Keith Collins lays out the MMU's position before the SPP Board of Directors and Members Committee. | *© RTO Insider LLC*

SPP's Market Monitoring Unit (MMU) weighed in on the debate, supporting staff's recommendation for No. 5 that considers congestion's value on firm transmission rights not hedged through the allocation process and calls for a third round of ARR nominations. It said the Evergy proposal was an incremental improvement to the current process, while staff's proposal creates three times more equity over the current process.

Congestion-hedging improvements were one of 21 proposals brought forth by the Holistic Integrated Tariff Team and approved by the board in 2019. Staff first pushed for optimizing the flow of energy in a direction that results in a charge to the transmission congestion rights (TCRs) holder, or *counter flow optimization*, to address concerns about how TCRs are awarded and the efficiency of the current process. However, it never gained traction in the stakeholder process and eventually was replaced last year by a hybrid approach that focuses first on equitably allocating the congestion rights instruments and then increases the pool of awards available. (See *SPP Congestion-hedging Recommendations Gain Traction*.)

The package did not include a recommendation to give more opportunities for all market participants to receive long-term congestion rights. CAWG and staff are working together in considering load-serving entities' ability to request and obtain LTCRs, making the awards finite and adding capacity factors and/or accredited capacity requirements to candidate LTCRs.

The topic was the primary reason the package drew opposition from renewable energy interests during the Members Committee's advisory vote for the board, which passed 16-6 with one abstention. EDP Renewables' David Mindham said transmission customers still are faced with a "major" equity issue when trying to deliver power through their transmission service.

"We enter those agreements willingly and most of my colleagues are looking to shed those agreements as quickly as possible," he said, "as SPP has a strategic priority to optimize seams. Without issue No. 1 being part of the discussion, there is a major incentive for us to not wheel power associated with a major carrier that doesn't align with the strategic priorities of SPP."

Arguing that "perfection should not be the enemy of the good," SPP's Antoine Lucas, vice president of markets, said the nine recommendations will make "notable progress" with financial transmission rights.

"I still believe that recommendation one will have the most significant incremental impact," he said. "If we're able to make the progress that I believe that we can make on recommendation one, I believe that the impact or the difference between the two approaches or recommendation five really starts to level out to some degree. I really think it has the ability to bridge that divide."

The RSC unanimously endorsed the package's recommendations July 24 after it cleared the CAWG on an 8-4 vote.

General counsel Paul Suskie said staff now can begin turning the package's eight approved items into revision requests.

Board, RSC Endorse Winter Obligation

The board and RSC also both endorsed a revision request that adds to the tariff a winter resource adequacy requirement for load-responsible entities (LREs) bound by the grid operator's recent planning reserve margin (PRM) increase.

The measure (*RR549*) applies the same level of validation, study and assessment requirements to the winter season (December through March) that currently applies to the summer season, including a deficiency payment for capacity shortfalls. It also assigns an annual deficiency payment to prevent duplicate payments for the same capacity within an annual timeframe.

The board approved RR549 although the 23-person Members Committee only gave it 10 concurring votes against nine in dissent and four in abstention. SPP staff normally does not report the results of the directors' ballots.

David Kelley, SPP's vice president of engineering, said a winter season obligation is the culmination of a large amount of work by several stakeholder groups. That work now is focused within SPP's Resource and Energy Adequacy Leadership Team. (See *SPP REAL Team Endorses Winter Resource Requirement*.)

"This is kind of the first major policy decision that sets the cornerstone for the rest of these policies to be effective," he said.

"From my perspective, there's a desire to get going with making the current resource adequacy an actual requirement ... that we can hold people accountable to it while we continue to work on other aspects of the policy," SPP CEO Barbara Sugg said.

The RSC approved the tariff change in a 9-3 vote. The Markets and Operations Policy Committee narrowly approved RR549 earlier in July. (See *SPP Markets and Operations Policy Committee Briefs: July 10-11, 2023*.)

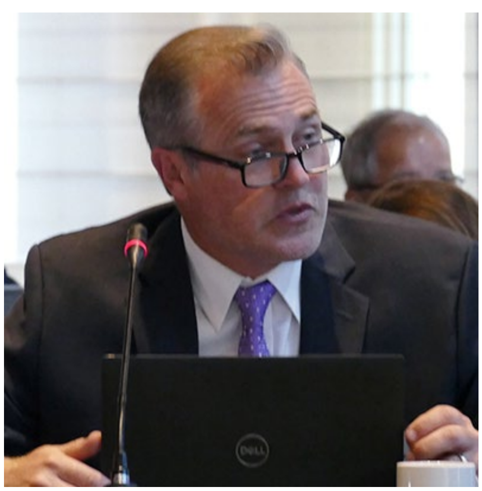
Western Area Power Administration's Lloyd Linke, holding a proxy for NorthWestern Energy's Bleau LaFave, urged delay to give winter-peaking utilities greater clarity in how winter outages will be treated.

"The treatment of outages being the same or similar in the summer season as opposed to the winter season ... is such a critical aspect of the whole program for us," he said. "There is just a strong concern by the winter-peaking utilities that, 'Yeah, it sounds good. It sounds like everything's gonna be hunky dory. And we're going to have the same sort of requirements, summer and winter.' We just like to see that particularly baked into it initially so that we have some certainty."

Keith Collins, the MMU's vice president, repeated the same concerns with RR549 that he expressed during earlier MOPC and RSC meetings. While he supports a winter resource adequacy requirement (RAR), he said that, as written, the tariff revision doesn't include language requiring a reasonable expectation of availability for resources used toward RAR; it doesn't achieve the policy's goal for the deficiency payment; and the deficiency calculation does not send the appropriate signal to improve available accredited capacity.

$50M Budget for Western Services

Members and directors approved nearly $50 million in budgets endorsed by the Finance Committee for two prongs of SPP's expansion into the Western Interconnection, Markets+ and RTO West.



Lanny Nickell, SPP | *© RTO Insider LLC*

The approval sets the Markets+ budget at $9.7 million to fund its development of a tariff and associated protocols for a day-ahead market, designed for those not yet willing to join an RTO. The funds were collected upfront from potential market participants; work began earlier this year and is targeted to conclude with a FERC filing by 2025.

Almost all the costs are for labor. After the tariff is filed, SPP also has contractual agreements in place to bill the parties $500,000/month to attain FERC's approval and to develop the market's second phase funding agreement.

The RTO West's $39.9 million budget sets aside $20.3 million for labor and $8.7 million for software, including maintenance. SPP has begun the same new member stakeholder process used in previous expansions to support the interested parties' evaluation of RTO membership.

Five parties already have signed commitment agreements that obligate them to reimburse SPP for costs incurred should membership not be consummated. Deadlines have been established for the remaining parties to sign agreements.

RTO West will add 6 GW of capacity to SPP's current market, creating a contiguous RTO market footprint with 59 GW of capacity that "optimizes trade by leveraging resource mix, geographic, and time zone diversity."

SPP says RTO West will save members about $194 million annually in market savings, although some stakeholders expressed a wait-and-see attitude. Evergy and American Electric Power cast opposing votes when the Members Committee endorsed the RTO West budget 19-2, with two abstentions. AEP abstained from the Markets+ budget vote, which the committee unanimously endorsed.

Staff, led by Lucas and Bruce Rew, senior vice president of operations, made their cases before the Finance Committee in March.

"I'm grateful that Antoine and Bruce are in the room. They survived the Inquisition that the Finance Committee performed, and you'll be happy to know they're no longer limping, so they should be able to quickly get to a mic in case they need to answer a question I can't," SPP's Lanny Nickell said, injecting some droll wit into his presentation.

Order 881 Compliance Change Passes

The board signed off on *RR565* that staff and stakeholders say will bring SPP into compli-

SPP News

ance with FERC Order 881. On Friday, staff filed the tariff change with the commission and asked for an effective date of July 12, 2025 (*ER22-2339*).

The commission earlier had granted the grid operator's extension request of Aug. 1.

Order 881 directs transmission providers to use ambient-adjusted ratings (AARs) for short-term transmission requests — 10 days or less — for all lines that are affected by air temperature. Seasonal ratings will be required for long-term service. (See *FERC Orders End to Static Tx Line Ratings*.)

SPP said in its response to a May deficiency letter that it will use updated AARs as the relevant transmission line ratings for reliability unit commitments and any other market process associated with the day-ahead and real-time markets. It also explained its timelines for calculating or submitting AARs and addressed systems and procedures so transmission owners can update their line ratings at least hourly.

The MMU, as it said before MOPC earlier in July, again said the revision falls short of compliance with FERC's order. (See "MMU Comments Bypassed in Order 881 Compliance," *SPP Markets and Operations Policy Committee Briefs: July 10-11, 2023*.)

The Monitor said the revision does not clearly delineate the expected roles between TOs and transmission provider and the use of AARs in market processes. It recommended edits that obligate TOs to provide factual line ratings and methodologies and that add transparency into the market processes' line ratings.

"The tariff does not have the same responsibility requirements on transmission owners to provide information for transmission line ratings that are in fact accurate and factual," Keith Collins, the MMU's vice president, said. "That's the type of language we see as being incredibly important to be included as the responsibilities that exist for the transmission owner."

"Keith makes a good point," the Advanced Power Alliance's Steve Gaw said before the RR565 votes. "I think FERC might see this as an issue, but I also think that it's been to the stakeholder process and for the sake of efficiency, we should probably move forward and let FERC wrestle with this issue."

SPP Prepping EPA GHG Comments

Oklahoma Gas & Electric's Emily Shuart suggested during the Strategic Planning Committee's (SPC) discussion of the Environmental Protection Agency's greenhouse gas rule that SPP use its comments to stress the importance of resource adequacy and retention.

EPA in May proposed to reduce carbon dioxide emissions from coal- and gas-fired power plants by requiring them to use carbon capture and sequestration and co-firing hydrogen. Comments on the rule are due Aug. 8. (See *EPA Proposes New Emissions Standards for Power Plants*.)

Shuart proposed that SPP use the comments, being developed by staff and an advisory stakeholder committee, to further engage with EPA "to secure our efforts in resource retention and making sure that there's education on the resource adequacy and reliability issues that are coming into question right now, not just with the greenhouse gas proposals but with a number of their pending regulations and proposals."

"I think there's a role for us as the RTO, particularly one that is structured where we are geographically with resources, that we have to get in front of the EPA and let them know the challenges that we're facing and how those are exacerbated by premature retirements," she said.

Sugg agreed, saying the grid operator is in an "independent spot." She said that, recognizing that members "are on both sides of the equation and concern areas," the dialogue will continue between staff and the SPC.

Board Search Underway

Sugg, who also chairs the Corporate Governance Committee, said the group will conduct interviews in August for the board vacancies soon to be created by the retiring Larry Altenbaumer and Josh Martin.

"Despite our best efforts, [Altenbaumer and Martin] are riding off into the sunset at the end of this year," she said.

The two will take nearly 38 years of board experience with them into retirement. A director since 2005, Altenbaumer replaced long-time board chair Jim Eckelberger in 2018 before handing the role to Susan Certoma earlier this year. Martin has chaired the Oversight Committee for more than a decade.

Director Liz Moore has accepted a nomination for a second three-year term. The Members Committee will vote on nominations to the board in October.

Sugg also said the CGC has nominated ITC Great Plains' Patrick Woods and Basin Electric Power Cooperative's Jeremy Severson to serve terms on the Members Committee ending in 2025. They currently are filling the vacancies left by Brett Leopold, who left ITC earlier this year, and Tom Christensen, who has retired from Basin Electric.

Woods and Severson will be up for election during the October board meeting.

Directors OK 20-year Assessment Report

The board approved a slim consent agenda, but not until the 20-year transmission assessment's report was pulled off and endorsed separately. Omaha Public Power District's Joe Lang asked that the assessment be considered separately after SPP distributed an addendum to the report the day before.

Lang said he didn't have any issues with the addendum, saying it explained that a simulation issue prevented a flowgate from being analyzed. Staff's further review identified a 345-kV line as providing the most future benefits, he said.

The Markets and Operations Policy Committee unanimously approved the report three weeks ago. ITC Holdings' Alan Myers, the committee's chair, told the board the addendum wouldn't have "materially changed anybody at MOPC." (See "20-year Tx Assessment Endorsed," *SPP Markets and Operations Policy Committee Briefs: July 10-11, 2023*.)

According to the *report*, SPP will need between 900 and 1,200 miles of new EHV lines that could enable carbon dioxide reductions of up to 93%. The study team evaluated 463 solutions during its 35-month analysis; It found the solutions could cost as much as $1.55 billion in engineering and construction costs across its reference case and emerging technologies cases, with a benefit-to-cost ratio of $1.57 billion to $4.35 billion.

The assessment does not request notifications to construct, but it did recommend 13 new transmission projects to resolve congestion and other constraints. The board's consent agenda also resulted in approvals of:

- Sunflower Electric Power's Ray Bergmeier and City Utilities Springfield (Mo.) to fill vacant seats on the Strategic Planning Committee as transmission-owning and transmission-using members, respectively;
- A sponsored upgrade study for Omaha Public Power District for 161-kV work in Omaha, Neb.; and
- Withdrawing Lea County (N.M.) Electric Cooperative's notification to construct for a 115-kV network upgrade following another project's cancellation. ■

— Tom Kleckner

Company News

Down Day: Xcel, AEP, CenterPoint Shares Slide After Earnings

By Tom Kleckner

Xcel Energy highlighted a busy day for utility earnings calls Thursday with weaker results the company blamed on inflationary pressures and a lower-than-expected return on equity from a rate case in its home state of Minnesota.

The Minnesota Public Utilities Commission in June *approved* a $306 million, or 9%, rate increase over three years for Xcel, below recommendations from the state's Department of Commerce and an administrative law judge. Xcel initially requested a $677 million, or 21%, increase before dropping its ask to $498 million and then $400 million.

The Minneapolis-based company *reported earnings* of $288 million ($0.52/share) for the quarter, down from $328 million ($0.60/share) from a year earlier.

CEO Bob Frenzel said the company is working to offset the effects of the headwinds and is continuing to "lead the nation's clean energy transition."

In June, the PUC also approved Xcel's plan to construct a multiday energy storage system that will test Form Energy's 10-MW/1,000-MWh iron-air battery system at the utility's 710-MW Sherco solar site. The battery is expected to come online in 2025. (See "Long-duration Storage is Key," *Overheard at EEI 2023*.)

"We've always been focused on new technology, new research, development and deployment of new technologies to achieve our 100% goal," Frenzel said, referring to the company's first-in-the-nation commitment to 100% carbon-free electricity. "Long duration energy storage is a critical part of the energy future. A 100-megawatt-hour battery ... [is] a nice asset class as we think about periods when the wind doesn't blow and the sun doesn't shine."

Frenzel also addressed a recent report following an investigation by the Boulder County (Colo.) Sheriff's Office into a 2021 wildfire that caused about $2 billion in property losses. The report found Xcel subsidiary Public Service Company of Colorado (PSCo) responsible for one of two ignitions. Xcel disclosed the report in its earnings release and said that if PSCo is found liable and is required to pay damages, the amounts could exceed insurance coverage of approximately $500 million.

"Because of the pending litigation that has been filed, we're not in a position to discuss the fire in more detail at this time," Frenzel said. "We will vigorously defend ourselves and move forward to presenting our position in court."

Xcel's share price dropped $2.18 (3.35%) during a down day on Wall Street, closing at $62.87. The Dow Jones Industrial Average lost 237 points, ending a historic streak of 13 straight gains.

AEP Continues with Asset Sales

American Electric Power said Thursday that the "de-risking" and "simplification" of its business continues to pick up speed with two non-core transmission ventures being put up for sale.

CEO Julie Sloat told financial analysts during the company's quarterly earnings call that AEP will soon launch the sale of its interests in the Prairie Wind and Pioneer transmission projects. The former are 345-kV facilities in Oklahoma and the latter 765-kV facilities in Indiana.

AEP could also soon put its share of Transource Energy, a competitive transmission developer, on the block once it completes a strategic review.

AEP also plans to close the sale of its 1.37-GW unregulated renewables portfolio to IRG Acquisition Holdings in August and is on track with other transactions involving its AEP Energy retail and AEP OnSite Partners distributed resources businesses and its 50% share in the New Mexico Renewable Development joint venture.

"Our ongoing active management of the company strengthens our ability to prioritize investments in our regulated businesses," Sloat said.

The Columbus, Ohio-based company *delivered* second-quarter earnings of $521 million ($1.01/share), compared with earnings of $525 million ($1.02/share) for the same period a year ago.

During the quarter, AEP received regulatory approval to add nearly 2 GW of new wind and solar generation in Oklahoma, Arkansas and Louisiana. It also has approvals in place for $5.2 billion of its five-year, $8.6 billion regulated renewables capital plan and has filed for approval of $1.7 billion in additional renewable projects.

AEP's share price closed Thursday at $85.26, a drop of $2.35 (2.6%) on the day.

CenterPoint Energy Takes $74M Hit

CenterPoint Energy also reported quarterly financial results on Thursday, *delivering earnings* of $106 million ($0.17/diluted share) that included a loss and expense of $74 million ($0.12/share) related to the divestiture of *Energy Systems Group* (ESG).

The Houston utility earned $179 million ($0.28/diluted share) during the second quarter a year ago.

CenterPoint *sold its interest* in ESG for about $157 million to EEG Holdings in May. ESG offers energy efficiency and sustainable energy solutions.

The utility's share price closed at $30.36 Thursday, an 85-cent loss. ■

Xcel Energy CEO Bob Frenzel (right) with Form Energy's Mateo Jaramillo during June's EEI leadership forum | *© RTO Insider LLC*

Company Briefs

First Solar Announces 5th US Factory

First Solar last week announced it will build its fifth U.S. factory at a site yet to be determined.

The company said it will invest as much as $1.1 billion in the new factory, which will increase First Solar's manufacturing capacity by 3.5 to 14 GW by 2026.

More: *CNBC*

Battery Maker EnerDel Files for Bankruptcy

Battery manufacturer EnerDel filed for Chapter 7 bankruptcy on July 13, claiming nearly $14 million in assets and $47 million in liabilities, according to the bankruptcy petition.

EnerDel brought in $18.2 million revenue in 2022 and was on track to fall short of that number in 2023, with just $8.6 million in revenue in the first half of 2023. It also owed $31 million to more than 200 creditors.

More: *Indianapolis Business Journal*

Xcel Energy Files Proposal for Solar, Storage Projects

Xcel Energy last week said it has filed proposal plans in Texas and New Mexico to invest $770 million in existing generating facilities by extending the life of two gas-fueled units, constructing solar generating systems, and adding battery storage.

In proposals filed with the New Mexico Public Regulation Commission and the Public Utility Commission of Texas, Xcel presented its plan to extend the life of two natural gas units at its Cunningham-Maddox Generating Complex near Hobbs, New Mexico. The plan also calls for the construction of three solar facilities — two at Cunningham Station and one at Plant X Generating Station near Earth, Texas. A battery system is also planned at Cunningham.

Xcel Energy expects to have the resources online by 2026 and 2027.

More: *KFDA*

CEO Lund Leaving AES Indiana

Kristina Lund, the president and CEO of AES Indiana since 2020, will leave the utility at the end of July.

Lund plans to become the president of a renewable energy company, an AES spokesperson said.

Ahmed Pasha, the utility's CFO, has been named acting president.

More: *Inside Indiana Business*

Exelon Names Honorable EVP of Public Policy, Chief External Affairs Officer

Exelon last week named Colette Honorable as the company's executive vice president of public policy and chief external affairs officer, effective Sept. 5.

Honorable will join Exelon from law firm Reed Smith, where she has been a partner since 2017 and a member of the executive committee since 2021.

Honorable will be based at the company's D.C. offices.

More: *Exelon*

Nowak Joins ATC as VP of Regulatory and Government Affairs

ATC last week announced that Ellen Nowak has joined the company as vice president of regulatory and government affairs.

Prior to joining ATC, Nowak was a commissioner at the Public Service Commission of Wisconsin.

More: *ATC*

Federal Briefs

White House Launches Methane Task Force

The White House last week held a summit aimed to address methane emissions and launched a new task force dedicated to the issue.

The White House said the new task force will seek to "accelerate" plans to reduce emissions and "advance a whole-of-government approach to proactive methane leak detection and data transparency, and support state and local efforts to mitigate and enforce methane emissions regulations." It did not specify what exactly it entails or who is on it, though it was described as "cabinet-level."

More: *The Hill*

TVA Adds Generation at Alabama Natural Gas Plant

The Tennessee Valley Authority last week brought three additional units at the Colbert Combustion Turbine in Tuscumbia, Ala.

The $500 million projects add about 750 MW with the new units.

TVA plans to add about 10,000 MW of generation by 2035.

More: *Alabama.com*

Canada Approves Hertel-New York Hydropower Tx Line

The Canada Energy Regulator last week approved its portion of the 1,250-MW Hertel-New York interconnection line that will bring hydropower to the U.S.

The permit means construction can begin on the 36-mile-long line that will link to the 339-mile-long Champlain Hudson Power Express line, currently under construction in the U.S.

Commissioning of the installations is scheduled for May 2026.

More: *Hydro Review*

Feds Propose $2B in PNW Grid Upgrades

The Bonneville Power Administration last week said its grid in the Northwest could use $2 billion in upgrades to meet rising demand over the next decade.

A set of 10 projects proposed by the federal energy wholesaler include more than 130 miles of new transmission lines across Washington, as the Pacific Northwest is expected to see up to 23% increases in peak energy demand over the next 10 years.

More: *The Seattle Times*

FERC Approves Transfer of Pleasants Power to Omnis Fuel Technologies

FERC last week authorized the transfer of Pleasants Power from Texas-based Energy Transition and Environmental Management to California-based Omnis Fuel Technologies after the companies signed a purchase agreement two weeks ago.

The authorization was subject to conditions, including keeping FERC informed of any changes in the application as long as FERC retains authority to issue future orders.

Pleasants Power is a 1,278-MW coal-fired plant, however Omnis said it plans to use the plant to produce hydrogen.

More: *The Parkersburg News and Sentinel*

Heat Waves Ramp up Burning of Fossil Fuels

Widespread heat waves across the county led U.S. natural gas demand at power plants on Aug. 26 to break a record set just a year ago — and then break it again the following day, climbing 3.6% in one day to more than 52 billion cubic feet, according to S&P Global Commodity Insights.

The World Meteorological Organization also declared July to be the hottest month on record.

Last year, nearly a fifth of the global increase in carbon dioxide emissions came from increased energy demand during extreme weather, the IEA said. Its report on global carbon dioxide concluded that summer heat waves were the primary reason that the U.S. and China, the world's two largest emitters, did not reduce their emissions for the year.

More: *The Washington Post*

State Briefs

ARKANSAS

Summit Utilities Seeks Extended Repayments

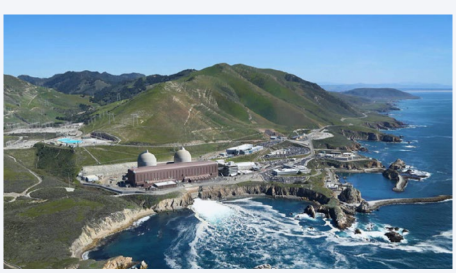
Summit Utilities, which has more than 47,000 customers behind on their natural gas bills, is offering ratepayers six extra months to set up repayment plans under a compromise the company has filed with the state Public Service Commission.

The PSC is expected to approve a plan that allows the company to again disconnect customers and assess penalties for customers behind on payments who don't establish a repayment plan. If approval comes this month, Summit will restart shutoffs and late fees in September. Disconnects and late fees have been suspended since November.

More: *Arkansas Democrat-Gazette*

CALIFORNIA

Report: Keeping Diablo Canyon Open Could Cost Ratepayers $45B



Extending operations of the Diablo Canyon nuclear power plant through 2045 could cost ratepayers as much as $45 billion, an analysis from the Environmental Working Group (EWG) found.

According to the report, if the plant stays online for two more decades, total costs to run the site could range from $20 billion to nearly $45 billion between 2023 and 2045.

The EWG analysis, based in part on testimony filed by the Utility Reform Network, estimated that keeping the plant open would likely require hundreds of millions of dollars every year. Because that cost would need to be passed on to the consumer, households could expect an increase between $55 and $124 per year.

More: *The Hill*

GEORGIA

Georgia Power Turns over Plant Vogtle Analyses to NRC, Unit 3 Operational

Georgia Power recently announced that Plant Vogtle's operator, Southern Nuclear, has turned over 364 inspections, tests and analyses to the NRC to assure that the plant's final reactor meets nuclear safety and quality standards prior to completion.

Georgia Power is awaiting the commission's approval to start loading fuel into Unit 4, which is expected to be completed by this fall or early 2024.

Meanwhile, the company announced Monday that Unit 3 has entered commercial operation. The unit is the first newly constructed nuclear unit in the U.S. in more than 30 years.

More: *Georgia Public Broadcasting*, *Southern Company*

KENTUCKY

Solar Project Planned on Former Starfire Coal Mine

Solar developer BrightNight, along with state officials, last week unveiled plans to invest $1 billion in a project that will sit on the former Starfire coal mine. The 800-MW project would be the largest in the state and have a 40-year lifespan.

Electric SUV manufacturer Rivian plans to buy 100 MW as renewable energy credits that can offset carbon emissions. Conservation organization The Nature Conservancy also plans to buy 2.5 MW for renewable credits to offset the emissions of its offices.

Construction is expected to be completed by 2030.

More: *Kentucky Lantern*

OHIO

Perry Nuclear Plant Seeks 20-year Extension

Energy Harbor recently filed an application with the NRC seeking a 20-year extension for the Perry Nuclear Power Plant.

The application seeks to push the plant's end date to Nov. 7, 2046. The facility would otherwise reach the end of its 40-year full-power operating license at midnight on Nov. 7, 2026.

More: *Crain's Cleveland Business*

Wind Farm Allowed to Proceed Following Ohio Supreme Court Ruling

The Ohio Supreme Court last week gave final approval to a permit for a 71-turbine wind farm that would span Huron and Erie counties.

A group of 19 residents around the project site, along with the Black Swamp Bird Observatory, asked the state Supreme Court to reconsider the approval of the certificate, saying it does not include protections to prevent noise from the turbines "from causing discomfort, annoyance, sleep deprivation and health disorders," along with risks to birds, bats and the local economy.

The court unanimously affirmed the Power Siting Board's order, saying the group did not do enough to establish that the board should not have approved the certificate.

More: *Ohio Capital Journal*

SOUTH DAKOTA

Xcel Customers Receive Bill Credits Because of Lower Rate Increase

The Public Utilities Commission recently approved a 5.85% rate increase for Xcel Energy, which is far less than the 17.9% hike that had been in effect since the beginning of 2023. Thus, Xcel customers are getting refunds on the difference, along with interest.

The average refund will be around $90. Xcel implemented the interim rate refund on July 18, while all bill credits were posted to customer accounts by July 19.

More: *KKRC*

TENNESSEE

Jefferson County Halts Battery Storage Development Until Jan. 2024

The Jefferson County Commission last week voted 16-1 to effectively ban the development of a battery storage system, barring departments and commissions from issuing permits or approvals.

The resolution prevents permits from being issued until at least Jan. 27, 2024. It also effectively creates a moratorium on BESS proposals until at least the same date.

More: *WBIR*

VIRGINIA

Dominion Gets Approval to Charge Customers for RGGI Participation

The State Corporation Commission approved a modified version of Dominion Energy's request to recover its costs for participation in the Regional Greenhouse Gas Initiative (RGGI).

Despite the state's pending withdrawal from RGGI, residential Dominion customers will see an additional fee of about $4.44 on their monthly bill beginning Sept. 1 to cover the utility's costs of participating in the market between July 31, 2022, and the end of this year.

The state is close to finalizing its withdrawal from RGGI following Gov. Glenn Youngkin's approval of a regulation repealing the state's participation. The regulation was published in the *Virginia Register* on Monday.

More: *Virginia Mercury*

Henry County Approves Solar Panel Cap

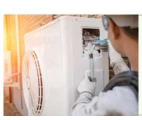
The Henry County Board of Supervisors last week approved an amendment capping the acreage allowed for solar farm development in the county.

The board approved a zoning ordinance amendment that will limit the total amount of acreage that can be permitted for solar development to 1% of the total land mass of the county. The county has about 382 square miles of land, which means the cap will limit solar to 2,445 acres. Currently, there are 10 approved solar projects that span 1,807 acres.

More: *WSET*

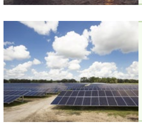
Mid-Atlantic & Southeastern news from our other channels

NJ Ramps up EV Purchase, Charger Installation Programs — NetZero Insider



NJ BPU Backs Building Decarbonization Plan Despite Opposition — NetZero Insider

Lawsuits Mount over NJ OSW Projects as Opposition Digs in — NetZero Insider



NextEra Energy Says Solar Supply Crunch Has Eased — NetZero Insider

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