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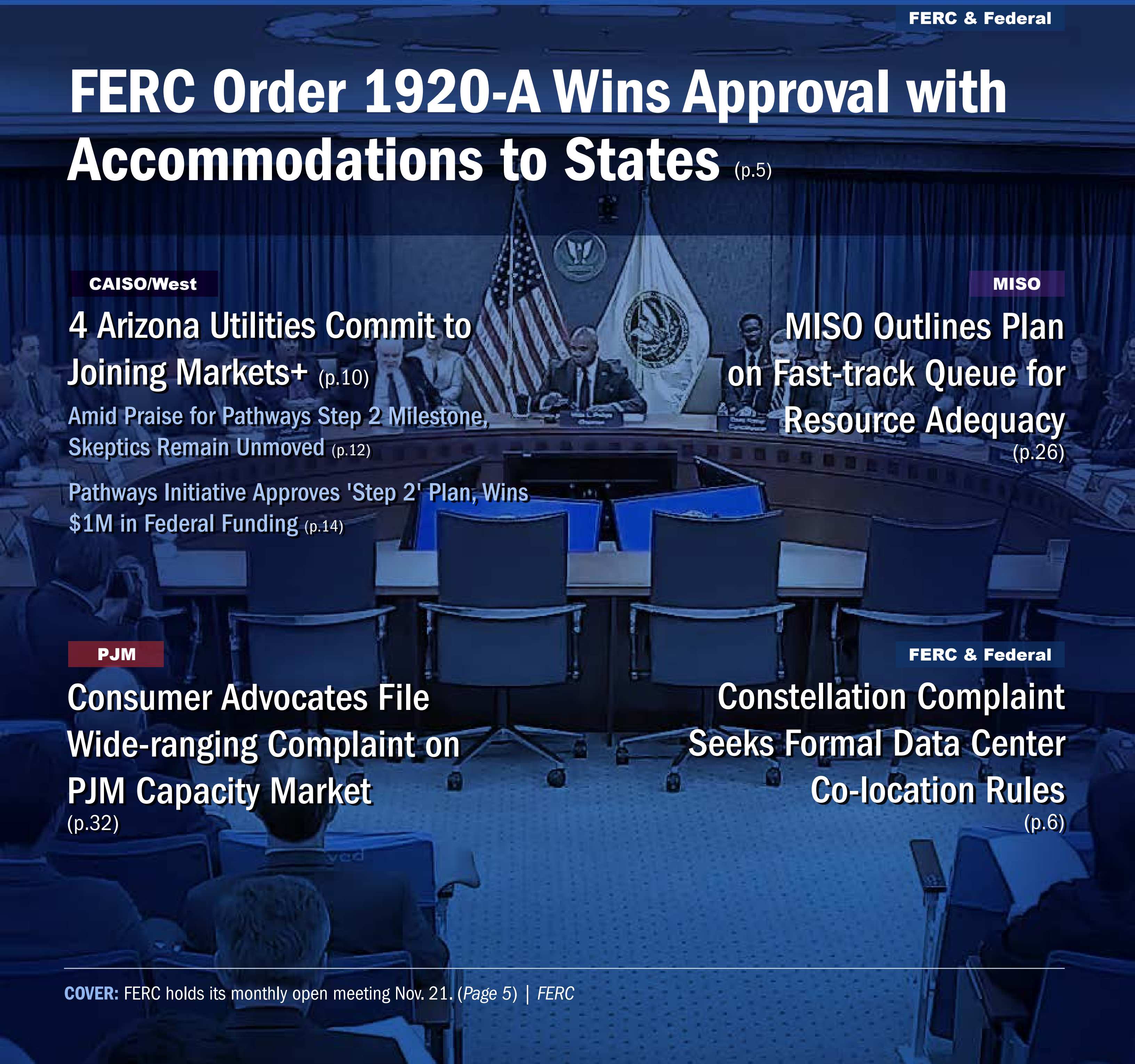
RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP



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RTO Insider
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By Steve Huntoon

Grid Apocalypse Not

By Steve Huntoon

Steve Huntoon

I was minding my own business the other day when *The Wall Street Journal* ran a special section with the lead article *"Five Ways to Disaster-Proof the Energy Grid."*

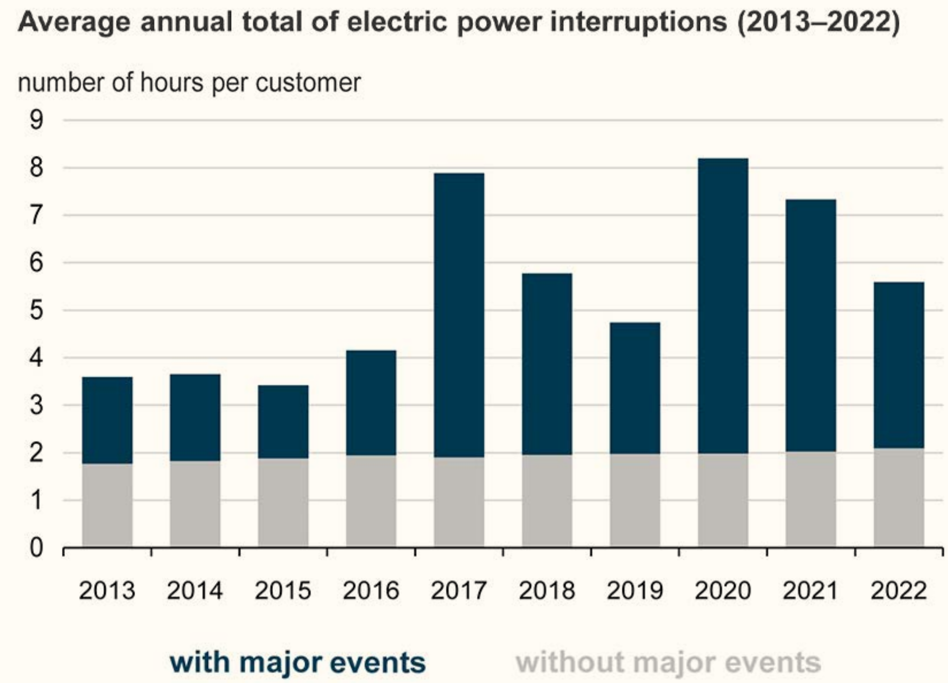
The article starts out claiming that recent extreme weather has pushed the "aging, overtaxed" grid to its limits, with outages "wreaking havoc on homeowners and businesses." The alleged culprit is climate change, which is said to get worse.

Flawed Evidence

The only empirical evidence given for these claims is data from the Climate Central organization purporting to show that widespread power outages have doubled from the early 2000s to the period 2014-2023. The problem with this data is that — per Climate Central itself in *an earlier report* — stricter Energy Information Administration (EIA) reporting requirements were widely implemented after 2003, so the years 2000-2003 must be disregarded in order to have apples to apples. If one looks at *Climate Central's data* for the 10-year period 2004-2013 and compares it with the 10-year period 2014-2023, the average number of outages goes from 78 per year to 91 per year. Not much difference.

An authoritative data source not mentioned by the *Journal* is the EIA, which has reported average annual hours of outage (aka interruption) per electricity customer from 2013 to 2022. That chart is reprinted *here*. The bottom part of each column shows the average outage hours without major events (principally weather); these basically are unchanged over 10 years, which suggests the grid is not "aging" and "overtaxed." My past articles disproving Chicken Little claims about the grid are *here* and *here*.

The top part of each column adds the average hours with major events (principally weather). The trend seems up, but not dramatically so.



Average annual total of electric power interruptions (2013-2022) | *EIA*

And let's put the average 5.5 hours of customer outage in 2022 in perspective. That's 99.94% reliability (5.5 divided by 8,760). Not "wreaking havoc" on customers — contrary to the Journal's claim.

Wrong Target

Credibility doesn't improve with the *Journal*'s suggested ways to "disaster-proof the grid." For starters, anyone who wants to know anything about "disaster-proofing the grid" should consult experts at NERC, the Institute of Electrical and Electronics Engineers (IEEE) and the national laboratories.

The experts *would explain* that more than 90% of customer outages originate on local distribution systems, not the transmission/generation bulk power system (BPS). This is important because all of the ***Journal***'s suggested ways to "disaster-proof the grid" are exclusively or predominantly tied to the BPS. Thus, even if they were sensible (which they're not, per below), they would have a negligible effect on customer outages.

Now, let's look at each one individually.

Artificial Intelligence

The *Journal*'s first suggested way to "disaster-proof the grid" is (of course) AI, which is said to enable better predictions to help better plan for extreme weather. My favorite example is replacing copper wiring with fiber-optic cable at substations vulnerable to flooding. The story says fiber-optic cable is "more resilient to saltwater and can be replaced more quickly if need be."

Minor problem: Fiber-optic cable does not conduct electricity. Oops!

By the way, if anything will "overtax" the grid, *it will be AI*. How ironic.

Batteries

Moving on, the *Journal*'s second way to "disaster-proof the grid" is "bolstering batteries." Right. I've explained why batteries are an incredibly profligate way to provide carbon-free reliability. In May I *estimated* the annual costs of covering renewable droughts in a carbon-free California relative to other no/low carbon options:

- Long-duration battery storage: $23.9 billion

Counterflow

By Steve Huntoon

- Gas plants with carbon credits: $1.1 billion
- Gas plants with CCS credits: $1.6 billion
- Gas plants with CCS retrofit: $4.4 billion

See the difference?

Microgrids

The *Journal's* third suggested way is microgrids. As *I explained* nine years ago, microgrids ignore the incredible efficiency of grid integration. *The latest*, greatest microgrid is an incredible waste of Commonwealth Edison customers' money.

Microgrids at U.S. military bases actually reduce national security by substituting microgrids for building-specific backup generation that — unlike a base microgrid — is not vulnerable to distribution-level outages (which make up 87% of all base outages) and *cybersecurity threats*.

Advanced Conductors

The fourth way given is "better, stronger transmission lines." Yes, we've known for years that reconductoring with advanced conductors can increase transmission capacity on existing lines, and *I've been a fan*. But the various options come with their own varying characteristics (such as "rated breaking strength"), as *this report* shows. Could they somehow "disaster-proof" the grid or even the BPS? No way.

Demand Response

The fifth way given is "controlling demand," aka demand response. Demand response is best understood as a counterpart to generation resources — reducing demand on command is the flip side of increasing generation on command. Yes, of course, economic demand response should be implemented, just like all economic resources that can be called upon when needed. But DR can no more "disaster-proof the grid" than other dispatchable resources.

The irony is that those ostensibly concerned with grid reliability want to eliminate dispatchable generation resources (gas, oil, coal), thereby enabling, rather than avoiding, future disasters.

OK, I'll stop ranting. ■

— Columnist Steve Huntoon, a former president of the Energy Bar Association, has practiced energy law for more than 30 years.

National/Federal news from our other channels

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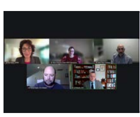
NetZero Insider

Corporate Solar Development Continues to Grow

NetZero Insider

FERC Approves Adoption of Latest NAESB Standards

ERO Insider



Panelists Call ITCS 'Excellent Starting Point'

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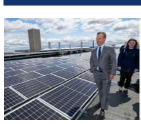

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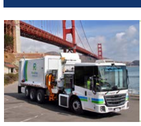

CARB Clean Vehicle Incentives Down Sharply for 2024/25

NetZero Insider

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

FERC/Federal News

FERC Order 1920-A Wins Approval with Accommodations to States

By James Downing

WASHINGTON — FERC on Nov. 21 voted to approve Order 1920-A, which upholds most of the original's changes to the commission's rules on transmission planning and cost allocation while giving more consideration to states (*RM21-17-001*).

Commissioner Mark Christie (R), who voted against Order 1920 when it was issued in May, joined the Democratic majority in issuing the revised order, which addressed his main criticism of the original: Transmission providers will now be required to file any cost allocation proposals agreed to by states in a region alongside their own for the commission to consider.

The original order gave state entities six months to agree on a cost-allocation method for transmission projects, but planners could simply ignore it and file their own method. It represented a change from the Notice of Proposed Rulemaking that had drawn Christie's support in the first place. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

FERC issues major orders like 1920 under Section 206 of the Federal Power Act, the same statute that covers complaints about utility rates and ISO/RTO rules. With Order 1920, FERC had to find that regional planning efforts around the country were leading to unjust and unreasonable rates and then come up with a just and reasonable replacement rate, Christie said at the open meeting.

"The changes made today in Order No. 1920-A to the replacement rate set by Order No. 1920 go a long way [toward] restoring the state role to what the NOPR promised, and I am pleased to support these changes," he wrote in a partial concurrence. "I express my deep appreciation to my colleagues for their willingness to engage in good-faith negotiations leading to these important changes to the replacement rate."

Why This Matters

Moving forward on rehearing with a broader base of support means FERC's transmission planning and cost allocation rule should be stronger against legal challenges, which are already in motion.

"This order builds upon an already strong Order No. 1920 and will further enhance the ability of state regulators to provide their important perspectives on the much-needed new transmission facilities our nation needs to ensure our grid can serve the significant growth in demand for electricity," Chair Willie Phillips said.

Other changes Christie applauded include a requirement that if a transmission provider wants to change a cost-allocation agreement after it has gone into effect, they will have to consult with state regulators. It will also allow the State Agreement Approach in PJM, which New Jersey used to plan connections for state-backed offshore wind, to stay in place under the new regional planning regime.

Christie also noted in his concurrence that "the requirement in Order No. 1920 that large corporate power-purchasing preferences must be a factor in planning long-term scenarios is explicitly removed. That was one of the most unconscionable, special-interest driven features of Order No. 1920, directing transmission providers to plan hundreds of billions of dollars of transmission projects to subsidize the power-purchasing preferences of huge multinational corporations and shifting the costs to residential and small-business consumers already struggling to pay their monthly power bills."

That means expensive transmission lines to connect corporate demand with resources they have contracted with will not be cost allocated to all customers in a region, he added.

Commissioner David Rosner said he was proud to vote out a "bipartisan order" that makes meaningful changes to Order 1920 based on the rehearing requests but still fulfills the original's purpose of identifying needed regional transmission infrastructure that makes the country more secure.

"The need for this rule is urgent and obvious," Rosner said. "In conversations I have had around the country these last few months in my new role, I have come to see that there is broad agreement that we have a pressing need for more infrastructure."

New large customers are looking to connect to the grid while the uses of electricity are expanding into new areas of demand, while the interconnection queues are overflowing with resources that Order 1920-A will help get connected to the grid, he added.

FERC holds its monthly open meeting Nov. 21. | *FERC*

Commissioner Judy Chang said Order 1920-A should get the country building major transmission lines.

"Based on that experience, I think Order 1920 — and now Order 1920-A — is a very strong order, and substantially improves transmission planning and helps to solve the cost allocation problem that we've been talking about for the last 20 years," Chang said.

Failing to agree on cost allocation leads to a logjam of transmission projects that the new rule should help to break up, she added.

Commissioner Lindsay See (R) said she recused herself from participating in the order on the advice of FERC's designated ethics official, but she has "been really encouraged by what I've heard about the process that led to it. This order involves some of the hardest and most important issues before the commission, [and] I've heard from my colleagues that it reflects many hours of serious discussion trying to understand different points of view.

FERC had not published the text of the order by the close of business Nov. 21, so several stakeholders declined to comment until they had actually read it.

But Grid Strategies President Rob Gramlich, who has long supported the kind of changes in Order 1920, said he liked that FERC is moving forward with the new planning and cost allocation rules.

"The states that were concerned should be very happy," Gramlich said. "It's kind of a bipartisan, FERC-state kumbaya moment. No one got everything, everyone got something."

Christie's concurrence cuts the legal and political risk, he added.

"Hopefully most states lay down their arms and start participating in planning," Gramlich said. ■

FERC/Federal News

Constellation Complaint Seeks Formal Data Center Co-location Rules

By James Downing

Constellation Energy filed a complaint against PJM at FERC on Nov. 22, opening up another regulatory front in the debate over co-locating data centers at existing nuclear plants (*EL25-20*).

Constellation alleges that PJM's tariff is unfair because it does not contain rules for interconnected generators to follow when seeking to provide service to fully isolated, co-located load.

The issue already was in front of FERC in other proceedings, with the commission taking a universal look at co-located load in a recent technical conference. (See *FERC Dives into Data Center Co-location Debate at Technical Conference*.)

Exelon, from which Constellation was spun off, also has pending reforms to its interconnection rules that led to protests from the nuclear plant owner. (See *Exelon, Constellation at Loggerheads over Data Center Co-Location*.)

"While nothing in the tariff suggests any prohibition of fully isolated co-located load, some local utilities are taking advantage of the lack of tariff rules to thwart competition to serve large end use loads, thereby delaying by several years and significantly increasing costs to serve data centers that are critical to national security, economic development and other national priorities," Constellation's complaint said. "This lack of tariff rules is allowing transmission owners across the PJM system to treat generators seeking to serve fully isolated co-located load differently."

Calvert Cliffs Clean Energy Center in Lusby, Md. | *Constellation Energy*

PJM released guidance for the issue in April 2024, which explains how the RTO has been reviewing co-location. The complaint said that should be included in the tariff. FERC might decide that it has to weigh in on other issues, but those could be dealt with in a paper hearing.

The complaint argues that rules are needed so market participants understand what they have to do to enter into generator co-location deals. They also would ensure utilities understand the FERC jurisdictional rules applicable to fully isolated, co-located load and "cease exercising their monopoly power to thwart competition."

"It is necessary to establish consistency across the PJM footprint and avoid the current circumstance of each of the transmission owners in PJM deciding whether and to what extent they will follow PJM's guidance," the complaint said. "Otherwise, we will be left with a mishmash of co-location rules at the federal level that are driven by the self-interests of each of the transmission utilities."

That mishmash already is starting to happen based on how different Exelon's pending rules would treat co-located demand compared to how PPL Electric Utilities dealt with the 300-MW data center co-located at the Susquehanna nuclear plant.

Data centers are a national security priority due to the new technologies driving them, such as artificial intelligence. Their increasing size has made them difficult to connect to the grid, as that often requires new transmission. Building out the required lines takes several years and leads to higher costs for other consumers, the complaint said.

"As a matter of simple engineering, it is more efficient to locate large loads next to large generation, when possible," Constellation said. "One longstanding option that has been available to any load since the beginning of open access has been to connect directly to a generator either fully independent of the network grid or with a reduced reliance on the grid."

Data centers have pursued contracts for fully isolated, co-located load, "networked co-located load" where they rely partly on the grid and partly on a nearby power plant, and a "networked load" configuration that relies entirely on the grid. The last two have formal rules in PJM's tariff, but fully isolated co-located load lacks formal rules, with the tariff also saying nothing that indicates the configuration is inconsistent with the RTO's rules.

Why This Matters

The complaint was prompted partly by FERC's denial of the expansion of a co-located data center at the Susquehanna nuclear plant and adds another pending item for the regulator to deal with on the subject of load locating alongside power plants.

The issue of the less formal guidance on co-location came up when FERC recently rejected the expansion of a co-located data center at the Susquehanna nuclear plant. (See *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.) The amendments to the Susquehanna deal were proposed in large part so PJM's guidance would be binding on the parties.

FERC rejected them in part because it questioned whether the RTO planned to offer interconnection services on equivalent terms to all similarly situated interconnection customers. FERC's order acknowledged the guidance was "not part of the PJM tariff, has not been approved by the commission and was not before the commission in the instant filing."

The complaint notes that PJM has completed studies for potential co-located loads at three Constellation generation sites, which indicated none of those would have been able to draw power from the grid.

Exelon reviewed the deal at Constellation's LaSalle Clean Energy Center in Illinois, but then refused to do so at the other two units, insisting that the generation owner or its customer first must apply for retail service and designate what sort of wholesale transmission service it would take from Exelon. The utility holding company then stopped working with the data center at the LaSalle plant, the complaint said.

Connecting a major data center to the grid can take five to 10 years, and in a global race for new technology, any delay is harmful to the national interest, the complaint said.

"This interconnection delay imposes unquantifiable risks and costs to the national economy and security and advances in AI," the complaint said. "Each year that hyperscale data centers await interconnection to the grid risks another year of losing ground to competing nations." ■

FERC/Federal News

AEU Report Shows Major Economic Benefits from Quicker Queues

By James Downing

Fixing the interconnection process to speed up the development of new generation could add $100 billion in economic benefits, according to an analysis released Nov. 21 by Advanced Energy United.

Improving interconnection processes around the country could lead to $57 billion in economic benefits and 667,000 job-years from increased solar energy deployment and $42 billion and 376,000 job-years from increased onshore wind deployment, according to the report, "How Interconnection Reform Can Accelerate Clean Energy Deployment."

"Our nation's electricity demands are growing, and these broken interconnection processes are standing in the way of Americans building the energy projects we need to thrive," AEU CEO Heather O'Neill said in a statement. "Fixing interconnection would unleash job-creating energy projects and deliver an economic boom in states across America. If states can more quickly build the poles and wires needed to connect new electricity resources to the power grid, they will unleash their economic potential, lower electricity bills for residents and improve energy reliability for all."

Generators coming online in 2023 averaged five years in the queue, from when they requested interconnection to commercial operation, compared to an average of just two years from 2000 to 2007.

FERC has attempted to address the issue with orders 2023 and 1920, and the report argued that states can support and build on those efforts by engaging in implementation and pushing for supplemental reforms.

"In the United States, almost 2,500 GW of non-emitting power generation and energy storage capacity are seeking to interconnect, equivalent to double the capacity of all generation sources currently online in the United States," the report says. "Legacy interconnection processes were established decades ago to individually evaluate a small number of large, predominantly coal and natural gas power plant proposals, and these processes are ill-suited to evaluate thousands of more geographically distributed wind, solar and energy storage projects."

The precise impacts of speeding up the queues will take years to play out, but the report offers an illustrative analysis showing how accelerating them can benefit the economy.

Under one of the scenarios, attrition of projects initially increases by 25% this year, which reflects a "purging" of the queues prompted by Order 2023's higher financial requirements. But as additional improvements play out, project attrition is expected to fall by 50% from historic rates, while a business-as-usual case would see a 10% increase.

The report includes state projections (for the Lower 48 except Texas) for projects getting through the queue quicker and what benefits that would bring to their economies.

| Shutterstock

"Results vary between states, which is to be expected, as interconnection requests reflect renewable energy resource potential, state policy support and local project development considerations such as land availability, perceived permitting complexity, local construction costs and more," the report said. "Nonetheless, each state sees incremental renewable energy deployment with interconnection reform."

For most states, implementing changes will lead to an appreciable increase in renewable projects, with California, for instance, seeing 147 TWh in additions by 2030, compared to 112 TWh under business as usual.

One clear group of exceptions is those states banking on large offshore wind contracts — Connecticut, Delaware, Maryland, Massachusetts, New Jersey and Rhode Island — for most of their incremental renewable growth. The successful deployment of offshore wind depends on other factors, the report says.

"In a few states, successful interconnection reform leads to a significant increase in renewable generation such that generation in 2030 exceeds state [renewable portfolio standard or clean energy] requirements," the report says. "New Mexico and Arizona show renewable energy generation increases that outstrip state requirements, showing that each state is well positioned for exporting first-rate solar and wind-generated electricity."

The report suggests that states advocate for transmission providers to build trunk lines that aid interconnection and fast-track interconnection requests that are proposed for areas with available grid capacity.

It also suggests tailoring analyses to requested levels of interconnection (capacity- or energy-only), standardizing study assumptions, evaluating alternatives to traditional transmission upgrades, using automation, and using independent monitors to oversee the process and recommend improvements.

Another suggestion is to expedite construction of needed upgrades by adopting industry best practices and proactively addressing supply chain constraints.

"By engaging directly with FERC, pursuing available federal funds and calling on their regional grid operator to fulfill their responsibility to provide reliable and low-cost electricity, states can maximize economic opportunities made possible by more abundant solar and wind projects," O'Neill said. ■

FERC/Federal News

Most Stakeholders Support Special Interconnection Rules for Tribes

By James Downing

Most stakeholders support a proposal before FERC to exempt energy projects developed by federally recognized Native American tribes from deposits and other fees in the generator interconnection process.

The Alliance for Tribal Clean Energy filed a petition for an expedited rulemaking to exempt tribal energy projects from fees designed to discourage speculative development, which won widespread support in comments filed ahead of a Nov. 18 deadline (RM24-9). (See *FERC to Consider Special Interconnection Rules for Tribal Energy Projects*.)

Tribes and their representatives from around the country were supportive of the policy, arguing that commercial readiness deposits and withdrawal penalties, which are meant to discourage speculative projects, do not make sense for the developments that tribal entities pursue.

The Inflation Reduction Act effectively opened up tax credits for tribal energy projects, but some of FERC's rules still offer regulatory barriers to that development, said the Midwest Tribal Energy Resources Association, which represents 27 tribes from the region.

"We have witnessed firsthand the unique challenges tribes face due to current regulations that require commercial readiness deposits and impose withdrawal penalties," the association said. "These requirements, while intended to manage speculative interconnection requests, disproportionately impact tribal nations who often lack access to the same financial resources and capital as traditional energy developers."

The Navajo Transitional Energy Co. (NTEC) is a Tribal Energy Development Organization (TEDO) owned by the Navajo Nation, which controls 17 million acres of "trust lands" in the Four Corners area in the Southwest and includes 300,000 members, including 170,000 at the reservation. NTEC owns the Navajo Mine, which serves the Four Corners Generating Station, a 1,540-MW coal plant in which it owns a 7% stake with plans to add a carbon capture and storage demonstration project to the site.

NTEC is also pursuing renewable energy projects, including a 1,200-MW solar plant that will be built in several stages with ENGIE North America.

"The federal government has recognized it has a trust responsibility to protect tribal sovereignty, economic security and Tribal Energy Development Organizations' energy development on tribal lands," NTEC said. The commission has, likewise, stated it endeavors to "work with the tribes on a government-to-government basis."

TEDOs have historically been structurally excluded from capital markets and are unable to use traditional tax equity or debt financing, NTEC said. "Instead of traditional financing available to other transmission developers, Tribal Energy Development Organizations secure much of their financing through philanthropy and federal grants only available once a project has secured interconnection rights."

The sovereign nature of tribes can discourage private parties from entering into contracts with them, but they have land with often good resources to develop.

"Land, without an interconnection, cannot support a generating facility," NTEC said. "The commission can make tribal energy development more attractive to development partners by modifying the *pro forma* interconnection procedures to increase Tribal Energy Development Organizations' chances of being able to offer a favorable position in the interconnection queue."

Four Corners Generating Station | *Energy and Policy Institute*

Why This Matters

Tribal lands are home to some of the best energy resources in the country, but on average, they pay some of the highest energy rates. And while the Inflation Reduction Act effectively opened up tax credits for tribal energy projects, some of FERC's rules still offer regulatory barriers to development.

The Environmental Defense Fund, National Wildlife Federation, Earthjustice, Natural Resources Defense Council, Sustainable FERC Project and Center for Biological Diversity filed joint comments in support of the petition. They said the process leading to Order 2023 involved insufficient input from federally recognized tribes and that led to a rulemaking that does not work for them, which is a potential violation of FERC's "trust responsibility" to tribes.

"The United States government holds a trust responsibility toward tribes, rooted in Article I, Section 8 of the Constitution, shaped and defined by 375 treaties, hundreds of laws and countless executive orders," the groups said. "This fiduciary duty requires the government to honor treaty obligations, manage resources for tribes' benefit and act in their best interests. Federal agencies are mandated to actively consult and engage with tribes on matters impacting tribal lands, resources and cultural heritage, ensuring respect for tribal sovereignty and upholding commitments to promote tribal self-determination and wellbeing."

Energy projects developed by tribes are not speculative because tribes always have direct control of the land and limited points of interconnection, which means they cannot file speculative projects in search of the best one,

Continued on page 9

FERC/Federal News

NERC Files ITCS to FERC, Meeting Congress' Deadline

Additional Canada-focused Installment to Come in 2025

By Holden Mann

NERC has filed the *final draft* of the Interregional Transfer Capability Study (ITCS) with FERC, wrapping up the ERO's portion of the task set out by Congress in the *Fiscal Responsibility Act of 2023* ahead of the December deadline.

The ERO submitted the ITCS on Nov. 19, NERC Director of Reliability Assessments and Performance Analysis John Moura said in a webinar the same day. Next, FERC will post the report for a public comment period; Moura said the starting date and duration of the comment period have not been set.

Following the comment period the commission will submit recommendations for statutory changes, if any, to Congress.

Submitting the ITCS is a "milestone in our ongoing efforts to enhance reliability across" the continent's electric grid, Moura said. The FRA, passed in June 2023, ordered NERC to work "in consultation with" the regional entities and transmitting utilities to submit the study to FERC by December 2024, leaving the ERO less than 18 months to complete an unprecedented task.

Using a favorite comparison, Moura reminded listeners that "Congress has only asked NERC and the ERO to do two things in our entire history: form ourselves back in 2005 under the … Energy Policy Act, but also to do this study." As a result, he said, NERC saw ITCS as "on par in terms of importance with its own charter.

John Moura, NERC | *NERC*

The study comprises three parts, aligning with each major objective set by Congress. *Part 1*, released in August in draft form, contained an analysis of transfer capabilities between transmission planning regions in North America. The *second and third parts* were released earlier in November; they provide, respectively, recommendations for prudent additions to transfer capability that could strengthen grid reliability and recommendations to meet and maintain total transfer capability. (See *NERC Releases Final ITCS Draft Installments*.)

While these components focus on the U.S. grid, Moura said NERC concluded early on that "you really cannot have a credible study without including Canada." Now that the congressional mandate has been achieved, the ERO will complete an additional installment covering transfer capabilities and prudent additions from the U.S. to Canada and between Canadian provinces. NERC plans to release the fourth installment in the first quarter of 2025.

Meeting the FRA's requirements posed considerable challenges for NERC, Moura said. To start with, while the ERO previously conducted regional studies of transfer capability, it never had attempted to do so across the entire grid and never incorporated the efforts of transmission utilities to this extent. The congressional mandate provided NERC with an opportunity to stretch itself and build capabilities for collaboration that will be useful in future studies, Moura said.

Another difficulty was defining the scope of the study. The FRA described its goals in broad terms but, as Moura explained, narrowing the requirements to a workable framework took some effort.

"We didn't find 'prudent' in our engineering textbooks, so we really had to understand, what is Congress asking us?" Moura said. "The way NERC thinks about 'prudent' is really laser-focused around reliability. And so prudent for reliability is what this study is all about. We don't look at economics, we don't look at cost-benefit between different projects or different approaches. We're strictly looking at this challenge from a reliability perspective and remediating the reliability impacts that we see out into the future." ■

Most Stakeholders Support Special Interconnection Rules for Tribes

Continued from page 8

the environmentalists said. Tribal lands on average have 70% fewer kilometers of transmission and 43% less high-voltage transmission than the rural U.S.

The environmentalists agreed that tribes often face issues with financing in part because lenders are unfamiliar with their legal systems, their lands have little pre-existing infrastructure, and it is hard to secure financing.

"Much of tribal land is held in trust by the federal government, restricting lenders' ability to claim an interest in land as collateral if a borrower defaults," they added.

The Choctaw Nation of Oklahoma urged FERC to also give deference to tribes when they oppose jurisdictional energy projects being built on their lands.

"These projects provide benefits to non-tribal entities while imposing most of their costs on the tribal nations, which is the definition of environmental injustice," the tribe said. "The proposed Pushmataha County Pumped Storage Project is a textbook example of this."

The tribe was referring to a project proposed by Southeast Oklahoma Power Corp. on lands and waters within the Choctaw reservation that derive profit by generating electricity to be sold to Texas (*P-14890*). Despite opposition from the Choctaw and Chickasaw Nation, it is moving forward.

While most of the intervenors in FERC's docket were supportive of the petition, it did run into opposition from Idaho Attorney General Raúl Labrador (R).

"Instead of following the same requirements as everyone else, the tribes would get a blanket waiver from paying commercial readiness deposits at the same time as other requesters and from paying the full withdrawal penalties," he said. "This exception would give the tribes an easier path to connecting their generators to the grid, giving them an unfair advantage." ■

CAISO/West News

4 Arizona Utilities Commit to Joining Markets+

Announcements Represent 1st Public Commitments for SPP's Western Market

By Elaine Goodman

Four Arizona utilities announced their plans to join SPP's Markets+ day-ahead market, a significant win for SPP after a string of victories for CAISO's competing Extended Day-Ahead Market (EDAM).

Arizona Public Service (APS), Salt River Project (SRP), Tucson Electric Power (TEP) and UniSource Energy Services made the announcement Nov. 25.

Markets+ is expected to save the utilities nearly $100 million while enhancing reliability and supporting the addition of renewable resources to the grid, the utilities said in a *joint release*.

The utilities said they plan to begin Markets+ participation as soon as 2027.

"Together with our neighboring utilities, APS plans to join Markets+ to efficiently deliver energy and bolster the resilience of our shared energy grid in Arizona and across the region," Brian Cole, APS vice president of resource management, said in a statement.

When asked about the reasons for choosing Markets+ rather than CAISO's EDAM, an SRP spokesperson said the primary drivers are governance and resource adequacy.

The Markets+ governance structure promotes independence, transparency, inclusivity and stakeholder-driven decision-making, the spokesperson said.

And Markets+ will adhere to a single, shared resource adequacy program — the Western Resource Adequacy Program — providing a consistent method to make sure enough resources are available to reliably serve load across the Markets+ footprint.

"It also ensures that all market participants contribute fairly to the reliability of the market footprint, preventing any participants from systemically leaning on others," the SRP spokesperson said.

Salt River Project's Theodore Roosevelt Dam. The publicly owned utility was among four Arizona utilities to commit to joining SPP's Markets+. | *Salt River Project*

Why This Matters

The announcement by the Arizona utilities finally puts SPP's Markets+ on the map in its competition with CAISO's EDAM and could help sway some decisions in the Northwest.

SRP expects a critical mass of entities joining Markets+ in spring 2027, and SRP will sign an implementation agreement before the market goes live.

Tariff Decision Pending

The announcement comes as SPP awaits FERC's decision on the Markets+ tariff, which was initially filed in March. FERC issued a deficiency letter in July identifying 16 problems in the tariff. (See *FERC Finds SPP Markets+ Tariff 'Deficient' in Several Areas*.)

SPP filed a response to the letter in September, addressing each issue and asking FERC to issue an order by Nov. 20.

But FERC isn't required to abide by that request and will take "as much time as they need," an SPP spokesperson told *RTO Insider*. SPP said previously it's confident it can address concerns the deficiency letter raised.

In contrast, CAISO's EDAM has already received FERC approval.

A TEP spokesperson said the company fully expects FERC to approve the Markets+ tariff, while acknowledging the approval can be an "iterative process," a comment echoed by SRP.

"We will continue to work with FERC and SPP throughout the process in demonstrating the value this direction will bring to our customers," the TEP spokesperson said.

FERC approval of the tariff will mark the start of a second phase of Markets+ development.

"SPP thanks all Markets+ stakeholders for their engagement and collaboration in phase one development and looks forward to their continued involvement," Antoine Lucas, SPP vice president of markets, said in a statement provided to *RTO Insider*. "We eagerly anticipate receiving signed phase two commitments by the end of the year so we can continue to

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work together to build a market that provides benefits for all western entities."

Footprints Taking Shape

The Arizona utilities' announcement of their Markets+ decision is the latest step in the evolution of two day-ahead market footprints in the West. In addition to the Arizona announcement, Bonneville Power Administration has expressed a "leaning" toward Markets+ over CAISO's EDAM. BPA is waiting for FERC's ruling on the Markets+ tariff before deciding. (See *BPA Execs Lay out Markets+ Benefits, Risks, Reasons*.)

Although Powerex has not yet made a formal commitment to a day-ahead market, it has clearly signaled an intention to join Markets+ and not EDAM.

The Arizona announcement "is a clear indication of the value that many utilities are seeing in the Markets+ day-ahead market option," Lauren Tenney Denison, director of market policy and grid strategy at the Public Power Council (PPC), said in an email to *RTO Insider*.

The Portland-based PPC, a trade group representing the extensive network of Northwest publicly owned utilities that buy low-cost power from the Bonneville Power Administration, has been a consistent advocate of BPA choosing Markets+ over CAISO's EDAM. (See *Northwest Public Power Group Endorses Markets+ over EDAM*.)

"As a participant in the development of Markets+, PPC has appreciated the collaboration we have had with these Arizona utilities and the shared goals we have for a well-designed, well-governed day ahead market option," Tenney Denison said.

Meanwhile, EDAM scored its latest win this month with Public Service Company of New Mexico's announcement of its plans to join the CAISO market. (See *PNM Picks CAISO's EDAM*.)

PacifiCorp, Portland General Electric and Balancing Authority of Northern California have signed EDAM implementation agreements with CAISO and the list of entities expected to join EDAM has grown to include NV Energy, Idaho Power and Los Angeles Department of Water and Power.

In October, the Western Area Power Administration's Desert Southwest (DSW) Region said it would cooperate with Arizona G&T Cooperatives on a study examining the potential benefits of DSW joining EDAM. DSW this year withdrew from the second phase of developing Markets+ after determining it would realize few benefits from participating in that market. (See *Arizona G&T Cooperatives Announces Pursuit of EDAM Benefits Study*.)

After NV Energy announced its intent in May to join EDAM, Advanced Energy United issued a statement encouraging other entities, especially those in the Southwest, to join EDAM. The industry association said EDAM was becoming "the most viable day-ahead market."

Brian Turner, who leads Advanced Energy United's regulatory engagement in the West, said AEU is pleased that Arizona utilities are "embracing broader energy markets," which have the potential to bring customer benefits including greater reliability and affordability.

But Turner said the Arizona announcement is "bittersweet," as having two Western day-ahead markets will create seams and market inefficiencies.

As the market footprints are now developing, Markets+ could end up with a "big fat seam" in Northwest-Southwest trade caused by NV Energy and California entities joining EDAM, Turner said in an interview.

And the Arizona utilities are giving up known benefits of their participation in CAISO's Western Energy Imbalance Market (WEIM) in exchange for unknown potential benefits of Markets+, he added.

But how the Western day-ahead markets ultimately take shape remains to be seen.

"Things are still very dynamic," Turner said. ■

Robert Mullin contributed to this article.

CAISO/West News

Amid Praise for Pathways Step 2 Milestone, Skeptics Remain Unmoved

Approval of Plan to Establish 'RO' Unlikely to Shift Market Competition Dynamics

By Robert Mullin

The West-Wide Governance Pathways Initiative drew praise from many quarters Nov. 22 when its Launch Committee voted to approve its "Step 2" proposal to create an independent "regional organization" to oversee CAISO's Western electricity markets.

But it was quickly apparent the development — over a year in the making — is unlikely to shift views of those entities that remain skeptical about joining a market operated by CAISO and instead favor SPP's Markets+. (See related story *Pathways Initiative Approves 'Step 2' Plan, Wins $1M in Federal Funding*.)

Counted among the strongest supporters of the final proposal, which was released Nov. 15, were the state utility regulators and energy officials largely responsible for launching the Pathways Initiative in July 2023.

"It was only last summer that my colleagues and I across the West wrote a letter expressing our hope for an independent regional organization to oversee an expanded day-ahead market that includes California," California Energy Commission Vice Chair Siva Gunda said ahead of the Launch Committee's vote. "Since then, it's amazing to watch how some of the brightest and most dedicated experts across diverse sectors in the West have come together to lay the foundations for this regional organization."

"The Launch Committee, the stakeholders — you stepped up to the request in the letter, working together, had success for [Pathways] Step 1, and [are] now voting on this foundational document that could really achieve the broad idea that was in our request," New Mexico Public Regulation Commission Chair Pat O'Connell said.

Oregon Public Utility Commissioner Letha

Why This Matters

While recognizing the significant amount of work that went into the Phase 2 proposal, BPA and other critics say the plan falls short of providing fully independent market governance, administration and operations.

Kathleen Staks, Western Freedom | © RTO Insider LLC

Tawney said she appreciates the proposal "centers consumers" and provides "the opportunity for benefits in a different way that is exciting."

"At the end of the day, we have to be delivering for consumers this essential service at a price they can manage," Tawney said. "That is what underpins the Western economy, but it also is what delivers for our most vulnerable customers, and I so appreciate the Launch Committee digging in and figuring out how to deliver on that fiduciary duty that the regulators put out to the region and asked you to help us solve."

Michele Beck, director of the Utah Office of Consumer Services and a Launch Committee member, said she began participating in the Pathways effort "defensively," which is how she thinks consumer advocates likely approach any such regional activities.

"Working with this group helped me to build confidence in the effort and really optimism about the outcome, as I saw a genuine focus on the public interest, which has been mentioned before. I think our proposal really has the greatest public interest protections that we see in any regional proposals out there," Beck said.

Beck acknowledged that Pathways still has a lot of work ahead of it in the next year and that Step 2 did not address some "big issues" that "were properly" not within its scope.

"But this is consistent with the incremental approach that we've been taking here in the West, and [Step 2] remains a very important milestone," she said.

Committee member Brian Turner, director of Advanced Energy United's regulatory engagement in the West, said the Step 2 "proposed governance structure recognizes the electric grid is evolving and a greater diversity of resources and customers and load-serving entities and solution-providers all have an essential interest in efficient markets and the affordability and reliability they bring."

Nonvoting committee member Chrystal Dean, vice president of enterprise portfolio management at the Western Area Power Administration (WAPA), noted that WAPA's Sierra Nevada region recently announced it will begin negotiations toward full participation in EDAM through its membership in the Balancing Authority of Northern California and that its Desert Southwest (DSW) region will partner with Arizona G&T Cooperatives on a study to assess the CAISO market's benefits for the

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DSW balancing authority area. (See *WAPA Sierra Nevada Region to Advance with EDAM* and *Arizona G&T Cooperatives Announces Pursuit of EDAM Benefits Study*.)

"Both of these efforts underscore WAPA's commitment to exploring new opportunities like those described in this Pathways Step 2 proposal, and we are really excited to see that these steps will help WAPA continue to make decisions that align with our market principles," Dean said.

Committee co-Chair Kathleen Staks, executive director of Western Freedom, said that as a representative of commercial and industrial electricity customers, she's seen a "remarkable increase in the number of companies that are actively engaged and paying attention and wanting to learn, and so I think they are. We're seeing a sector that's getting very excited about the opportunities to participate."

'No Guarantee'

But the Pathways milestone failed to dispel skepticism about the effort from entities still firmly situated in the Markets+ camp.

Britney Morgan of Arizona Public Service, the sole committee member to abstain from voting on the proposal, said while Step 2 would incrementally improve the independence of the governance of CAISO's WEIM/EDAM, it "does not achieve independent governance, which was the ask of the regulars more than a year ago."

"Under Step 2, ... CAISO remains as the market operator, which perpetuates existing inequities between market and state participants," Morgan said.

Rachel Dibble, vice president of bulk power marketing at the Bonneville Power Administration, acknowledged "the significant amount of work" the Launch Committee and work group put into the Phase 2 proposal but said the plan fell short of BPA's expectation for fully independent market governance, administration and operations for CAISO's markets.

Dibble reiterated three concerns BPA has recently expressed about the proposal: that it will 1) leave the RO under a single, integrated tariff shared with CAISO; 2) leave market operations, supporting staff and management functions under CAISO board authority; and 3) maintain the ISO as the counterparty in contracts with market participants.

In an email to *RTO Insider*, Lauren Tenney Denison, director of market policy and grid strategy at the Portland-based Public Power Council (PPC), voiced a view that aligns with BPA's.

"Individual PPC members will evaluate the risks and benefits of this proposal in making their market participation decisions," Tenney Denison wrote. "That said, for PPC and most of our members, the Step 2 proposal advanced by the Launch Committee falls well short of our expectations for independent governance. The limited creation of a 'policy setting' organization that continues to rely heavily on CAISO in many areas — financial, regulatory and staffing, for instance — will *not* establish a regional organization or market administrator that is independent. While potential future evolution is possible, there is no guarantee this will occur." ■

CAISO/West News

Pathways Initiative Approves 'Step 2' Plan, Wins $1M in Federal Funding

Award Should Provide Big Boost for Effort to Establish a Western 'Regional Organization'

By Robert Mullin

The West-Wide Governance Pathways Initiative's Launch Committee voted Nov. 22 to approve the group's "Step 2" proposal to create a new Western "regional organization" (RO) to provide independent oversight for CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM).

The proposal passed on a nearly unanimous vote, with one abstention by committee member Britney Morgan, a regulatory consultant with Arizona Public Service, who said that while the utility agreed the plan represented "incremental" progress toward the goal of bringing independent governance to CAISO's markets, it did not meet the utility's standard for independence.

APS has been a funder and strong supporter of SPP's Markets+, which is competing with EDAM for participants.

Other committee members were effusive in their praise for the proposal, with some citing incrementalism as beneficial for a Western region that has been historically suspicious of developing a centralized market, while others noted the "diversity" of interests that came together to develop the plan.

"Because the proposal creates a Western entity staffed by Western people, we strongly support this proposal as the best option for all of us," said committee member Ben Otto, speaking on behalf of the Northwest Energy Coalition, an ardent EDAM supporter.

The vote came two days after Pathways received a significant financial boost from the U.S. Department of Energy, which awarded nearly $1 million to underwrite its efforts to establish the RO.

The award was issued through Pathways' philanthropy adviser, Global Impact. The Launch Committee partnered with the nonprofit early this year to secure outside funding for its operations, which so far have been supported by donations — and volunteer staff — from its participants.

The award was part of nearly $10 million that the administration *granted* to six projects nationwide intended "to improve state and regional engagement in wholesale electricity markets."

An *abstract* of the application that Global Impact submitted to the DOE's Grid Deployment Office shows Pathways applied for $985,109 over two years to "support stakeholder convening, materials development, facilitation and personnel costs to achieve the goals of Phase 3 of the initiative," which will include "refinement and formalization" of the RO's stakeholder process, creation of "final governance documents and tariff language" for the RO, and identifying and hiring of the RO's board and initial staff.

The Launch Committee met Nov. 22 to vote on the Step 2 proposal. | © RTO Insider LLC

Why This Matters

The money from the Biden administration should go a long way to help fund the Pathways Initiative's 'Step 2' effort to establish a Western 'RO.'

The most recent spreadsheet posted on the Pathways website in August shows that six organizations have committed to fund the second and third phases of the effort, including the Clean Energy Buyers Association, California Community Choice Association, Balancing Authority of Northern California, Western Freedom, Microsoft and Amazon.

The Step 2 proposal, released Nov. 15, said the RO, to be established next year, would start out with "limited staffing" on an estimated budget of $1.25 million to $1.5 million, which eventually could increase to $10 million to $14 million. (See *Pathways Initiative Issues Final 'Step 2' Proposal*.)

The proposal also said the committee recognized that start-up funding for the RO likely will "be required before any market-supported funding is available" and that due consideration "should be given to identifying funding that would not be considered as compromising [RO] board independence."

"The recommendation is to consider sources such as DOE grant funding or ongoing support from the Pathways Initiative 501(c)(3) funding via Global Impact," the Launch Committee wrote in the proposal. "There was little stakeholder comment on this recommendation, though general support existed."

The award represents a sharp turnaround for Pathways, which earlier this year was rejected for $800,000 in DOE grants because the department said it lacked details about the scope of activities to be covered by the funding, which would have been dispersed in $400,000 tranches over two years. (See *Pathways Initiative Rejected for $800K in DOE Funding* and *Past Opponents Now See Legislative Pathway to CAISO Regionalization*.) ■

CAISO/West News

Powerex to Cancel Rights on PacifiCorp Tx System over EDAM Changes

Company Says the Utility is Putting $135M at Risk with Proposed OATT Changes

By Henrik Nilsson

Powerex intends to terminate a large portion of its rights on PacifiCorp's transmission system in response to the utility's plan to update its Open Access Transmission Tariff to align with CAISO's Extended Day Ahead Market (EDAM), the company said in a Nov. 14 paper that also warned the changes could cost the utility about $135 million in revenue.

Powerex argued in the *paper* that PacifiCorp's expected tariff changes could lead to the utility using EDAM's rules related to the distribution of transmission congestion rents to "effectively strip" its transmission customers of "the economic value of their transmission rights" — to the detriment of customers in both EDAM and SPP's Markets+.

"Unfortunately, PacifiCorp has chosen to use its entry into EDAM to fundamentally redefine what it provides to its transmission customers in exchange for the transmission revenue it collects," wrote Powerex, the energy marketing arm of Vancouver, Canada-based BC Hydro.

The company's contention potentially opens up yet another front in ongoing competition between EDAM and Markets+ and in the debates between each market's supporters.

PacifiCorp's plans have already led to Powerex providing a notice "to terminate the vast majority of Powerex's long-term firm point-to-point transmission rights on PacifiCorp's transmission system, for which Powerex currently pays over $42 million per year to PacifiCorp," according to the paper.

However, despite the move to cancel the contracts, Powerex emphasized it will retain 200 MW of rights to ensure power flows in SPP's Markets+ — a position it intends to fight for before FERC.

Jeff Spires, director of power at Powerex, told *RTO Insider* in an email that the company "continues to hold the long-term firm transmission rights it intends to use for Markets+ connectivity, and is committed to protecting these rights on the PacifiCorp system."

Under PacifiCorp's anticipated changes, transmission customers will face new congestion charges calculated in EDAM, collected in CAISO and delivered to PacifiCorp, according to Powerex. The congestion charges will not be returned to customers but rather spread across all of PacifiCorp's load and exports, the paper stated.

"As a result, transmission customers that wish to use their rights to schedule physical deliveries outside of organized markets will not receive the economic value of the path they invested in, but will instead face volatile and potentially large EDAM congestion charges that they cannot manage or hedge," Powerex argued. "Similarly, customers that wish to use their firm transmission rights in Markets+ will also not receive the economic value of the path they invested in, as they too will face these EDAM congestion charges (that are again allocated largely to PacifiCorp)."

Transmission customers will be forced to sell their transmission rights to CAISO for use in EDAM to continue receiving congestion value associated with their delivery path, Powerex contended.

PacifiCorp could lose out on $135 million per year from its sale of point-to-point service to unaffiliated transmission customers, as the proposal will reduce the incentives to invest in the company's firm transmission service, Powerex alleges.

"Any loss of third-party transmission revenue resulting from PacifiCorp's proposal will directly increase the revenue that PacifiCorp must recover through higher retail rates," the paper stated. This loss in revenue has not been considered in any EDAM benefit study, according to Powerex.

Clarity Needed at Market Seam

Additionally, Powerex urged Portland General, NV Energy, Idaho Power and LADWP, among others, to "consider whether to follow PacifiCorp's lead and jeopardize their existing transmission revenue stream, or to instead seek ways to continue to provide the core benefits that are the foundation for transmission customers' investments in long-term firm transmission service."

The tariff changes highlight the absence of a governance structure in EDAM that protects transmission rights "in an equitable and consistent manner," according to the paper.

When asked to comment on Powerex's paper, a PacifiCorp spokesperson told *RTO Insider* that "[i]n developing its tariff for participation in EDAM, PacifiCorp has taken the view that addressing transmission usage for other markets is premature at this stage since market to market coordination requires larger discussions with stakeholders that can only occur in the context of developed and approved market designs. Once the issues at market seams become clearer, PacifiCorp will work with stakeholders and relevant parties to address those issues."

Why This Matters

Powerex's contention regarding PacifiCorp's tariff change could open up a new front in the increasingly contentious debate between EDAM and Markets+ supporters.

Portland, Ore.-based PacifiCorp, whose sprawling territory includes portions of six states, was the first utility to join CAISO's Western Energy Imbalance Market in 2014 and the first to publicly announce its intent to join EDAM in December 2022.

The company fully committed to joining EDAM in April. (See *PacifiCorp Fully Commits to CAISO's EDAM*.)

Cindy Crane, CEO of PacifiCorp, recently touted the benefits of EDAM during CAISO's Stakeholder Symposium in October, citing CAISO data showing $6 billion in member benefits from the WEIM since its inception and $1.4 billion in benefits in a fully implemented EDAM. (See *Western Utility CEOs Reflect on Evolving Energy Markets*.)

However, SPP's plan to launch Markets+ has gathered momentum over the past two years and has garnered support from powerful backers such as the Bonneville Power Administration and Powerex.

In the competition for participants between the two markets, Markets+ supporters have consistently pointed to the market's independent governance structure and market design established under that governance. (See *BPA Execs Lay out Markets+ Benefits, Risks, Reasons*.)

Powerex's recent paper continued to push that argument while also claiming that EDAM benefits studies have failed to consider potential revenue losses if PacifiCorp's transmission tariff proposal should pass. ■

CAISO Kicks off 'Workshop' to Update RA Mechanisms

New Initiative Addresses RA Showings, Incentive Mechanisms, Counting Rules, Backstop

By Ayla Burnett

CAISO on Nov. 18 kicked off a Resource Adequacy Modeling and Design "workshop" designed to reevaluate and refine several mechanisms the ISO uses to ensure resource adequacy.

The workshop builds on the ISO's *RA Modeling and Program Design working group*, in which staff and ISO stakeholders highlighted problem statements associated with the RA program. It aims to continue refining solutions to the problems identified and develop policy responses.

The main goal of the effort is to update the default counting rules and planning reserve margin (PRM), evaluate the need for the Resource Adequacy Availability Incentive Mechanism (RAAIM) or an unforced capacity mechanism (UCAP), and reevaluate outage and substitution rules and the capacity procurement mechanism (CPM), also referred to as the "backstop."

The issues will be addressed in the three different tracks, but ISO staff noted the tracks can be combined or changed based on stakeholder feedback.

Track one addresses modeling, default rules and accreditation, while track two deals with outage substitution and availability and performance incentive mechanisms. Track three tackles visibility and backstop.

The workshop will be further divided into three "packages" that outline workflow. Package one identifies minimal changes needed to take the first step in addressing the topic, package two outlines forward planning and package three covers operational measures.

The packages are "illustrative" and not representative of CAISO's preferred or final approach, said Partha Malvadkar, principal of RA and infrastructure policy at the ISO.

Why This Matters

The new effort is intended to help CAISO address an issue facing RTOs and ISOs across the country: how to ensure and fairly account for resource capacity.

"What we're looking for as we work towards policy development is packages of changes that make sense together and that are achieving the goals and objectives that came out of the working group process in a comprehensive and consistent manner," Malvadkar said.

PRM and Default Counting Rules

Another central aim of the initiative is to evaluate how well PRMs and counting rules set by local regulatory authorities (LRAs) reflect forced outage rates, performance and availability. Evaluating the need for UCAP, which was discussed in the prior initiative, fits into this area. (See *CAISO Considers Replacement of RA Incentive Program*.)

"In response to potentially changing regulatory structures at the CPUC (including the scoping of UCAP), CAISO has an opportunity to establish alternatives to the current resource counting design and eliminate/redefine availability and performance incentives while acknowledging LRA authority to establish counting rules," according to a presentation from the meeting.

The ISO also identified the need to update the PRM based on changes in the RA resource mix and evolving reliability needs within the CAISO balancing authority area (BAA). CAISO policy developer Ansel Lundberg identified that qualifying capacity values, also referred to as "counting rules," should reflect the relative contribution of different resource types to maintain BAA-wide and local reliability and to meet at least a 0.1 LOLE.

The initiative also addresses the need for capability testing to account for seasonal resource availability. According to Lundberg, the availability of resources based on varying seasonal ambient derates is not consistently reflected in resource net qualifying capacity (NQC), which poses challenges for grid operations. CAISO thinks it should adopt minimum requirements so it can rely on capacity to perform consistent with accreditation in a given season. Such requirements could minimize partial forced outages that derate resources below their NQC value during critical periods.

Outages and Substitution

CAISO also intends to work to establish a more efficient process for outages and substitution. Central to that is developing a voluntary planned outage substitution pool, where scheduling coordinators can make capacity available and pay for it if needed. SCs could also procure from the pool.

The ISO is also considering developing a planned outage buffer provided by each LRA, as well as moving to annual or seasonal showings, CAISO lead policy developer Anja Gilbert said.

The final intent of this track is to remove planned outage substitution requirements and replace them with strong incentives and better information about periods of risk.

RAAIM Reform

RAAIM is one such incentive mechanism that could help remove planned outage substitution requirements. But the ISO is considering revising RAAIM to become a "pay-for-performance" mechanism for capacity to respond and non-capacity resources to be available during scarcity conditions.

That model, which has been implemented in PJM and ISO-NE, acts as both a reward and penalty relative to a resource's obligation during scarcity events. If a supplier's poor performance contributes to reliability risk, it could face "strong consequences," according to Lundberg's presentation.

Backstop and Visibility

A central component of the prior and current RA initiatives within the ISO is the need for more visibility into RA and non-RA resources. (See CAISO*'s Capacity Procurement Mechanism Inefficient, Stakeholders Say*.) CAISO's lack of visibility into the "not-shown" RA fleet makes the backstop mechanism less efficient, but regular reporting on the status of RA capacity could improve the system, said CAISO lead policy develop Hilary Staver.

The ISO suggested options for policy reform, including updating CPM authority to accommodate the backstop based on an assessment of energy sufficiency and/or net peak needs.

"We're looking to provide visibility into RA and non-RA resources in order to allow for efficient decision making in CAISO operations, obtaining capacity with the right attributes when and where it's needed, and trying to be efficient and effective in our backstop approach," Staver said. ■

ERCOT News

ERCOT to Recommend RMR Agreement for Braunig

Grid Operator Briefs Texas PUC, Which Takes Action on Crypto, Beryl Investigation

By Tom Kleckner

ERCOT says it will recommend that its Board of Directors approve a reliability-must-run (RMR) contract for one of three aging CPS Energy gas units, set for retirement, to maintain reliability in the San Antonio area.

The grid operator also told the Texas Public Utility Commission during its Nov. 21 open meeting that it is working with CPS and CenterPoint Energy to determine whether the latter's controversial $800 million mobile generators could be moved to San Antonio as an alternative.

"I think this is an elegant solution to a number of issues that we're facing," PUC Chair Thomas Gleeson said in response.

CenterPoint's 2021 lease of 15 32-MW generators and 13 smaller ones (between 1.2 and 5 MW) became a source of *derision and political criticism* when they went largely unused during the utility's weekslong restoration after Hurricane Beryl. (See *Texas Politicos, Residents Bash CenterPoint*.)

ERCOT General Counsel Chad Seely told the PUC that grid operator staff, the two utilities and Life Cycle Power, the generators' owner and operator, have been discussing moving the larger units and their 480 MW of capacity to the San Antonio area. He said the 15 large generators are the equivalent of two of the retiring plants, Braunig Power Station's Units 1 and 2, and would provide greater reliability than CPS' forced outage-prone assets.

That comes from "mainly the diversity of where those units can be located versus having two larger units that have the susceptibility of higher forced outages," he said. "These are dual-fuel-capable units. They could be located in San Antonio with a higher shift factor. And obviously their start time is about 10 to 15 minutes, versus a longer lead time for Units 1 and 2."

Why This Matters

ERCOT is recommending its first reliability-must-run contract since 2016 to address reliability needs in the San Antonio area. Transmission projects currently underway will eventually solve the problems.

ERCOT's Chad Seely explains plans to resolve reliability issues in the San Antonio area. | *Admin Monitor*

CenterPoint said in an emailed statement that its "top priority is finding a Texas-driven solution that helps address the growing energy needs of Texans and our strong economy."

"We are optimistic that we will find a constructive solution that best serves our customers and Texas," the utility said.

San Antonio's municipal utility told ERCOT earlier this year that it planned to retire the three Braunig units, which date back to the 1960s, in March 2025. However, ERCOT said the resources, with a combined summer seasonal net maximum sustainable rating of 859 MW, were needed for reliability reasons and *issued a request* for RMR proposals in July. (See *ERCOT, CPS Energy Negotiating RMR, MRA Options for Retiring Units*.)

In the meantime, Seely said ERCOT will urge its board to approve an RMR agreement for Braunig Unit 3, the newest (1970) and largest (412-MW maximum summer rating) of the three units. It will ask the directors to defer any decision on the other two units so staff can continue to work on the feasibility of the mobile generators' move. The board meets Dec. 2-3.

CPS has said each unit must be inspected and repaired — consecutively, not concurrently — if it is to operate beyond its retirement date. The utility has moved the unit's suspension date up to March 2, allowing time for inspection and repairs that it says will take at least 60 days.

"If the board moves forward with an RMR agreement, that will allow us to move forward with that inspection work at the beginning of March in trying to get that unit back for the summer of 2025," Seely said. "A lot of work has been done on the technical side. We do believe it is technically feasible to move those 15 units into the San Antonio area."

"There are many factors being evaluated by ERCOT and the companies involved," CPS spokesperson Miguel Vargas told *RTO Insider* in an email. "We remain engaged in ERCOT's efforts to evaluate this alternative proposal."

ERCOT says the RMR units will be important in addressing the South Texas export interconnection reliability operating limits staff established this year that will eventually be resolved by transmission projects underway. Their analysis revealed that under certain conditions, such as when high system demand coincides with an outage of a major transmission line or one or more generation units, lines that deliver power from South Texas into San

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ERCOT News

Texas PUC's Cobos to Leave Commission

By Tom Kleckner

Texas Public Utility Commissioner Lori Cobos announced Nov. 21 that she plans to step down from the commission at the end of 2024.

Cobos told her fellow commissioners, PUC staff and stakeholders that she already had shared her plans with Gov. Greg Abbott. She promised a much broader statement during the commission's last open meeting of the year, Dec. 19.

"It has been a tremendous honor and a privilege to serve as a PUC commissioner," Cobos said. "I want to thank the governor for the opportunity of a lifetime and for placing his trust in me to serve on the commission after Winter Storm Uri. I'll say a lot more later ... we've accomplished an extensive list of important milestones at the commission over the last several years, and I am proud and tremendously grateful to have been part of that amazing work."

Cobos has played a leading role in the development of major transmission infrastructure projects, including in the Permian Basin region in West Texas and in the Rio Grande Valley. (See *Texas PUC Approves Permian Reliability Plan*.)

She was one of the three commissioners named to replace the PUC's incumbents, all of whom left the commission after the devastating February 2021 winter storm that came within minutes of collapsing the ERCOT grid. Cobos joined Peter Lake, who chaired the commission, and Will McAdams. Both left the PUC in 2023.

The commission since has been expanded by state law to five members.

"Like I told Peter and Will when they were leaving, 'Thank you for being willing to say: yes.' These were not jobs that people were falling all over themselves to come take right after Winter Storm Uri," commission Chair Thomas Gleeson told Cobos. "It took a special kind of person with the heart of a public servant to want to come and do this right after the storm. You will be missed up here."

Abbott appointed Cobos to the PUC in June 2021. Her term expired that September but by law, she did not have to be reappointed and has continued to serve at the governor's pleasure. (See *Abbott Taps OPUC's Cobos to Fill out PUC*.)

Cobos has more than 20 years of experience in the Texas power industry, including several senior-level positions at the PUC and in-house counsel at ERCOT. She joined the commission after being appointed as CEO and public counsel for the Office of Public Utility Counsel.

Cobos is an ex officio member of the ERCOT Board of Directors and serves on SPP's Regional State Committee. She also is president of the Southeastern Association of Regulatory Utility Commissioners. ■

ERCOT to Recommend RMR Agreement for Braunig

Grid Operator Briefs Texas PUC, Which Takes Action on Crypto, Beryl Investigation

Continued from page 17

Antonio could be overloaded and possibly lead to cascading outages.

ERCOT's solicitation for must-run alternatives to Braunig's retirement units resulted in one response. A 200-MW multi-hour energy storage resource responded within minutes of an Oct. 7 deadline, proposing to start in the summer of 2026 and end March 1, 2027.

The RMR contract would be ERCOT's first since 2016. The grid operator entered into an agreement with NRG Texas Power over a previously mothballed gas unit near Houston. It ended in 2017, thanks partly to transmission facilities that increased imports into the region.

New Rules for Crypto Miners

The PUC approved a *new rule* requiring virtual currency mining facilities in ERCOT to annually provide information related to their electricity demand, location and ownership, giving the grid operator more transparency into the market (*56962*).

Under the rule, cryptocurrency miners with a total load above 75 MW will have to register with the PUC as a large flexible load, capable of adjusting their power consumption in response to prices. The facilities must file a five-year projection of expected peak load for each year, including the percentage of load that meets the definition as interruptible. The rolling five-year projection will be repeated each year.

"I think it's really important that, as we're looking at [Texas'] load growth, that this help us give ERCOT and the market an understanding of what those actual projections are from the cryptocurrencies' standpoint," Commissioner Jimmy Glotfelty said. "Having them look five years out every year is a really important component of this for reliability."

The rule was mandated by *state law* as demand associated with virtual currency mining operations *has grown rapidly* in recent years, according to the U.S. Energy Information Administration.

PUC Completes Beryl Investigation

The commission approved several reports, including its *investigation* into two major weather events that hit the Houston area: a derecho in May and Hurricane Beryl in July.

At Gov. Greg Abbott's directive, the PUC assessed local utilities' emergency preparedness and their response to the two events (*56822*).

The PUC team made a number of recommendations to reduce the length and effect of power outages, including annual hurricane and storm drills between utilities, new performance standards and heavier fines, and a legal right to restoration timelines.

The investigation's summary will be added as an addendum to the broader report that all state agencies are required to file ahead of Texas' biennial legislative sessions. The 2025 session begins Jan. 14.

The PUC also approved:

- ERCOT's biennial report on the *operating reserve demand curve*, which will eventually be replaced by individual ancillary service demand curves under real-time co-optimization (*55999*); and
- an order finding ERCOT's proposed *ancillary service methodology* for 2025 is appropriate and necessary for the market's proper functioning (*54445*). ■

ERCOT News

Texas Now Wants to be No. 1 in Nuclear Power

Report to State Legislature Outlines Recommendations for Growth

By Tom Kleckner

AUSTIN, Texas — Not content with having the world's eighth-largest economy — bigger than Russia's — along with being a global leader in crude oil production and home to more wind and solar energy than any other state, Texas has set its sights on dominating nuclear energy production as well.

Texas officials released a report Nov. 18, titled "*Deploying a World-Renowned Advanced Nuclear Industry in Texas*," that lays out a path for the state to become a "global nuclear energy hub."

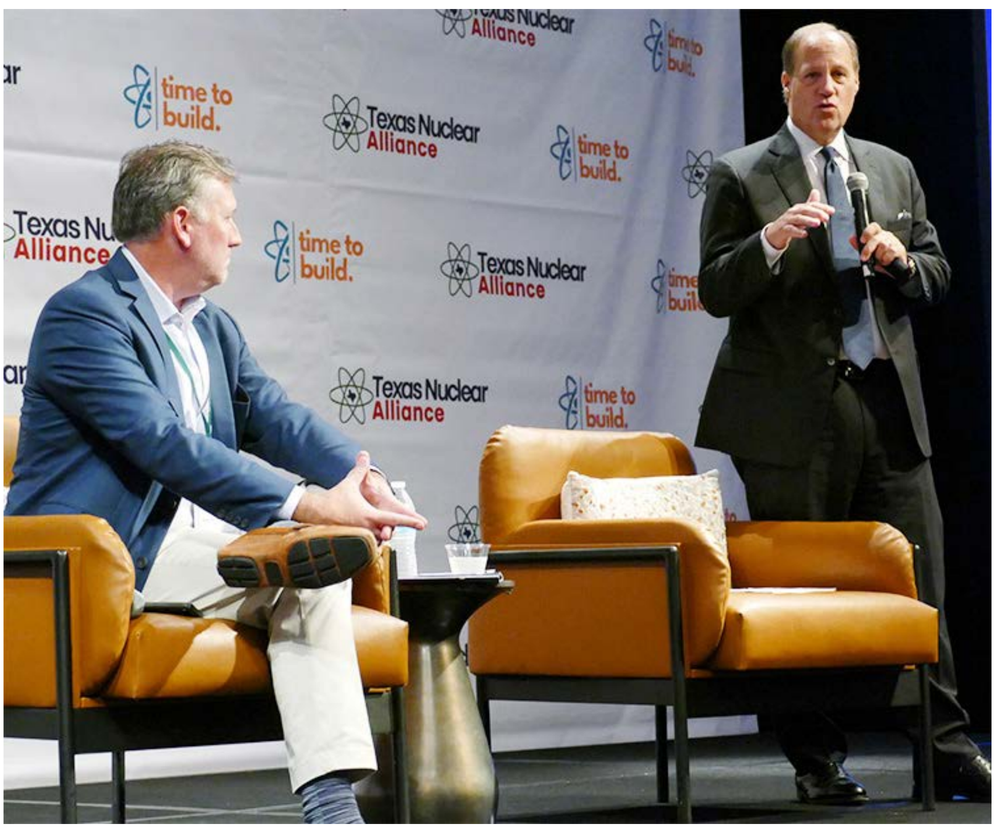
"Texas is the energy capital of the world, and we are ready to be No. 1 in advanced nuclear power," Texas Gov. Greg Abbott said in a *statement*. "By utilizing advanced nuclear energy, Texas will enhance the reliability of the state grid and provide affordable, dispatchable power to Texans across the state."

The report was shepherded by Jimmy Glotfelty, a Public Utility Commission of Texas member and chair of the working group tasked with studying and planning for the use of advanced nuclear reactors (ANRs) in Texas. The report became public just before Glotfelty sat down for a fireside chat at the Nov. 18 Texas Nuclear Summit.

"The governor wants us to be No. 1. We're No. 1 in wind, we're No. 1 in solar, we're No. 1 in oil production and gas production," Glotfelty told his audience. "What's next? Nuclear. That's our challenge. That's our challenge for the industrial sector. That's our challenge for the power sector. That's our challenge for the manufacturing sector, to be a part of this industry going forward.

"We hope this is a springboard to greater, bigger, better things in the nuclear space in Texas, and this is just the beginning," Glotfelty said. "This is the end of the beginning, and we've got a lot more work to do in the future."

Texas Nuclear Alliance President Reed Clay, the summit's host, said the state's leadership has laid the groundwork for "immense, unmatched nuclear potential to chart a bold path forward."



PUC Commissioner Jimmy Glotfelty (right), with Texas Nuclear Alliance President Reed Clay, details the report's recommendations during the Texas Nuclear Summit. | *© RTO Insider LLC*

Why This Matters

Already a global leader in energy, Texas now wants a starring role in the nuclear energy industry as well. The report lays out a number of critical issues for the industry in the state, most of which will require legislative solutions.

"The importance of nuclear energy to the state's future energy needs and for the continuation of the Texas miracle cannot be overstated," Clay said.

Texas has only four reactors at two sites, Comanche Peak near Fort Worth and the South Texas Project south of Houston, which provide over 5 GW of energy between them. However, both plants each have room for two more reactors.

But the interest in nuclear power is there, given the projections of 8% load growth. Texas A&M University has *asked* the Nuclear Regulatory Commission for an early site permit that would allow up to five 10- to 200-MW reactors to be built on its campus, making it the country's first higher education institution with a commercial nuclear reactor site license.

The NRC in September gave Abilene Christian University approval to *build and test* a 1-MW ANR that will be cooled by molten salt. Along the Gulf Coast, Dow Chemical and X-energy *plan to develop* four gas-cooled ANRs at a large chemical plant; it has already been selected for up to $50 million in federal funding but does not yet have regulatory approval.

'Not Chernobyl'

In a message to Abbott included in the report, Glotfelty said economics and federal licensing time frames — "neither of which the state can directly change" — are the "fundamental challenges" to achieving the state's objectives. However, he said the working group made seven recommendations to "prove up the state's role as a regulatory and economic leader in this new innovative technology."

The recommendations target critical industry issues in Texas, and most will require legislative solutions:

- Advanced nuclear authority.
- Nuclear permitting officer.
- Workforce development program.
- Advanced manufacturing institute.
- Nuclear public outreach program.
- Nuclear energy and supply chain fund.
- Nuclear energy fund.

The group foresees the advanced nuclear authority as a state agency to be the "tip of the spear" in providing a voice for the nuclear industry. The nuclear permitting officer would guide interested companies through the permitting process while workforce programs would train the next generation of nuclear employees, from the engineer down to the "most important welder," Glotfelty said.

"Our state has the ability to do it," he said. "We do it for other types of projects, and we will do it for the nuclear space as well."

The team also proposed a nuclear energy fund that would offer low-interest loans to developers, similar to the $10 billion Texas Energy Fund. Glotfelty said while he wishes the government didn't have to help fund the industry, state money will be involved "because we're competing with 50 other states." He said the state's $20 billion surplus, fueled by its oil and gas industry, provides an opportunity.

"We're helping reduce the front-end cost by putting state dollars at work," Glotfelty said.

The Texas Legislature's biennial session runs from Jan. 14 to June 2.

Then comes the hard part, Glotfelty said. While public opinion has softened on nuclear power since the 1980s, it hasn't reached the acceptance that wind and solar energy have.

"We've got to have coordinated effort to help people understand that Texas is not Chernobyl, that nuclear is not Three Mile Island and Fukushima," Glotfelty said.

"This end of the beginning is the report. Writing is done. Now it's the communicating," he added. "It's communicating with everybody at the local level. It's communicating with everybody in the legislature. It's communicating with your supply chain. It's communicating the fact that we want to build things here in Texas." ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

Members Endorse 2 Changes to Transmission Planning

ERCOT stakeholders approved a pair of protocol changes related to transmission planning as the Texas grid operator continues to grapple with connecting incoming load to its system.

During the Technical Advisory Committee's Nov. 20 meeting, members approved *NPRR1247*, which uses a consumer energy cost reduction test to measure congestion cost savings when evaluating economic transmission projects. They also approved *NPRR1180* and a related change to the Planning Guide (*PGRR107*) that incorporates a 2022 state law requiring any ERCOT reliability transmission project review to include the historical load, forecasted load growth and additional load seeking interconnection.

Several generators and retailers opposed the first protocol change, noting that congestion costs can be hedged but transmission costs can't.

"We think basing decisions on that is probably discounting a significant value that accrues to loads," Luminant's Ned Bonskowski said.

The NPRR was brought forward by ERCOT staff after collaborating with the Public Utility Commission. The ISO retained Energy and Environmental Economics (E3) to identify a set of viable options and provide recommendations for the most suitable congestion cost savings test. E3 presented its work in a March 2024 *white paper*, recommending a system-wide energy cost reduction test as the most suitable for ERCOT.

The ERCOT Technical Advisory Committee's November meeting | *ERCOT*

While staff approved E3's recommendations, Luminant said the proposed congestion cost savings test could increase costs for ratepayers when competitive market solutions could serve load less expensively. The generator suggested applying a .25 multiplier factor to the calculated system-wide consumer energy cost reduction before using it to determine a project's economic benefits.

"We think this may be a good compromise," Bonskowski said. "If there's a need to move forward on something today, we certainly would also support tabling and giving stakeholders just a little more time to work through this and make sure that we get this right before sending it up to the board."

However, the vote to table NPRR1247 fell short, 11-17, with one abstention.

Mark Bruce, speaking for Pattern Energy, said his client is still concerned about an overall lack of transparency and the need for further vetting. He said Luminant lacked backing data in its comments and urged stakeholders to revisit the matter with a change to the Planning Guide to further prevent the process's downstream effects.

"I know there's been some pressure from above to deliver something to the board on this at their next meeting," Bruce said. "My client's been engaged from the get-go, from its first showing as a draft before it was even filed. We've been trying to understand and perfect this very important revision request."

TAC eventually approved the measure 25-3, with one abstention. Luminant, Calpine and Shell North America all opposed the motion.

The committee approved *NPRR1180* 25-0, with four abstentions, two from consumer interests.

The Office of Public Utility Counsel's Nabaraj Pokharel said he supported the rule's legislative intent but stressed the importance of "ensuring that the load projection used for planning are as accurate as possible."

"There is a risk of unintended consequences, particularly if load studies are not thorough or accurate," he said. "While building transmission to meet actual load is necessary, [it] could result in unnecessary cost that would ultimately be borne by residential consumers."

To remedy that concern, Mark Dreyfus, speaking for a coalition of cities, suggested approving the protocol change and filing a follow-up revision request that drills down into the load-projection's validation process.

"There's a lot of projects waiting to have this process in place and we need to get moving on those projects," he said.

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Texas Competitive Power Advocates Executive Director Michele Richmond said several meetings with Oncor and other wires companies have resulted in a strawman proposal for another NPRR that would address the process' transparency and standardization.

"I think we are very comfortable with moving this forward, given that commitment and the really good discussions that we have been having," Richmond said.

Large Loads Need a Segment Home

TAC discussed with staff potential changes to the committee's segment makeup, driven by the growing influence of data centers and cryptocurrency miners that don't fit neatly into either the industrial consumer or large commercial segments.

ERCOT membership has risen from 257 members in 2021 to 356 this year, mostly because of large flexible loads. Staff has asked entities with large loads to register in the industrial segment when making their membership applications for 2025.

The grid operator's seven segments are used to fill out the 30-person TAC. Any changes to the representation would require an amendment to the bylaws and PUC approval.

"Things have changed a lot," Engie's Bob Helton said, alluding to a TAC segmentation that has been static since 2014. "Every time we talk about this, we have to be careful of balance. Anything we do is going to be a long, drawn-out deal to make sure that that balance remains in place and that no segment or group has a heavier weight than any other one in trying to approve things."

Staff said ERCOT now has just over 62 GW of large loads in its interconnection queue. It has added another gig of new standalone and co-located projects since October.

West Texas Project Endorsed

TAC members endorsed ERCOT's recommended $202.2 million Oncor project that addresses reliability issues in West Texas, placing it on the combination ballot.

The project stems from the 2019 *Delaware Basin Load Integration Study*. The region has significant oil and natural gas load and ERCOT's highest peak demand growth rate percentage in recent years.

The Regional Planning Group approved Oncor plans to upgrade an existing capacitor station, build 22 miles of double-circuit 345-kV lines, convert 41 miles of 138-kV lines to 345-kV, build 41 miles of new 138-kV lines, and install six 5000-A, 345-kV circuit breakers. The project is expected to be completed in 2027.

Because the project cost more than $100 million, making it a Tier 1 project, it must be approved by ERCOT's Board of Directors.

Co-chair Martin to Step Away

The meeting was the last as TAC's co-chair for Collin Martin, Oncor vice president of grid operations. Martin told his fellow members he is stepping away "partially" to focus on potential transmission projects in the Permian Basin.

"I appreciate everybody's confidence in being able to be seated to this on the table," he said. "It's been a great year. I learned a lot"

"I learned a lot from Collin," said TAC Chair Caitlin Smith, with Jupiter Power. "He brought a wide range of knowledge to TAC leadership, and not just the engineering side. He knows a lot about the market side and the systems and everything. I think having him here to add his perspective has been very valuable."

Fellow Oncor employee Martha Henson has been proposed as Martin's replacement. Smith will continue as chair.

HDL Override Change Tabled

TAC again tabled a protocol change (*NPRR1190*) that would recover demonstrable financial loss arising from a manual high dispatch limit (HDL) override to reduce real power output, should the output be used to meet qualified scheduling entity load obligations. Members directed their *Wholesale Market Subcommittee* to provide remarks on the change back to the *Protocol Revision Subcommittee* before they take it up again in January.

The change was approved by TAC in June. However, the board remanded it back to TAC in October over the consumer segment's concerns that the NPRR would reward over-scheduling of power that cannot be delivered. Members of that segment say that will force consumers to subsidize insufficient hedging by other market participants in the face of changing grid conditions. (See "2025 AS Methodology OK'd," *ERCOT Board of Directors Briefs: Oct. 9-10, 2024*.)

Reliant Energy Retail Services' Bill Barnes said he has discussed this with Eric Goff, who represents residential consumers but was unable to attend the meeting, and floated a concept from their conversation. He said it acknowledges consumer concerns about a situation where HDL overrides become a "dominant component" of the market.

"We would be more dependent on these out-of-market payments. That's not the goal of 1190. That's not the goal for any of us," he said.

Barnes said an annual settlement trigger, should ERCOT find itself in a situation where it hits a threshold amount of HDL payments, would lead to a review of protocol's the language. That would tighten the contracts eligible for some participants, he said.

Members unanimously endorsed a combo ballot that included four NPRRs and related changes to the Planning Guide (PGRR) and Nodal Operating Guide (NOGRR) and an Other Binding Document request that will do the following if approved by ERCOT's board:

- *NPRR1239*, *NOGRR266*: move reports that don't contain ERCOT critical energy infrastructure information (ECEII) from the market information system secure area to the public ERCOT website.
- *NPRR1240*, *NOGRR267*, *PGRR116*: move reports that don't contain ERCOT ECEII information from the market information system secure area to the public ERCOT website. The change also conforms rules with current posting practices, including those for maintaining ECEII lists of equipment in the outage scheduler; for making the annual planning model data submittal schedule available in the model-on-demand (MOD) application; and for posting weekly demand forecasts, demand analyses for 36 months and beyond, metrics of forecast error, and assessments of chronic congestion on the website.
- *NPRR1246*, *NOGRR268*, *OBDRR052*, *PGRR118*: insert terminology associated with energy storage resources (ESRs) into the protocols, aligning the ESRs' provisions and requirements with those for generation resources and controllable load resources. The change applies to ESRs in the future single-model era and should be implemented simultaneously with *NPRR1014* (BESTF-4 Energy Storage Resource Single Model).
- *NPRR1254*: require resource entities to submit the initial resource registration data for a generator interconnection or modification (GIM) project four months prior to target inclusion in the ERCOT network operations model. This gives ERCOT and the entities one month to address errors or deficiencies. ■

— Tom Kleckner

ISO-NE Details Regional Energy Shortfall Threshold Metrics

NEPOOL Reliability Committee Reviews NECEC Agreements, New Planning Procedure

By Jon Lamson

ISO-NE's Regional Energy Shortfall Threshold (REST) will rely on a pair of metrics intended to capture the intensity and duration of energy shortfall risks in extreme weather scenarios, the RTO *told the NEPOOL Reliability Committee* on Nov. 19.

The REST project is an effort to define an acceptable threshold for ISO-NE's seasonal risk modeling, which will use the RTO's newly developed probabilistic energy adequacy tool (PEAT). ISO-NE is planning to use the REST to evaluate whether additional actions will be needed to support system reliability ahead of winter and summer seasons.

The modeling features a "multiday rolling-horizon economic dispatch," which includes both preventive and corrective measures from the RTO and incorporates generator opportunity costs. (See *ISO-NE Boosts Energy Adequacy Modeling Capabilities*.)

In the seasonal outlook for the upcoming winter — which marks ISO-NE's first time using the PEAT in a seasonal analysis — the RTO's modeling found manageable shortfall risks. (See *ISO-NE Sees Manageable Shortfall Risk for Upcoming Winter*.) In the future, the REST and its associated metrics are intended to help standardize this evaluation.

To assess the magnitude of shortfall risks, ISO-NE is planning to calculate the normalized unserved energy (NUE), defined as total shortfall relative to demand, over the most extreme 72-hour cases identified by the model. This will indicate what percentage of load would experience shortfall in the low-probability events identified.

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

To evaluate shortfall duration, the RTO will calculate the length of the most extreme scenarios, looking beyond the 72-hour window used to calculate intensity.

Mike Knowland, manager of operations forecast and scheduling for ISO-NE, said the duration and magnitude metrics will complement each other and are both "critical metrics for assessing energy adequacy risk under extreme conditions." He added that ISO-NE "is still evaluating how best to incorporate these two metrics into its REST proposal."

ISO-NE is still taking feedback on the proposed metrics, and it plans to continue stakeholder discussions on the proposal through January or February of 2025. Once the metrics are established, the RTO is planning to present an initial proposal on risk thresholds in March or April.

The establishment of the REST directly relates to how much the region is willing to spend to limit the potential reliability effects of low-probability weather events, and it could raise tough questions about the tradeoffs between reliability, affordability and decarbonization. ISO-NE has indicated that it expects the states to play a major role in establishing this threshold.

NECEC Agreements

Also at the RC, *ISO-NE reviewed* the Transmission Operating Agreement and Interconnection Operators Agreement for the New England Clean Energy Connect (NECEC) transmission line.

The 1,200-MW line was solicited by Massachusetts and would facilitate additional imports from Hydro-Québec. Avangrid, the project developer, recently indicated the line has a best-case in-service date of January 2026. (See *Avangrid Sues NextEra over 'Scorched-earth Scheme' to Stop NECEC*.)

ISO-NE is planning to file the agreements with FERC in the first half of 2025 and is seeking an advisory vote from the RC on the interconnection agreement, as well as a vote from the NEPOOL Transmission Committee on the transmission agreement.

The TOA between ISO-NE and NECEC would give the RTO operating authority over the line, which includes responsibility for generation dispatch, real-time balancing, establishing operating limits and exchanging transmission security information to the relevant parties.

> **What's Next**
>
> The RTO will continue working with stakeholders in the coming months to refine the metrics before proposing a shortfall threshold in the spring.

The agreement also includes "a standard 'grandfathered agreements' provision," which includes rights of Massachusetts' electric distribution companies to receive power from the line, ISO-NE said. These rights can be overridden by "short-term reliability actions."

The interconnection agreement between Hydro-Québec and ISO-NE governs the "coordinated operation and scheduling of energy and ancillary services," emergency energy exchanges, outage scheduling and the "treatment of inadvertent interchange."

While the NECEC contracts between Massachusetts' EDCs and Hydro-Québec are intended to facilitate the one-way flow of power from Canada to the U.S., the line will be capable of sending power in both directions, ISO-NE said. This will allow for emergency south-to-north transmission, although the system impact of these flows still needs to be studied, the RTO added.

The RC is scheduled to vote on the interconnection agreement in January.

Planning Procedure for Data Collection

Steven Judd, ISO-NE manager of resource adequacy and accreditation, *outlined* the RTO's proposal for a new planning procedure (PP-14) focused on generator data reporting requirements, which is intended "to provide structure and guidance for lead market participants responsible for reporting monthly data."

"This procedure will describe the data submission timelines, reporting requirements and validation processes for the required data," Judd said. He added that standardizing the reporting requirements and guidelines will help ensure system reliability.

The RC will also vote on the proposal in January. ■

ISO-NE News

US, Canadian Leaders Discuss Affordability of Energy Transition

By Jon Lamson

NERC CEO Jim Robb addresses the conference. | *© RTO Insider LLC*

BOSTON — Energy leaders from the U.S. and Canada grappled with the challenges of balancing decarbonization and affordability at the New England-Canada Business Council's (NECBC's) Executive Energy Conference on Nov. 20-21, discussing how collaboration could lower the cost of the clean energy transition on both sides of the border.

Retail electricity rates in New England are *rising faster* than nearly all other regions in the U.S., while Hydro-Québec is *planning* to spend billions to meet demand growth, which it expects to put "upward pressure on electricity rates."

To juggle major investments preparing for load growth, upgrading aging infrastructure, and incorporating and balancing intermittent renewables, "there needs to be a different way to look at how the investment is funded," said Nicola Medalova, COO of National Grid's New England electric business.

Central Maine Power CEO Joseph Purington echoed Medalova's concerns, saying the increase of public policy costs in electric rates is "not sustainable."

"We have to start thinking about public policies and the public policy component of the bill," Purington said. He wondered if some of those costs should be "spread across as a tax instead of as a part of your electric bill."

The potential loss of federal clean energy funding with the incoming Trump administration will likely add a layer of difficulty for states looking to meet their climate goals without overburdening ratepayers.

Electricity bills can be a regressive funding mechanism to support public policy initiatives: Rising energy costs *disproportionately affect* low-income individuals, who are often forced to choose between paying energy bills and covering other essential needs like food and health care.

Why This Matters

Affordability challenges could threaten to derail the clean energy transition on both sides of the border, with states and provinces grappling with a confluence of global economic pressures and political uncertainty.

Discount rates can only do so much to mitigate the issue, Medalova said, adding that rate pressures can drive up economy-wide living costs. "Whenever you give a discount, somebody else is picking up the weight of that bill."

North of the border, political uncertainty in Canada similarly threatens the availability of federal funding, said Monica Gattinger, a political studies professor at the University of Ottawa. Gattinger said public opinion shows climate change has been "dropping like a stone" in the public's list of priorities, adding that a conservative government "would likely reverse many, if not all, of these policies."

Competing Priorities

Speakers at the conference discussed a wide range of solutions to help balance the often competing priorities of affordability, reliability and decarbonization.

Medalova and Purington both emphasized the need to unlock retail demand flexibility, a sentiment that was echoed by several other speakers throughout the conference.

ISO-NE CEO Gordon van Welie highlighted the RTO's finding from its *2050 Transmission Study* that a 10% reduction in the 2050 peak load could reduce the required transmission buildout by about a third.

The RTO projects the region's peak demand to more than double by 2050 and estimates the transmission buildout could cost up to $26 billion. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B* and *ISO-NE Analysis Shows Benefits of Shifting OSW Interconnection Points*.)

Winston Morton, CEO of *Climative*, said there is a large amount of remaining potential in energy-efficiency upgrades. He added that these gains have been constrained by the limited scale of state energy-efficiency programs and the gap in capital needed to finance building retrofits.

"We've got to attract private capital into the

ISO-NE News

market as quickly as we can," Morton said, noting that he sees "a positive return on investment for every retrofit."

Along with transmission needs, load growth will also pose significant resource adequacy challenges for the Northeast.

"We've got to figure out how to balance load growth and electrification efforts with reliability," said NERC CEO Jim Robb, adding that he is "a big advocate of natural gas generation, because it's so flexible and it can help meet the afternoon ramp."

Natural gas is the dominant source of electricity generation in New England, and gas-fired generation has been steadily increasing in recent years.

"There is a critical need for gas throughout the year," said Richard Levitan, president of energy management consultancy Levitan & Associates.

Toby Rice, CEO of EQT, one of the U.S.' largest gas producers, pitched attendees on the need to increase natural gas pipeline capacity into the region.

"We've hit a wall," Rice said. "We just need more infrastructure to connect markets."

Rice chided environmentalists for opposing pipeline projects and argued that additional gas infrastructure would help reduce emissions by displacing coal or oil.

"They should be supporting pipelines because of their concern for climate," he said.

While replacing coal or oil with natural gas can bring some emissions reductions depending on how much methane is leaked from the system, coal and oil only make up a small fraction of the generation mix in New England, Québec and the Maritime provinces, apart from Nova Scotia.

Increased gas generation has caused greater power system emissions in New England *in the past year*, and a long-term rise in gas consumption would likely undermine the climate goals set by New England states. Massachusetts state law includes *sector-specific emissions limits* with increasingly stringent decarbonization targets through 2050.

Rice also argued that increasing LNG export capacity would drive down global emissions, although the climate case for exported LNG is murky. One *peer-reviewed study* published in October found exported LNG to have a 33% larger carbon footprint than coal over a 20-year period.

Van Welie expressed skepticism that New England would see new pipelines, citing a lack of customers. However, he stressed that existing resources must not be retired faster than new renewables are deployed, especially with anticipated load growth. An ISO-NE study on deep decarbonization published in October found a significant need for clean dispatchable resources to balance renewables. (See *ISO-NE Study Lays Out Challenges of Deep Decarbonization*.) The study singled out small modular nuclear reactors (SMRs), synthetic natural gas and multiday energy storage as potential solutions to help meet these needs.

Rudy Cuzzetto, a member of the Legislative Assembly of Ontario, discussed the province's work to help commercialize SMRs. Ontario will likely have the world's first full-scale SMR — with a capacity of 300 MW — in operation by 2029, he said.

"The world is looking at Ontario right now," Cuzzetto said. "We are going to be a powerhouse in Ontario [and] be able to export electricity across the world."

Québec's vast hydropower resources could also help to fill the need for dispatchable power, said Serge Abergel, COO for Hydro-Québec Energy Services.

Despite a drop in exports in 2023 from low reservoir levels, Hydro-Québec has indicated that long-term changes to the role that its hydroelectric resources play on the grid could bring savings across the Northeast. (See *Québec, New England See Shifting Role for Canadian Hydropower*.)

"We are interested in optimizing our grid for our neighbors," Abergel said. "Let's have a conversation on regional planning for the long term. Maybe we can save some ratepayer money."

In theory, increased bilateral transmission capacity between the two countries could provide significant benefits when paired with a surplus of renewables on the New England grid. This would allow New England to export cheap power during periods of excess renewable generation, while enabling Québec to conserve hydropower and send power back to the U.S. during renewable lulls.

Abergel said the company sees "significant savings, especially when you start looking at 2040 and onwards."

Responding to Abergel's pitch, van Welie said this dynamic would require agreements to provide "a reciprocal benefit" between regions and to ensure Hydro-Québec sells the power back to New England at a reasonable price during periods of low renewable generation. ■

From left: Robin Main, Hinckley Allen; Serge Abergel, Hydro-Québec Energy Services; Nicola Medalova, National Grid; and Central Maine Power CEO Joseph Purington | *© RTO Insider LLC*

MISO News

MISO Outlines Plan on Fast-track Queue for Resource Adequacy

By Amanda Durish Cook

MISO hopes to file a proposal in February to create an exclusive, faster route through its interconnection queue for generation projects that are key to maintaining resource adequacy.

At a special Nov. 18 workshop, Director of Resource Utilization Andy Witmeier said MISO hopes to have the fast-track process in place by June for generation projects that are key to sustaining resource adequacy over a five-year horizon. (See *MISO to Devise Express Lane in Queue for Generation Projects that Keep Lights On*.)

Witmeier emphasized that MISO sees the fast pass as a short-term fix, with a sunset date included in the proposal. That date would be based on the RTO's best estimate for when it might have its interconnection process streamlined enough to achieve a one-year queue wait time for generation projects.

"It will take us time to get a one-year queue process," Witmeier warned.

Some stakeholders said dividing the queue into two parallel processes with one given priority might result in two clogged queues, making MISO's ultimate goal of a single, yearlong process even more unattainable.

Witmeier said MISO's automatic withdrawal penalties currently in place for the traditional queue will likely curb the late-stage withdrawals that set restudies in motion and make processing sluggish.

"The restudies on the older cycles is preventing us from finalizing the newer cycles. … We're plagued with restudies. And we can't wait for that any longer," Witmeier said.

"What I can tell you is, if I'm not down to a one-year queue cycle by 2028, I'm paying penalties," he added, invoking FERC's Order 2023.

Why This Matters

By summer, MISO hopes it can usher generation proposals critical to resource adequacy through a special, temporary express lane in its interconnection queue. The RTO is counting on states and LSEs to prove which projects deserve the expedited treatment.

Entergy's New Orleans Power Station under construction around 2020 | *Entergy*

Witmeier said that to enter the expedited process, generators must be part of a plan from a load-serving entity, be able to come online within three to five years for a known RA need, have network service to be deliverable and have endorsement by their state as a necessary project. MISO would not discriminate based on fuel type as long as a project is deemed essential.

The RTO is working with the Organization of MISO States on what documentation that states and authorities might use to demonstrate that a project is necessary, and how that documentation might differ for projects located in MISO's deregulated areas.

Witmeier also said MISO will need to establish a cost allocation method for the projects. The RTO would probably charge a higher, nonrefundable application fee to cover staff hours for the studies, which will be conducted serial-style instead of in batches.

Clean Grid Alliance's Beth Soholt asked what would happen if a project enters the expedited queue only to not ultimately receive a certificate of public convenience and necessity.

"Ultimately, whether or not to recognize that project is necessary as a resource adequacy project is up to that jurisdiction," MISO Deputy General Counsel Kristina Tridico said.

"We think the likelihood of projects going into [the expedited queue] and dropping out is very low," Witmeier added. Projects that have state backing are already usually considered foregone conclusions, he said.

Travis Stewart, representing the Coalition of Midwest Power Producers, said that even an express lane will not make RA projects "immune" from the exorbitant network upgrade costs often found in MISO interconnection studies.

But Witmeier said that under the expedited processing, developers should get a clearer idea sooner of network upgrade costs.

"We expect a lot of these LSEs will have done their due diligence and done their own studies on expected network upgrades," he added.

So far, MISO is not proposing a withdrawal penalty for the expedited class of projects. Stakeholders asked it to reconsider that stance, arguing that even those projects could be canceled.

Sustainable FERC Project's Natalie McIntire said existing projects in the regular queue might be harmed financially through expedited projects snapping up available transmission capacity first. She asked how MISO would make sure that the regular queue is still viable.

Witmeier said MISO will draw on the same system modeling for the regular and accelerated processes. He said projects in both queues would have a chance to claim transmission capacity on the system. After that, MISO would consider it unavailable.

McIntire said she did not see how, somewhere along the line, the parallel processes would not assign the same transmission spot to two projects.

"It seems to me we have a math problem," McIntire said.

"It seems like an age-old problem that we've had, and we're compounding it," WEC Energy Group's Chris Plante agreed.

MISO will hold another workshop to hammer out details on its expedited resource adequacy queue studies Dec. 6. ■

MISO News

MISO Draws in Experts for Probabilistic Planning Symposium

By Amanda Durish Cook

Why This Matters

Factors such as climate change and load growth mean that existing transmission planning methods used by grid planners are insufficient, necessitating the development of new, probabilistic approaches.

CARMEL, Ind. — MISO further embraced the industry's move to chance-based transmission planning by hosting a Probabilistic Planning Symposium at its headquarters.

The grid operator and consulting firm Energy and Environmental Economics pulled together stakeholders, other RTO planners, researchers and tech representatives to probe prospective planning methods and fret over the shortcomings of current practices Nov. 19-20.

Director of Economic and Policy Planning Christina Drake said when she joined MISO, planning was carried out on a relatively gradual timeline compared to the urgency today.

"We're seeing these loads come on quicker than we can keep up," she told attendees.

Drake said of late, MISO is having "friendly but frank" conversations with companies whose building goals are stymied by the limits of today's transmission capacity.

She said just a few years ago, MISO was met with skepticism that its third, most aggressive planning scenario — which predicted electrification stimulating significant demand — would ever come to pass.

MISO announced earlier in November that it will revise its three, 20-year transmission planning futures — which envision the clean energy transition at a walk, a jog and a run — to be more in touch with recent realities of surprising load growth and accelerated clean energy goals. (See *MISO Pauses Long-range Tx Planning in 2025 to go Back to the Futures*.)

"And now we're getting feedback that we think you're near your top end on your load [predictions]," Drake said. "The drivers are changing. It's no longer electrification; it's things with hydrogen and data centers. That's very different."

Drake said the pace of change is so dramatic that MISO's planning modeling is becoming unsolvable. "Our tools have never seen this. It's pushing our models to the brink," she said. "Now we're projecting things 10 years faster."

SPP Manager of Transmission Planning Kirk Hall seconded experiencing trouble trying to produce realistic models.

"We're having to constantly add fictitious equipment … just to get our reliability models to solve," he said.

"If you're asking if the probabilistic planning tools are sufficient? The answer is no," NYISO Director of System Planning Yachi Lin said.

Lin said New York's past 35 years contained little in the way of transmission planning. Recent years, on the other hand, have contained about $15 billion in transmission and distribution investment, she said, owing to the state's progressive climate goals.

Lin said New York City alone has an "acute" problem of having to retire several aging, combined cycle units, while new, zero-emission generation needs to occupy as little acreage as possible. She said advanced technology is years away, with a "big gap of getting there." Lin likened transmission planning around those unknowns to layering up slices of Swiss cheese.

"There are holes, we know. But hopefully, if you have enough slices, you can cover the gaps," she said.

Drake said building an economic model takes an amount of work that's often not appreciated. She said it's a level of challenge that's on par with delivering a baby.

"It took a solid nine months, and there was a lot of crying and pain in the middle," she joked of creating a successful model.

Drake added that just to get a model to solve today takes an "intense" effort. She said she felt like bringing planners a "Gatorade and a towel" after they're successful.

ERCOT Power Systems Engineer Eric Meier also said that there aren't any tools "off the shelf" today that can effectively evaluate probabilistic planning.

Drake said grid planners' challenges are compounded by trying to anticipate yearly bouts of increasingly extreme weather and generation outages.

"This is new territory for all the RTOs," she said.

Drake said extreme weather instances are driving an "insatiable" need to improve interregional transfer capability, evidenced by MISO's new interregional studies with SPP and PJM.

During the symposium, grid planners named other obstacles to identifying the most useful transmission projects decades in advance.

MISO Senior Manager of Policy and Regulatory Planning RaeLynn Asah said load growth is the greatest uncertainty for today's planning.

"It's astronomical — I don't know what word I want to use. It's so large, and it's so unknown," Asah said.

Asah also said too-slow regulatory processes and seized-up supply chains are sources of anxiety. "They are a big deal. They keep me up at night," she said.

However, Asah said there's reason for hope. She said MISO is building a new planning model designed to be more responsive so MISO more easily can incorporate stakeholder suggestions and influence the model.

"I want to end on hope instead of the things we can't do yet," she said.

Lin said retaining a planning staff is becoming more challenging with stiff competition between planning organizations. "It's a friendly competition among the ISOs/RTOs. And that's great, but we always want to make sure our people are taken care of," she said.

Climate Unknowns

MISO dedicated panels to climate change, a little-used phrase among the politically agnostic grid planner.

Argonne National Laboratory engineer Neal Mann said the lab's *projections* of future weather patterns across a range of scenarios through midcentury and end of century seek to predict the more frequent heating and cooling degree days in addition to risks like flooding.

Mann said planners might want to "use their neighbors like a battery" to tap into their supply when they fall short.

The Electric Power Research Institute's Parag Mitra said EPRI's Climate Resilience and Adaptation Initiative (READi) collaborative model helps planners make decisions that will make the system more durable against ever more dangerous weather. Mitra said planners need to have a good understanding of how weather can affect assets.

MISO News

Con Edison's William Gunther said his utility is analyzing future multiday wind lulls and high midday solar output that is squirreled away in storage for later use. He said a Con Edison climate vulnerability *study* delved into how high substations need to be positioned due to sea level rise as well as the potential for undergrounding lines when temperatures are too hot for transformers to be in the open air.

Mitra said while there is a need for scenario-based planning that draws on probabilities of extreme events, it's also valuable to analyze extreme events after the fact to pinpoint where conditions began a downward slide. He said demand response also can play a role in climate resilience.

But University of Michigan Professor Michael Craig said he discouraged planners from assigning climate disaster probabilities for planning purposes.

"When we think about climate change, I want to advise against using probabilities. Because we do not know … a meaningful probability of future climate scenarios," Craig said. "Climate change is not a problem for 30 years from now; it's increasing extremes today and tomorrow and the year after."

Instead, Craig advocated stress testing solutions in modeling against wide-ranging degrees of extreme heat, extreme storms and extreme drought.

"It's not like we hit 2050 and it turns over. Every year, those dice get loaded; every year you might have more extremes," he explained.

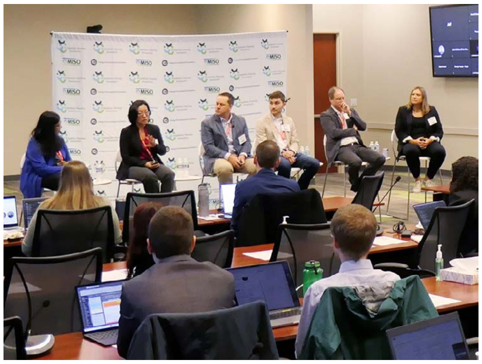
New Analytics

Johns Hopkins University professor Benjamin Hobbs advised grid planners to adopt stochastic programming, which mulls multiple scenarios simultaneously and uses decision trees to come up with the most beneficial investments. He said MISO comes close to stochastic planning with its futures-based planning.

"The grid that you're building needs to be nimble to be adaptive to economics, policy, climate," Hobbs said.

Hobbs said a stochastic approach is useful for MISO, which contains states with and without carbon limits and renewable portfolio standards.

He said MISO could plug in variables like technological advancements, load growth, fuel costs, capital costs and carbon costs and limit potential solutions by constraints like siting limitations, emissions reduction standards and Kirchoff's circuit laws.



A panel with NYISO's Yachi Lin (second from left), SPP's Kirk Hall, ERCOT's Eric Meier, PJM's Emmanuele Bobbio and MISO's Christina Drake | *© RTO Insider LLC*

Hobbs said he wasn't suggesting planners could "naively" load up variables and expect a model to pinpoint the best grid solution. "What you're getting from the model is suggestions," he said. "All forecasts are wrong, so it's important to consider a wide range of them."

Iowa State University professor James McCalley made a case for adaptive co-optimized expansion planning, which shows the costs of grid expansions based on a specific future build (or a core) and the costs of adaptations to the original plan that may be necessary.

McCalley said the adaptive approach is a "cousin" of stochastic planning but not the same because the method is designed to show costs through time.

"I would make the case that both of these methods are useful tools in a planner's toolbelt to understand the best way forward," he said.

McCalley said adaptive co-optimized planning shouldn't be a substitute for the PROMOD commitment and dispatch model, Siemens' PSS®E Power Simulator or EPRI's Electric Generation Expansion Analysis System. Rather, he said the method should be layered over them as an application to guide decisions.

McCalley said planners should continue to use their deterministic tools and introduce new, probabilistic analyses until they form a "single integrated method of doing the work."

McCalley said he knows firsthand from his experience as a PG&E planner in the late '80s that deterministic planning leaves much to be desired. He recalled being grilled over planning practices in front of the California Public Utilities Commission.

"Probabilistic planning isn't going to be a quantum leap for anyone. It's going to be a journey, and we need to start now," Mitra said.

AI Assistance

"Our grids are facing pressures like they've never faced before," Microsoft's Bilal Khursheed agreed, but offered AI as a means to lessen the tension.

Khursheed said the recent leaps in AI can better balance supply and demand in real time, improve resource utilization, assist in resource planning, better predict maintenance, provide the best insights to operators and speed the clean energy transition, among other things.

"These advancements aren't incremental. They're truly transformational in nature," he said.

Khursheed said grid planners should think of AI as "the brain of modern grid flexibility," the internet of things as "the eyes and ears of the grid" and the cloud as "the backbone of the ecosystem." He also said planners first must consider the "balancing act" of using the most they can from existing assets before deciding to physically expand the grid.

"It's not just about building more. It's about spending only when we absolutely have to," he said.

Khursheed said AI's sophistication can defer capacity investments by harnessing virtual power plants to provide flexible resource adequacy. He said Microsoft recently worked with a "large western European" transmission operator and found that it could cut "overcommitted fossil fuel resources" by 17 GW over the length of the pilot program through high-performance AI computing that helps operators make better use of cheaper, carbon-free resources.

The pilot saved the operator "millions of Euros," Khursheed said, and the topology optimizer is set to be rolled out on a large scale in the footprint.

Khursheed said transmission operators are shifting from being "reactive" when facing storms and temperature extremes and using generative AI to figure out earlier which assets are likely to take a hit and what transfer capability stands to be the most helpful.

However, Khursheed said Microsoft is risk-averse and thus far is making sure AI is providing more accurate data sooner to "drive levels of productivity we've not seen before" but not running the grid autonomously.

"There's still a human-in-the-loop component," he said. ■

OMS Survey: Another 1-GW Jump in DERs in MISO Footprint

By Amanda Durish Cook

By the Organization of MISO States' count, MISO is up to nearly 13.6 GW of distributed energy resources in the footprint.

Results from OMS's seventh annual DER *survey*, released Nov. 18, showed an approximate 1-GW growth from the total 12.5 GW of DERs OMS tallied in MISO in 2023. (See *Annual OMS DER Survey Records 1-GW Rise in MISO Residential Capacity*.) OMS has been recording 1-GW gains in MISO DERs since 2022. Unlike last year, virtually all the DER gains in 2024 came from non-residential sources.

Of the counted DERs, OMS said almost 3.1 GW comes from residential sources, representing a less pronounced, 140-MW climb year-over-year. OMS continues to find that solar and demand response are the most popular forms of DERs across all MISO planning resource zones, constituting 42 and 43% of survey totals, respectively. The organization said, once again, non-residential DERs that are registered with MISO account for the most capacity.

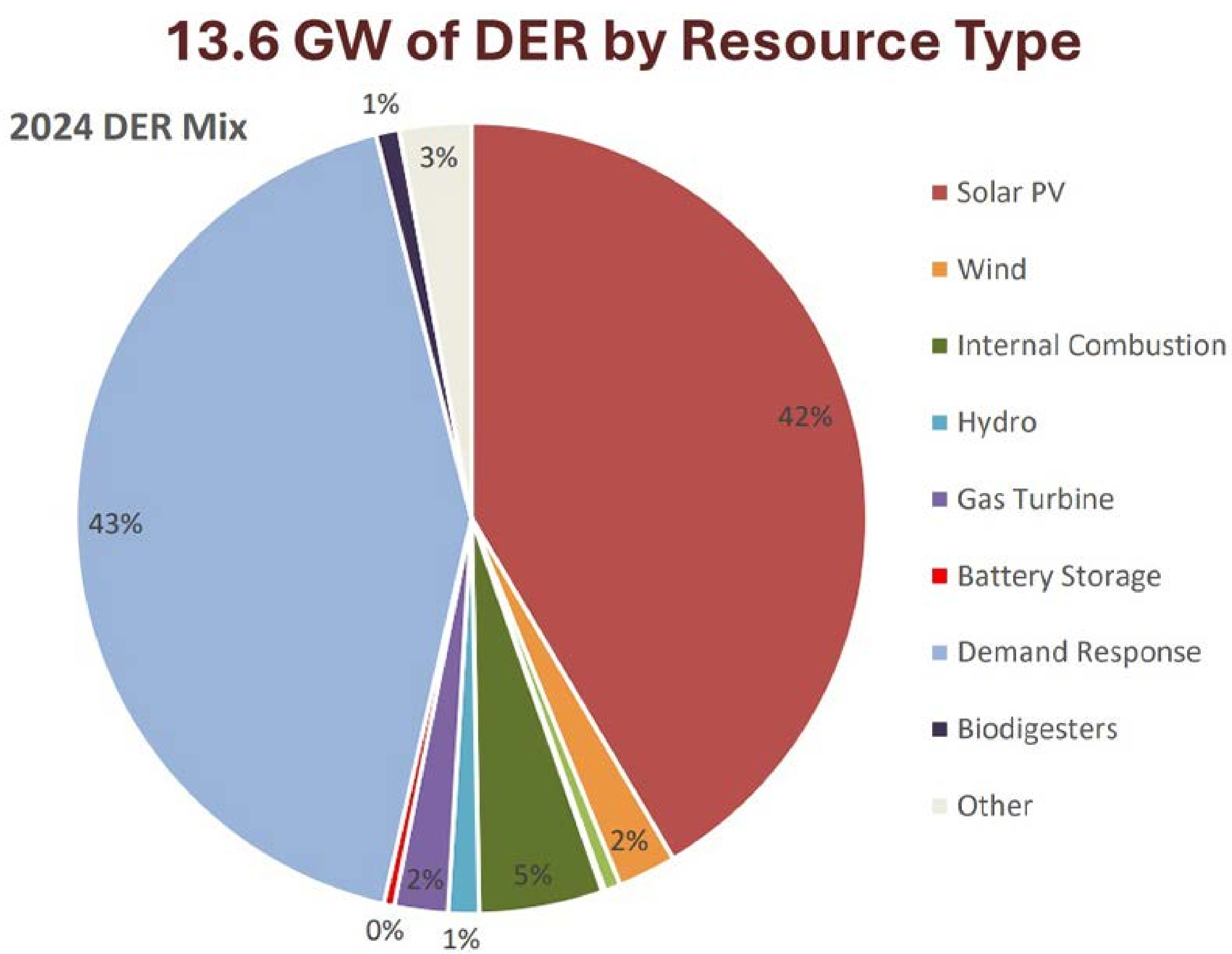
Similar to results from 2023, OMS found the bulk of DERs in Minnesota, Wisconsin, the Dakotas' Zone 1 and Michigan's Zone 7. Zone 1 contains about 3.45 GW, while Zone 7 plays host to about 2.75 GW. Those zones individually boast more DER capacity than OMS found systemwide in its first DER survey in 2018 at 2.58 GW.

Mississippi's Zone 10 once again has the least amount of DERs, OMS found, at just 67 MW.

OMS said several utilities responding to this year's survey "noted a need for state regulatory direction and the benefits of a common data-sharing platform" for DERs. OMS itself has stressed the need for MISO to take the lead on creating an information sharing platform for DERs as part of the RTO's compliance with Order 2222. During its board meetings, some OMS members have said MISO's lack of a standardized system for coordinated DER data sharing is a glaring omission as MISO prepares to accept DER aggregations into its markets.

OMS said most utility respondents reported they're either implementing or considering implementing advanced metering, demand-side management, a DER management system or another form of improved communication to better use DERs. Most also said their state's DER interconnection standards need to be updated. Still, the majority said they're not seeing transmission impacts because of DER growth.

At a Nov. 11 OMS board meeting, OMS Executive Director Tricia DeBleeckere said this year's DER survey probably showed more DERs because: more utilities responded to the survey; DERs have grown in number; and utilities likely have better tracking and awareness of the resources on their distribution systems. ■



A breakdown of the 2024 OMS DER Survey results | *OMS*

La. PSC Reviewing Entergy Request for $5B Data Center with Gas Gen

By Amanda Durish Cook

The Louisiana Public Service Commission has taken the first steps to consider Entergy's request to power a proposed $5 billion artificial intelligence data center in northern Louisiana with $3.2 billion in mostly natural gas generation.

Louisiana commissioners at their Nov. 20 *meeting* voted unanimously to hire familiar firms Stone Pigman and the Sisung Group's United Professionals Co. to review Entergy Louisiana's application (*U-37425*), which could spell a possible 25% increase in its generation, according to commissioners.

Though Entergy continues not to name the customer, multiple news outlets reported that Public Service Commissioner Foster Campbell confirmed outside of the meeting that Facebook parent Meta seeks to raise an AI data center in Richland Parish. Meta currently does not list a Louisiana-based data center among its *plans*.

According to its filing made earlier in November, Entergy plans to build three new combined cycle natural gas generators at a combined 2.26 GW, a new 500-kV transmission line and substation, and other upgrades to host the unnamed large customer. Entergy seeks cost recovery and rate-making treatment for the project, as well as a corporate sustainability rider, where the customer would commit to funding 1.5 GW of new solar or solar and storage hybrid generation. Entergy also requests an exemption from an RFP competitive solicitation process and a ruling from the commission by October 2025.

In a statement to *RTO Insider*, Entergy again declined to identify the customer, with spokesperson Neal Kirby saying the utility is "not able to identify the type or scope of the customer until the customer is ready to disclose their plans."

Entergy said in its filing that it expects the data center "has the potential to transform the economic landscape" of northern Louisiana and "employ directly 300 to 500 employees with an average salary of $82,000, in a region of the state that has long struggled with a lack of economic development and high levels of poverty."

Richland Parish's approximately 20,000 residents have an average $25,285 per capita income, *according* to the U.S. Census Bureau.

"This is the best news that we've had in north Louisiana in a long, long time. So, I'm for it 1,000%. We need it more than anybody. This data center would be a godsend for northeast Louisiana," Campbell said at the meeting, adding that the data center could represent an investment of anywhere from $5 billion to $10 billion.

Campbell said he thought the facility is all but a given and added that a lot of people "will have good-paying jobs."

The Louisiana PSC allowed consulting firm United Professionals a maximum of $675,000 and law firm Stone Pigman a maximum of $788,000 to evaluate Entergy's request.

"This is a very expansive docket that may require, depending on what happens with intervenors and whatnot, very extensive legal work and legal services. We're talking about the approval, certification of five different resources, including three generating resources, one high-voltage transmission line and upgrades of a transmission substation. So, it's all rolled into one proceeding that needs to be handled on an expedited basis. The customer here has expressed a need to get this done quickly, to get this data center to market very quickly," Stone Pigman attorney Dana Shelton explained to the commission. She added that she anticipated hearings in the docket.

Commissioner Davante Lewis said that while the commission is on "an [expedited] timeline," he urged the law firm to make sure "every intervenor is heard" and asked for a "thorough review."

"There are a lot of complicated issues that should be worked out that could be beneficial, especially when we're talking about the generation capacity, the water consumption," Lewis said. "These are long-term commitments; these are big projects."

Shelton said while she was "encouraged by the package Entergy has put on the table," her firm would make sure "unwarranted costs are not visited on our residential ratepayers."

Longtime PSC consultant Lane Sisung, of United Professionals, told commissioners his evaluation will be complex because it involves not one but three generators, associated transmission and "future rate mechanisms to allow a single customer access to renewable portfolios."

"It has many elements to it that aren't normally within a bid," Sisung said, adding that the consulting firm also would monitor Entergy's construction and conduct a prudence review.

Entergy did not respond to *RTO Insider*'s request for comment on how the three new gas plants could fit into Meta's zero-carbon target coming due within six years. Meta has a goal to reach net zero emissions across its "value chain," which extends beyond its data centers to its suppliers, sometime in 2030. Kirby said Entergy is committed to its own net zero by 2050 emissions *goal*, but did not address the 20-year mismatch between Entergy's and Meta's aims.

In its filing, Entergy said the unnamed customer has "robust sustainability goals." The utility added that it explored alternatives but didn't find any as strong a trio of new gas plants.

The Alliance for Affordable Energy, the Southern Renewable Energy Association (SREA) and the Union of Concerned Scientists already have petitioned to intervene in the case. SREA's filing indicates Entergy's requested exemption from a competitive solicitation for the generation would "unfairly limit competition."

During the utility's most recent earnings call, Entergy CEO Drew Marsh said the new industrial customer — presumably Meta — signed a 15-year electric service agreement with Entergy Louisiana. Marsh at the time also said Entergy was in "active discussions" about carbon capture solutions with customers, refraining from naming any.

Marsh also mentioned Entergy Louisiana's front-end engineering and design study to evaluate the technical and financial feasibility of installing carbon capture and sequestration (CCS) at the Lake Charles Power Station. (See *Entergy CEO: Nuclear, Carbon Capture in Equation to Handle Industrial Growth*.)

According to Entergy's application, the large customer "has agreed to pay a capped amount" toward the cost of CCS at the Lake Charles Plant.

Entergy also said the proposed corporate sustainability rider for the customer could offset "a significant percentage of emissions" from the planned natural gas generators.

Finally, Entergy noted that the new gas plants would be "30% hydrogen co-firing with the capability of supporting 100% hydrogen firing in the future with upgrades, and all will have the ability to incorporate a CCS component in the future." The utility said it's also possible it could offer the plants' excess supply in the MISO markets, lowering costs for its customers. ■

NYISO News

NYISO Board Approves RNA, 2025 Budget

The NYISO Board of Directors announced at the Liaison Subcommittee meeting Nov. 19 that it had approved the ISO's 2025 budget and incentive goals. (See *NYISO Updates Stakeholders on Budget, 2025 Goals*.)

The board also approved two items that have been the subject of intense discussion between stakeholders and NYISO this year: the 2025-2029 Demand Curve Reset and the *2024 Reliability Needs Assessment*. (See *NYISO Management Committee Passes 2024 Reliability Needs Assessment*.)

The board was asked whether it had discussed the issue of the RNA's finding that expected large, "flexible" loads, primarily cryptocurrency mining facilities, would eliminate an initially projected statewide capacity shortfall. Several stakeholders had expressed skepticism about that as the RNA made its way through the committees.

Chair Joseph Oates said the board had "engaged" on that topic, but he did not divulge further details. Oates also said some changes to the DCR that came out of stakeholder oral arguments had been reviewed and considered.

"We can't share what we changed; you'll see when we actually make the filing," he said.

Those will come later this month. ■

— Vincent Gabrielle

NYISO control room in Rensselaer, N.Y. | *NYISO*

PJM News

Consumer Advocates File Wide-ranging Complaint on PJM Capacity Market

By Devin Leith-Yessian

Several state consumer advocates filed a complaint at FERC on Nov. 18 alleging that PJM's capacity market is failing to mitigate market power, overestimating future load and producing high clearing prices that generation owners cannot act on.

The complaint asks the commission to find that the 2025/26 Base Residual Auction (BRA) failed to produce appropriate rates, require a host of changes to the auction design and establish a refund with replacement rates. The complaint was jointly submitted by the Illinois Attorney General's Office, Illinois Citizens Utility Board, Maryland Office of People's Counsel, New Jersey Division of Rate Counsel, Office of the Ohio Consumers' Counsel and D.C. Office of the People's Counsel.

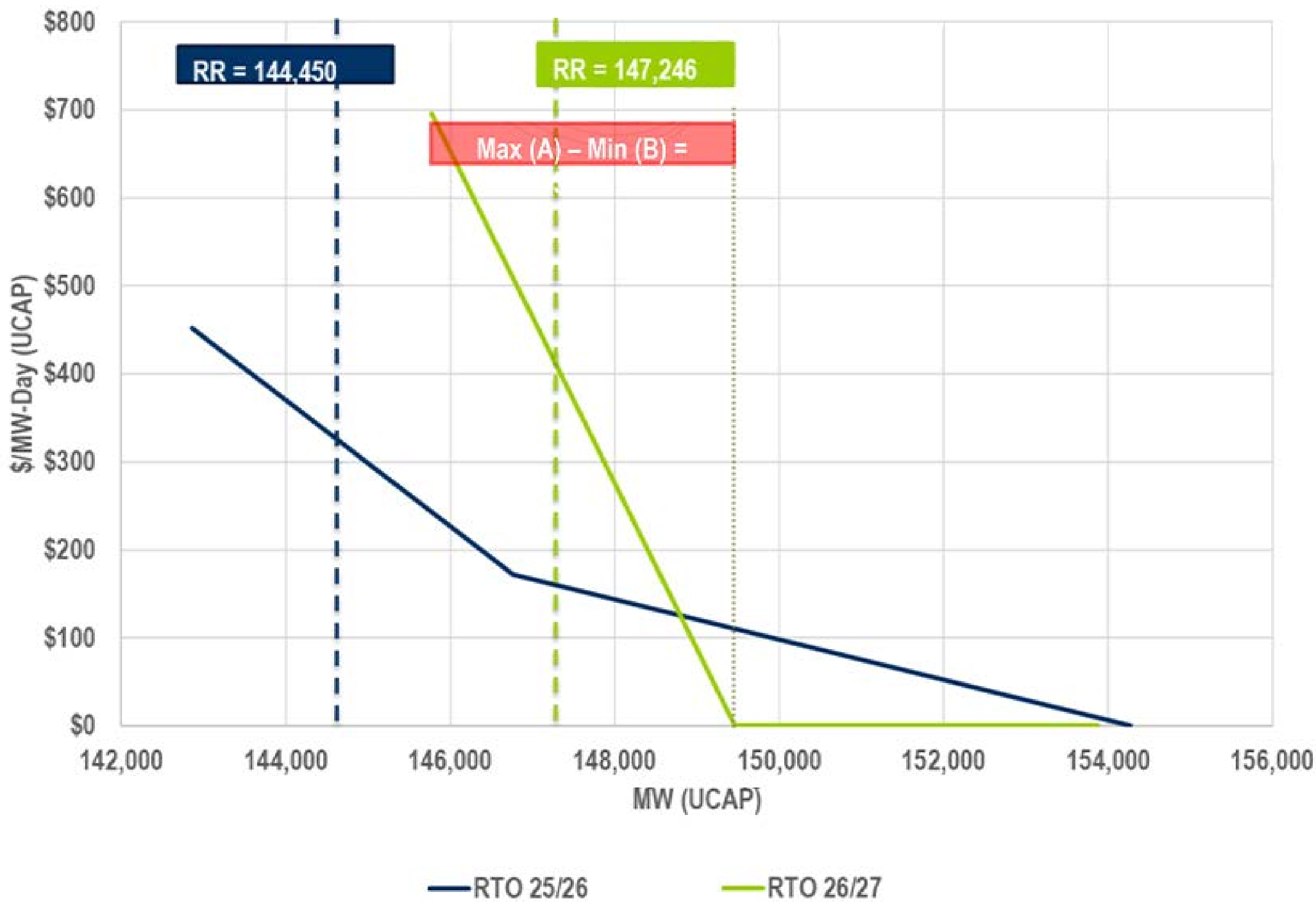
"From one auction to the next, the total capacity cost to consumers jumped from $2.2 billion to $14.7 billion. Worse, continuing to run BRAs using the current design promises the possibility of future auction clearing prices that are even higher. Absent changes to fix the PJM capacity market's flawed auction rules, some have predicted that the 2026/2027 BRA could clear at the new, higher offer cap ($696/MW-day) regionwide, ballooning charges to PJM ratepayers to $37 billion," the advocates said.

One of the market changes they advocated for is already the topic of a separate complaint filed by a group of public interest organizations: PJM's practice of not modeling the expected output of generators operating on reliability must-run (RMR) agreements (*EL24-148*). The retirement of Talen Energy's 1,273-MW Brandon Shores and 702-MW H.A. Wagner generators outside of Baltimore have been credited as one of the drivers of the BGE zone reaching the $466.35/MW-day price cap in the 2025/26 auction.

While the RTO plans to submit a proposal under Federal Power Act Section 205 that would add the output of two generators running on RMR agreements to the supply stack beginning with the 2026/27 auction, the advocates want that change to be made for the prior auction as well. (See "Insight into Upcoming Filing," *FERC Approves PJM Capacity Auction Delay*.)

In addition to requiring that RMR units offer into the capacity market, they requested that the commission extend the advance notice that generation owners must provide PJM ahead of deactivating resources, empower the RTO to delay deactivations for reliability, base RMR compensation on a cost-of-service rate and require that RMR resources participate in all relevant PJM markets.

The advocates wrote that market power



A PJM graphic compares the variable resource rate (VRR) curve for the 2026/27 capacity auction with the year prior. | *PJM*

PJM News

protections are incomplete so long as intermittent generation and storage are exempt from the requirement that all resources must offer into the capacity market and demand response resources are not subject to the three-pivotal-supplier (TPS) market power test. Citing analysis from the Independent Market Monitor on the auction, they said the tight balance between supply and demand led to all capacity resources having market power, underscoring the need to ensure that no resource classes are able to exercise market power. In that analysis, the Monitor has argued that DR and intermittent resources did exercise market power in the auction, a claim PJM has said is unsubstantiated. (See *PJM Market Monitor Releases Second Section of 2025/26 Capacity Auction Report*.)

"The primary cause of the BRA price spike is not the interplay of supply and demand. It is the byproduct of a market power problem endemic to the PJM design that the existing mitigation protocols are unable to address," the advocates wrote.

They requested that DR resources that fail the TPS test be limited to offer caps akin to generation resources; be required to offer their maximum dispatchable demand reduction into the markets; and have their performance measured as a function of the actual metered reduction in load before and after the resource is dispatched.

They also asked that the commission implement the Monitor's recommendation that the capacity ratings for gas generation be applied seasonally to align with PJM's risk modeling. Accreditation for gas resources is capped at their summer ratings, a practice the advocates said is inconsistent with PJM's risk modeling skewing toward the winter. Aligning the two would more accurately reflect their potential contribution to high-risk winter periods.

New supply is unlikely to offer a remedy, the advocates wrote, because of the confluence of a compressed auction schedule and backlogged interconnection queue that make it unlikely that developers can construct resources in response to high prices. In testimony supporting the complaint, Daymark Energy Advisors CEO Marc Montalvo said the high prices serve no benefit for consumers and allow generators to collect windfall revenues. Prioritizing interconnection studies for resources that would be built in constrained locational deliverability areas would allow the resources with the highest impact to be accelerated through the queue, Montalvo recommended.

"Under current market conditions, capacity prices are being driven by the barriers to entry of new supply — including constraints on the time it takes to study interconnection requests and build new transmission to interconnect new resources in the queue — which add to the market power of incumbent suppliers," Montalvo wrote. "High prices cannot bring new generation into the market more quickly than it can be interconnected, and while such prices might retain existing generation, they are substantially above any just and reasonable measure of the net going forward costs that existing resources must cover to deliver capacity."

He went on to argue that the sudden jump in BRA clearing prices — from $28.92/MW-day in the 2024/25 BRA to $269.92/MW-day in the following auction — calls into question whether the underlying fundamentals reflect an abrupt shift from surplus to shortage or a flawed market design.

The advocates also called for FERC to direct PJM to open a stakeholder process to make several changes to the capacity market in the longer term. It singles out the calculation of the net cost of new entry parameter and shifting the capacity market to a prompt or staggered auction to alleviate inflated load forecasts. They argued that PJM has a track record of over-forecasting load, a trend that could be exacerbated by rapidly accelerating estimates of data center load.

"These clearing price outcomes do not match the market facts on the ground. Yes, load is increasing — but PJM has historically overestimated load and appears poised to do so again by exaggerating the likely additions of massive data center loads without firm power supplies," they said. ■

PJM News

PJM Stakeholders Wary of Expedited Interconnection Proposal

RTO Consults Members Committee on RRI, Separate Proposal on Capacity Market Changes

By Devin Leith-Yessian

VALLEY FORGE, Pa. — Stakeholder opinions were sharply divided at the PJM Members Committee's meeting Nov. 21 regarding RTO proposals to allow high capacity factor resources to be speed through the interconnection queue and revise aspects of the capacity market.

The Reliability Resource Initiative (RRI) would advance 50 interconnection requests to Transition Cycle 2 (TC2) — an interim group of queues established as part of PJM's interconnection process overhaul that began last year — in an effort to address a possible resource adequacy gap identified in the 2029/30 delivery year. The proposal would require tariff changes to be approved by the PJM Board of Managers and FERC. (See *Stakeholders Divided on PJM Proposal to Expedite High-capacity Generation*.)

Presenting the RRI, PJM Director of Interconnection Planning Donnie Bielak said the proposal is being brought to address "unique circumstances" and would be a one-time measure to allow uprates and resources that can quickly come online to be expedited through the queue to address a reliability need.

If more than 50 projects are submitted, selection would be based on a scoring formula that awards up to 35 points to projects based on their unforced capacity (UCAP); 35 points for the viability of being in service by June 1, 2029, or sooner; 20 points for higher effective load-carrying capability ratings; and 10 points for site location. The only hard eligibility requirements would be that a project must have a UCAP above 10 MW and that they are not part of a project under FERC Order 1000's State Agreement Approach.

Resources not already subject to the requirement that they participate in the capacity market would be compelled to offer for at least 10 delivery years. Bielak said developers would have the choice of accepting a must-offer requirement for a project they are truly certain can be rapidly brought to market or wait to be sorted into TC1.

TC2 was open to projects sorted into the AG2 and AH1 queues, the latter of which closed in September 2021. Studies on projects submitted after that date are not likely to initiate until 2026.

Responding to stakeholder questions regarding the scale of the impact the RRI could have on TC2 cost allocation, Bielak said PJM does not know which projects will be submitted, and there are hundreds of projects that dropped out of the interconnection process that could be resubmitted. Potential cost allocation impacts vary significantly depending on which projects are submitted and ultimately selected by PJM.

Donnie Bielak, PJM | *© RTO Insider LLC*

Criticisms and Alternatives

Several renewable developers objected to the proposal, arguing it would constitute queue jumping and disrupt network upgrade cost allocation for projects that have been waiting in the queue for years.

Rahul Kalaskar, AES senior director of regulatory affairs, offered an *alternative* from AES Clean Energy and REV Renewables to run TC2 and RRI projects in separate cycles. The RRI projects would be added to the separate cycle, which starts after Decision Point 2 of the TC2 cycle and runs all the studies in one condensed process. Doing so would keep the network upgrades for the TC2 and RRI projects in two different buckets.

Kalaskar said that if PJM's RRI design were to proceed, transmission headroom could be consumed, increasing the costs assigned to TC2 projects and possibly causing some to drop out of the queue.

Steve Lieberman, vice president of transmission and regulatory affairs for American Municipal Power, *said* his organization conditionally supports RRI if changes are made to the scoring weights to prioritize project size and viability; projects that would be part of fixed resource requirement (FRR) plans are excluded; and developers are prohibited from buying out of their obligations.

Tonja Wicks, vice president of regulatory affairs for Elevate Renewables, said "project viability" and the "in-service date" should account for at least half of the project weighting, as it gets to the core issue that PJM is trying to resolve with the RRI: getting capacity that has the most certainty to come online by a set date. Otherwise it risks selecting projects that promise to bring a large amount of power, but with no firm site control or demonstration that they can meet milestones.

Independent Market Monitor Joe Bowring *said* the RRI should be preserved as a permanent option that PJM can deploy when it identifies reliability needs that can be resolved by expe-

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diting new development. Because projects are being fast-tracked to resolve capacity needs, he said the 10-year must-offer requirement should be expanded to the lifespan of the asset.

Mike Cocco, senior director of RTO and regulatory affairs at Old Dominion Electric Cooperative, said data center loads in Northern Virginia are rapidly accelerating, and the RRI is necessary to ensure that PJM can continue to meet that demand. He said ODEC intends to submit projects to be studied under the RRI, possibly including combustion turbine generators, and he encouraged PJM to consider how the milestone deadlines for RRI projects could conflict with timelines for air quality regulations and other requirements.

"We're in a position to bring generation online with the timeline that you're looking for," he said.

Grant Glazer, MN8 Energy's manager of regulatory and market affairs, *highlighted* that projects in TC2 will be studied under a new generation deliverability test, which he said could identify violations prompted by projects in TC1. The status quo rules would assign those network upgrades to TC2 clusters, increasing their cost allocations for up to two-thirds of projects in the cycle. Instead, he encouraged PJM to revise the Regional Transmission Expansion Plan to capture those upgrades.

SIS Eligibility

Along with the RRI proposal, the filing with FERC would include tariff revisions to expand eligibility for projects seeking surplus interconnection service (SIS) by striking language prohibiting projects that could impact the network upgrades for new service customers in the queue.

Stakeholders have argued that the language is overly prohibitive and prevents developers from co-locating thermal resources with renewables and storage.

Sarah Toth Kotwis, RMI senior associate, *said* SIS is the fastest process available for bringing new resources online. Storage co-locating with existing resources can come online within 2.5 years of receiving an interconnection agreement, around half the time for adding new generation.

Wicks said PJM stands alone among RTOs in studying open-loop batteries as discharging in light load cases and using those outcomes to determine whether projects would consume headroom that could be utilized by other queue projects.

"With short duration times for construction and energizing, batteries are the types of resources FERC's SIS directive envisioned utilizing excess capacity — a.k.a. surplus — at existing facilities to meet resource shortfalls and enhance reliability," Wicks said.

PJM CEO Manu Asthana said RTO staff are open to revisiting the light load case test for storage, but that needs to be a discussion in the stakeholder process to ensure there are no unintended consequences. The tariff changes would remove barriers to allow that conversation to proceed.

Asthana said his read on stakeholder impressions on the proposed SIS changes is that PJM is on the cusp of resolving their core concerns about the service. He said PJM is taking that feedback and planning to continue pursuing changes.

"The door is not closed: We want to hear how we can make that work," he said.

Bruce Grabow — a partner in Sheppard, Mullin, Richter & Hampton — urged PJM to take additional time to vet the proposal through the stakeholder process, noting that stakeholders had only a few minutes to make their comments during the meeting, with some rushing to include all of their arguments. That is not how the stakeholder process is supposed to occur, he said.

Because of the lack of discussion, along with his assertion that PJM had still not provided data to stakeholders supporting the need for expedition, the RTO risks protests at FERC and in court, Grabow argued. He asked questions about the weighting system PJM intended to apply to determine which new generation projects would be winners and losers and whether the scoring means would be transparent; when PJM did not provide further detail, Grabow argued that meant the criteria would be subjectively applied, which does not comport with FERC standards of transparency, non-discrimination and preference.

Asthana said there is a need for as many TC2 projects as possible — ideally all of them — to be interconnected. He encouraged members to submit written comments by email, with directions provided in a communication to members. Comments are being accepted through Nov. 27, with staff aiming to submit a filing to FERC around Dec. 9, if the board approves the proposal.

"It felt like people had more to say, and we do want to hear what you have to say," Asthana said.

Proposal to Modify Capacity Market Components

PJM also consulted with the MC at the meeting on a *separate proposal* that would revise the capacity market to include the output of some resources operating on reliability-must-run (RMR) contracts as supply, revert the reference resource to a dual-fuel CT, and remove the reactive compensation component of the energy and ancillary service (EAS) offset. (See "Insight into Upcoming Filing," *FERC Approves PJM Capacity Auction Delay*.)

The 2026/27 Base Residual Auction (BRA) would be the first to use a combined cycle generator as the reference resource, a change that was made in the most recent Quadrennial Review. The higher EAS revenues for CC generators over a combustion turbine unit pushed the net cost of new entry (CONE) value to zero, affecting several parameters derived from net CONE. The variable resource rate (VRR) curve, which defines the slope of the demand curve defining auction clearing prices, would become substantially steeper, and the Capacity Performance penalty rate would fall to zero. (See "Price Cap Increases in 2026/2027 BRA Planning Parameters," *PJM MIC Briefs: Sept. 11, 2024*.)

Even with the change, PJM's Adam Keech said some locational deliverability areas (LDAs) could still see a $0 penalty rate because of the forward price estimates showing a widening spread between gas and electric prices, increasing EAS revenues for all categories of gas generation. The final net CONE will not be known until PJM completes the process of posting the revised planning parameters.

The proposal aims to address those regional impacts by replacing zonal nonperformance charge rates with a uniform penalty derived from the RTO-wide net CONE. Keech said doing so would also reflect the regional emergency capacity deployments PJM tends to experience.

Paul Sotkiewicz, president of E-Cubed Policy Associates, questioned if PJM has examples of dual-fuel CTs being built in the RTO's footprint within the past five years, adding that the necessary air quality permits to run the backup fuel would be almost impossible to get in many areas, particularly in the regions capacity is needed most.

The reference resource has "to be a resource that can be realistically built," he said.

Keech said PJM considered several restrictions that would impact the viability of virtually all technologies and looked for the lowest-cost

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resource that can viably be built. If it were entirely impossible to build a dual-fuel CT across the RTO, the technology would not qualify to be the reference resource, but staff believe there are enough regions where such a unit could be sited to proceed.

Vistra's Erik Heinle, also speaking for Calpine and LS Power, *said* a single-fuel CT would be more appropriate as the reference resource by virtue of being viable to build in a wider range of locations.

Constellation Director of Wholesale Market Development Adrien Ford said CTs are "the pure capacity resource," and setting it as the reference resource would reduce the impact of higher energy revenues on the capacity market.

The inclusion of expected output of generators operating on RMR agreements is aimed at Talen Energy's 1,273-MW Brandon Shores and 702-MW H.A. Wagner generators outside Baltimore. It would only pertain to agreements accepted by FERC by Feb. 6, 2025, and require that the units be able to operate for the entire delivery year; have sufficient run hours to address transmission violations and capacity emergencies; have deliverable CIRs; and be available for dispatch under emergency conditions unless on outage. The changes would be effective for the 2026/27 and 2027/28 delivery years while stakeholders pursue a more permanent approach to how RMR units interact with the capacity market.

Keech said it is not clear that Brandon Shores would be able to operate in accordance with those requirements because of an agreement with the Sierra Club that mandates that the

Adam Keech, PJM | © *RTO Insider LLC*

plant cease coal combustion by the end of 2025, with no plans apparent to convert to alternative fuels. Wagner Unit 3 likely meets all of the criteria, but the RTO is still investigating whether Unit 4 has sufficient run hours to address the transmission needs and be available as capacity.

The RMR units would not be required to take a capacity obligation or enter into BRAs and therefore would not be subject to CP penalties nor included in the balancing ratio. Rather than paying the RMR units as if they had taken a capacity obligation, the proposal would collect capacity revenues and allocate them as credits to consumers assigned a portion of the costs associated with the RMR agreement.

LS Power Vice President of Wholesale Market Policy Dan Pierpont said PJM should ensure that it is considering how the run hours for each of the Talen units may interact. If Brandon Shores cannot operate because of the Sierra Club agreement and Wagner then needs to run more often to resolve transmission violations, that would affect its ability to meet the requirements to be modeled as supply. Keech responded that PJM would address any such interactions.

ACES Power Executive Director of Regulatory Strategy John Rohrbach *said* PJM is currently in a bind where it's likely that the Talen units will run through some avenue — either through a modification to the Sierra Club agreement or an emergency order from the U.S. Department of Energy under Federal Power Act 202(c) — but it does not have concrete knowledge of how the generators will be available. He said that if PJM believes the RMR units will run one way or another, their output should be modeled.

The third prong of PJM's proposal — to remove compensation for generators providing reactive service from the EAS offset — is in line with a FERC order finding that consumers cannot be charged for reactive service within a standard range (*RM22-2*). The commission's Oct. 17 order provided PJM with additional time to submit a compliance filing to effectuate a transition mechanism to eliminate reactive service, but it also required a separate filing to address how it is reflected in the EAS offset.

The proposed change would be a severable component of the filing, allowing FERC to approve or deny it separate from how it rules on other aspects of the proposal. (See "PJM Details Path Forward on Reactive Power," *PJM MIC Briefs: Nov. 8, 2024*.) ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse CIR Transfer Proposal

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee on Nov. 21 voted to endorse a *proposal* to create an expedited process to study interconnection requests that would reuse the capacity interconnection rights (CIRs) of a deactivating resource.

The tariff revisions, proposed by East Kentucky Power Cooperative and Elevate Renewable Energy, were approved with 77% sector-weighted support and added to the Members Committee's consent agenda, which also passed during the committee's meeting later that day. (See "CIR Transfer Proposal Discussed," *PJM MRC Briefs: Oct. 30, 2024*.)

Under the proposal, PJM would study replacement resource requests in parallel with projects sorted into the standard interconnection queue with the aim of offering developers an interconnection agreement on an eight- to 10-month timeline. To minimize impacts on queue timelines, CIR transfers would be studied using the most recent phase 2 or 3 grid model developed for queue clusters.

The process could be initiated within one year of a formal deactivation notice being received. The replacement resource would be required to interconnect at the same substation and voltage as the original resource, though it could be physically located elsewhere so long as it ties in at the same point. The maximum facility output and CIRs would have to be equal to or lesser than the deactivating generator.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said the proposal would allow developers to take advantage of transformers and other infrastructure already in place to avoid supply chain issues causing delays to construction across the U.S.


PJM's Peter Langbein | © *RTO Insider LLC*

"This is something that helps avoid some of the supply chain issues to get resources on quicker," he said.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said his members were divided on the motion, with some supporting it as an improvement that would speed development. Others are concerned that interconnection would remain too slow, in part because of the ability for generation owners to wait a year before transferring CIRs, and preferred a design the Independent Market Monitor offered during deliberations at the Planning Committee. If the MRC had not endorsed the proposal, Poulos said some advocates intended to move the Monitor's proposal as an alternative.

The Monitor's package would have prohibited bilateral exchange of CIRs and instead created a PJM-administered process to shift headroom from retiring resources to any project in the queue or proposed by a developer that could resolve transmission violations associated with that deactivation.

A third proposal sponsored by PJM at the PC was closer to the endorsed proposal — allowing CIRs to be traded after a deactivation — but would have imposed tighter eligibility limits, including outright barring storage, and required that any replacement resources that prompted network upgrades or would consume available headroom be removed from the expedited process and directed to submit an application to be studied under the wider queue.

The language endorsed by the MRC and MC would allow projects with network upgrades to proceed so long as they cover associated costs. Developers would also be permitted to reduce the scope of a project to avoid network upgrades before proceeding.

The EKPC-Elevate proposal received 51.8% support at the PC during the Oct. 8 vote, while PJM's design received 40.6% and the Monitor's received 11.1%.

Monitor Joe Bowring said he does not believe the expedited process would be an improvement, and PJM would continue to face challenges attracting new entry. He suggested it should expand its Reliability Resource Initiative to be retained as a long-term tool to speed

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interconnections when reliability issues are identified. The initiative — an in-development, interim accelerated interconnection process — would open 50 slots for high capacity factor projects to be added to Transition Cycle 2, allowing them to be studied in advance of projects that have yet to receive a queue position.

He argued that a private, bilateral CIR trading process would introduce delays and create market power for holders of existing CIRs. Owners of deactivating assets would be able to pick the highest bidder for the replacement resource, rather than PJM being able to select the projects that would have the highest impact. Intermittent and storage replacement resources would also not be required to offer into the capacity market, meaning they may not provide the reliability benefit PJM is seeking through the process.

Third Phase of Hybrid Resource Rules Endorsed

Stakeholders endorsed by acclamation a *proposal* to implement the third phase of PJM's hybrid resource rules, expanding the model to include non-inverter-based generation paired with storage.

The language is slated to be voted on by the MC on Dec. 18. (See "1st Read on 3rd Phase of Hybrid Resource Rules," *PJM MRC Briefs: Oct. 30, 2024*.)

Participation in the energy and ancillary service markets would be along the lines of the Energy Storage Resource Participation Model detailed in Manual 11; capacity accreditation would focus on the storage element of the resource while taking into account the availability of the generation component.

Hybrids with any component subject to the requirement that resources offer into the capacity market would also be subject to the must-offer rule. Hybrids with no component subject to the rule, such as intermittent generation or storage, would not be mandated to participate in the market.

PJM's Maria Belenky said a friendly amendment was offered following the first read in November to align the binding notice of intent requirement for hybrids with other resource classifications. She said stakeholders pointed out that a different timeline would exist for hybrids than all other planned resources under the original tariff language drafted.

First Read on Quick Fix for Revising Load Drop Estimate Inputs

PJM's Andrew Gledhill presented a *proposal* to grant PJM more flexibility to reflect errors in the availability of load management when calculating the unrestricted peak loads component of the load forecast.

The revisions to PJM Manual 19: Load Forecasting and Analysis are being brought as a quick fix — allowing the *issue charge* and solution to be voted on concurrently — in an effort to have the changes effective for the 2025 load forecast.

Gledhill said the change is intended to account for instances when load management deployments occur at times that participants are operating below their peak load, which would reduce the estimated load drop PJM is likely to receive. That includes holidays when industrial consumers are likely to already be offline.

If starting with the premise of peak load contribution rather than what the actual loads would be at that time, Gledhill said it is likely that inaccurate information would be included in the forecast.

PJM's Pete Langbein said that historically, peak loads were concentrated on hot summer days, but the RTO's risk modeling has shifted the focus toward winter deployments, when the energy reduction capability can vary more significantly. Load drop estimates are used to calculate unrestricted load for forecasting, capacity compliance and the addback reported to the utility for the following year. The hourly forecasts are also an input into the effective load-carrying capability models used in resource accreditation.

Manual Revisions to Clarify DASR Calculation for 30-minute Reserves

PJM's Kevin Hatch presented *revisions* to Manual 13 to document how the day-ahead scheduling reserve (DASR) is used to determine when the 30-minute reserve requirement may be insufficient for procuring adequate reserves.

The Operating Committee endorsed the language as a quick-fix proposal during its Nov. 8 meeting. (See "Stakeholders Endorse Quick Fix Solution on Day Ahead Scheduling Reserve Calculation," *PJM OC Briefs: Nov 8, 2024*.)

The 30-minute reserve is set at the greater of 3,000 MW, the primary reserve requirement or the largest active gas contingency, which Hatch said does not reflect the full range of operational risks dispatchers must account for when determining necessary reserves. The DASR calculation accounts for load forecast error and forced outage rates, both of which were factors that PJM sought to include in a dynamic 30-minute reserve formula stakeholders rejected in July. (See "Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility," *PJM MRC Briefs: July 24, 2024*.)

Hatch said the revisions reflect an existing practice and no changes are being made to PJM processes.

Manual 14D Periodic Review

PJM's Madalin How presented a package of *revisions* to Manual 14D drafted through the document's periodic review. The changes would correct grammatical errors and typos, and update communication protocols, including adding a new email address.

The manual would also be updated to document that generators must provide reactive capability curves to PJM before they can come online and that reactive testing must be completed within 90 days of initiating commercial operations.

Members Committee

Comment Period Opens on Cost Allocation Tariff Revisions

PJM told the MC that the Transmission Owners Agreement Administrative Committee had opened a 30-day consultation period on *revisions* to tariff Schedule 12, which details the solution-based distribution factor (SBDFAX) process for allocating the costs of Regional Transmission Expansion Plan projects (*EL21-39*, *ER22-1606*).

The revisions would address a FERC order granting a complaint from the Long Island Power Authority and Neptune Regional Transmission System regarding components of the SBDFAX method.

Merchant transmission facilities would be considered "responsible customers" within the zone they are interconnected to be assigned a portion of the transmission enhancement charges associated with RTEP projects. If material modifications are made to the boundary of that transmission zone, merchant transmission owners would have the option to have the DFAX analysis separated from that zone.

Required transmission enhancements approved by the PJM Board of Managers prior to Dec. 11, 2023, will be located in the zone of the relevant TO, while enhancements approved after that date would be located in the zone where the physical enhancements are sited. ■

— *Devin Leith Yessian*

SPP News

FERC Rules Against SPP Multiday Commitment Proposal

In Separate Ruling, Commission Upholds RTO's Cost Allocation Method

By Tom Kleckner

FERC on Nov. 21 rejected SPP's proposed tariff revisions to implement a multiday economic commitment (MDEC) process, saying it introduces a potential gaming opportunity (*ER24-2520*).

The commission agreed with the RTO's Market Monitoring Unit that long-lead resources, such as coal plants, could intentionally lower their market offers below their actual costs to gain an out-of-economic-merit order and then receive a make-whole payment to which they would not otherwise be entitled.

"SPP's proposal would allow certain resources to unreasonably shift the risk that their costs are not recovered exclusively to customers, potentially leading to both inefficient market outcomes and gaming opportunities," FERC said.

The commission also said SPP had not adequately supported its assertion that its "analysis shows that [the proposed MDEC process has] the potential to create economic benefits to the market." It said the RTO did not provide any information about the analysis or a "reasoned explanation" that showed the MDEC process would lower total production costs.

"It is not clear how SPP's proposal would result in a lower-cost commitment solution because long-lead resources could appear cheaper to the market than they really are, potentially displacing lower-cost resources and driving up market costs with no benefit to the market," the commissioners wrote.

SPP had argued that the proposed MDEC process would improve the methods by which long-lead resources, which account for about 34 GW of available energy, participate in SPP's market. Currently, they cannot be committed in the day-ahead market, instead normally opting to self-commit as price takers. However, the increased prevalence of less expensive renewable and natural gas units has made coal units increasingly less economical to self-commit.

Several public interest organizations protested SPP's proposal, saying it would require the RTO to evaluate the economics of issuing commitment instructions to long-lead resources by comparing the expected production cost impacts of committing them before the day-ahead market closes using the real-time balancing market's offers for all resources.

"There was absolutely no evidence that the process proposed by SPP would actually work to reduce the uneconomic dispatch of coal resources in the market," Earthjustice attorney Aaron Stemplewicz, who represented several public-interest groups in the proceeding, told *RTO Insider* via email. "The commission was correct to flag that it merely shifted risk from generators to the market and could easily have been manipulated to be a handout for uneconomic coal-burning power plants and other long-lead resources."

FERC's order was without prejudice, allowing SPP or other grid operators to propose different MDEC processes.

John W. Turk Jr. coal plant | *Oklahoma Municipal Power Authority*

Cost-allocation Ruling Reaffirmed

FERC also rejected rehearing requests and sustained its previous approval of SPP's tariff revisions allowing certain transmission facilities' costs to be entirely allocated on a regional postage-stamp and cost-by-cost basis (*ER24-1583*).

The commission modified its original order but reached the same result it did in May, when it found SPP's capacity, flow and benefit analyses of the Sunflower Electric Power transmission facilities at the center of the proceeding provided benefits to the region as a whole. (See *FERC Approves SPP's Cost-allocation Revisions*.)

Several SPP transmission owners and municipal utilities and the Louisiana Public Service Commission filed rehearing requests of FERC's order. They contended that the commission did not conduct the necessary cost-causation analysis and misapplied the "roughly commensurate rule" because it did not require a more granular, zone-by-zone benefits analysis of SPP's proposal.

FERC dismissed those arguments, along with others that claimed the commission failed to show that SPP's capacity, flow and benefit criteria are linked to cost causation and that the order is "impermissible retroactive ratemaking."

Commissioners Mark Christie and Lindsay See filed separate concurring opinions, with both concurring only in the result of the proceeding and agreeing that the deciding factor for them was the support of the SPP Regional State Committee, which "has historically had a unique and authoritative role representing the states in SPP," Christie said.

"For me, the RSC's unique role in representing the SPP states in difficult cost-allocation matters like these resolves this close case on the side of approval," See wrote.

In a Nov. 20 letter order, FERC also accepted SPP's tariff revisions to calculate real-time balancing market (RTBM) prices should the system fail for more than 12 dispatch intervals and to extend the notification period for price corrections (*ER25-71*).

The grid operator will use the day-ahead market's LMPs, marginal congestion components and marginal loss components for RTBM settlements. The mechanism will accurately reflect prices had the RTBM system results not been able to calculate LMPs.

The notification period is extended from five calendar days to five business days. ■

SPP Has ‘Positive Outlook’ Heading into Winter

By Tom Kleckner

SPP says it expects to have enough generation to meet demand this winter following an assessment that indicated an increase in operational certainty over the previous two assessments.

The grid operator’s staff told stakeholders Nov. 18 during its annual Winter Reliability Forecast and Emergency Communications webinar that they project a 98.5% probability of SPP having sufficient resources to meet the projected peak demand this winter season. That probability increases further when operating reserves are added to the mix.

Weather forecasts, peak demand projections, expected generation availability and other trends suggest the region will have a greater margin between electricity demand and generating capacity than in the previous two peak seasons, staff said.

“While this forecast presents a positive outlook for electricity customers throughout the SPP footprint, we must continue to be vigilant and plan for growing power demands in the future,” SPP COO Lanny Nickell said in a statement. “We can never say for sure when extreme weather events, such as what we have experienced in recent years, may materialize. SPP is doing everything it can to be prepared to meet customer needs.”

Winter storms in February 2021 and December 2022 stretched the footprint’s available reserves, forcing the RTO to shed load in 2021 and import power.

SPP has projected demand to peak at 46.92 GW in its 14-state footprint. It has a total winter capacity of 63.88 GW, resulting in about a 40% reserve margin. The capacity values do not include the effect of accreditation policies filed at FERC. The grid operator’s resource adequacy requirements for the winter season (December-March) are not effective until the 2024/25 winter season.

The La Niña weather pattern is forecast to return during the upcoming season, bringing with it the potential strong polar jet stream that led to the 2021 and 2022 winter storms. Temperatures are expected to be lower than normal in the northern plains and higher in the South.

SPP annually assesses historical and predicted future electricity use, weather forecasts, wind energy’s variability, drought conditions, and generation and transmission outages to identify and address threats to energy reliability during the winter. ■

SPP says its expects to have enough generation to dispatch and meet demand in its 14-state footprint this winter. | *SPP*

SPP News

Markets+ ‘Alert’ Covers CAISO’s Dual Roles as Market Operator, BA

ISO Says It Manages ‘Multiple Responsibilities’ with ‘Integrity, Transparency’

By Robert Mullin

CAISO will be inherently compromised in its role as an operator of a deeper Western market because of its conflicting responsibilities as balancing authority within that market, a group of entities that support SPP’s Markets+ over the ISO’s Extended Day-Ahead Market (EDAM) argue in their latest “issue alert.”

“An organized market that lacks a fully impartial market operator exposes its participants to shifts in hundreds of millions of dollars of economic value, shifts in reliability risk and shifts in environmental benefits because of the actions that the market operator takes or does not take,” the “joint authors” wrote in *the Nov. 14 alert*, the sixth in a series of seven such pieces touting the benefits of Markets+.

The contributors include Arizona Public Service, Chelan County PUD, Grant County PUD, Powerex, Public Service Company of Colorado, Salt River Project, Snohomish PUD, Tacoma Power, Tri-State Generation and Transmission Association and Tucson Electric Power — all of whom helped fund the Phase 1 development stage of Markets+.

The latest alert is possibly the most technically complex because it focuses on the multi-layered processes CAISO uses to manage operations in its real-time Western Energy Imbalance Market (WEIM), which has grown to cover more than 80% of load in the Western Interconnection since being launched in 2014.

“Over the past decade, in its [emphasis theirs] *commingled roles as a balancing authority, transmission service provider and market operator*, the California ISO has taken a range of actions and operational decisions *for the benefit of the California ISO’s Balancing Authority Area and/or transmission service territory* that significantly impact market outcomes for all participants,” the authors write.

In an email to *RTO Insider*, CAISO spokesperson Anne Gonzales said the ISO is “proud of the integrity and transparency with which we have managed our multiple responsibilities and the many trusting partnerships we have built with balancing authorities, policymakers and other stakeholders across the West” in operating the WEIM.

CAISO’s dual roles in the WEIM have become a recurring point of debate in the competition between Markets+ and the EDAM, particularly in discussions around the Bonneville Power Administration’s day-ahead market participation decision process. (See *Rising Tensions Evident at BPA Day-ahead Markets Workshop*.)

In the Nov. 14 alert, the joint authors zero in on four complaints from the Markets+ camp regarding CAISO’s operational practices in the WEIM.

Load Conformance

The first of those complaints deals with the WEIM market process known as “load bias” or “load conformance,” which allows a BA to adjust its demand forecast in the hour-ahead scheduling process (HASP) and 15-minute market (FMM) to better position itself for a real-time interval.

The alert contends that as a BA in the WEIM, CAISO has a history of making unusually large upward adjustments to its demand forecasts during morning and evening peak hours “to acquire flexible capacity through additional energy imports rather than explicitly purchasing flexible capacity itself.”

The authors say that while load conformance is available to all WEIM participants, CAISO’s “very large and systemic upward-load biasing” for its territory “appears to be unique.”

As an example, the alert points to a period during a July 2023 heat wave in which CAISO’s average load bias in the FMM during the evening peak was about 1,800 MW but reached as high as 5,000 MW.

“This is a continuation of an ongoing pattern of load biasing for the California ISO service area that first began in 2017,” the alert argues. It adds that “consistently intervening in the WEIM through manual operator adjustments that do not reflect actual system conditions” is likely to increase production costs and market prices in ways that don’t reflect marginal costs, while signaling that market design elements such as the WEIM’s Resource Sufficiency Evaluation (RSE) and flexible ramping product are inadequate to ensure reliability.

The authors also point to a previous statement by CAISO staff that load conformance is “significantly used” by the HASP and FMM “to position resources and secure additional intertie capacity.” But in *a 2022 analysis* that examined the issue, CAISO said it found “no evidence that load conformance causes a one-to-one increase” in WEIM transfers into the ISO.

> **Why This Matters**
>
> CAISO's dual roles as both the operator of the WEIM/EDAM and its largest participant have taken on increasing importance in the debate between EDAM and Markets+ supporters.

It also found that use of load conformance does not improve CAISO’s ability to pass the WEIM bid range capacity and flexible ramping tests, but instead reduces the ISO’s ramp capability, making it more difficult to pass the flexible ramping test.

“The concern that load conformance could create more headroom on CAISO resources by unloading internal resources with increasing transfers was not validated,” the ISO said.

In an interview with *RTO Insider*, CAISO Director of Market Analysis and Forecasting Guillermo Bautista Alderete said the load conformance actions cited in the alert actually comes with a cost for the ISO.

Alderete said when CAISO applies load conformance in the HASP, FMM or real time, it effectively increases the ISO’s demand requirement.

“That has an effect that is going to dispatch supply up, and the consequence is that the prices are going to reflect that,” he said. “So when we clear the real-time market, the clearing prices are already reflecting the need — that we have asked for additional requirements to clear. It doesn’t come for free, because now the CAISO area — CAISO load — has to pay higher prices because of the consequence of having this load conformance,” which also translates into higher prices paid to exporters into the ISO.

WEIM Transfers

The alert’s second complaint refers to CAISO’s blocking of WEIM transfers “to support California’s reliability.” The alert points specifically to a period over July-November 2023 when the CAISO BAA blocked import transfers from the WEIM in the HASP and FMM — but not in real-time — during net peak load hours.

As the authors note, CAISO’s Department

SPP News

of Market Monitoring (DMM) later said "the transfer limitation had the intended effect of increasing hourly block imports into the CAISO area and decreasing hourly block exports out of the CAISO area to protect reliability during peak net load hours in late July through mid-August."

The DMM also determined the practice "created a significant, systematic modeling difference between the 15-minute and five-minute markets, which impacted market results in several ways," including increasing congestion into the CAISO area from other WEIM areas in the FMM compared with the real-time market, lowering the WEIM's FMM prices relative to real time in the Desert Southwest and reducing the amount of energy that could be scheduled out of the Southwest in the HASP and FMM.

"While causing adverse consequences across the market footprint, these California ISO operator actions may not have been effective at enhancing reliability in the California ISO's service area, as DMM found that '[u]nder most conditions, it seems that limiting transfers would not provide significant reliability benefits, but would have negative market impacts," the alert notes.

The joint authors expressed concern that the import limits continued even after initial reliability concerns of late July and early August had passed and by "a lack of transparency" that they were even occurring, saying the first mention by CAISO was in mid-September almost two months after they began.

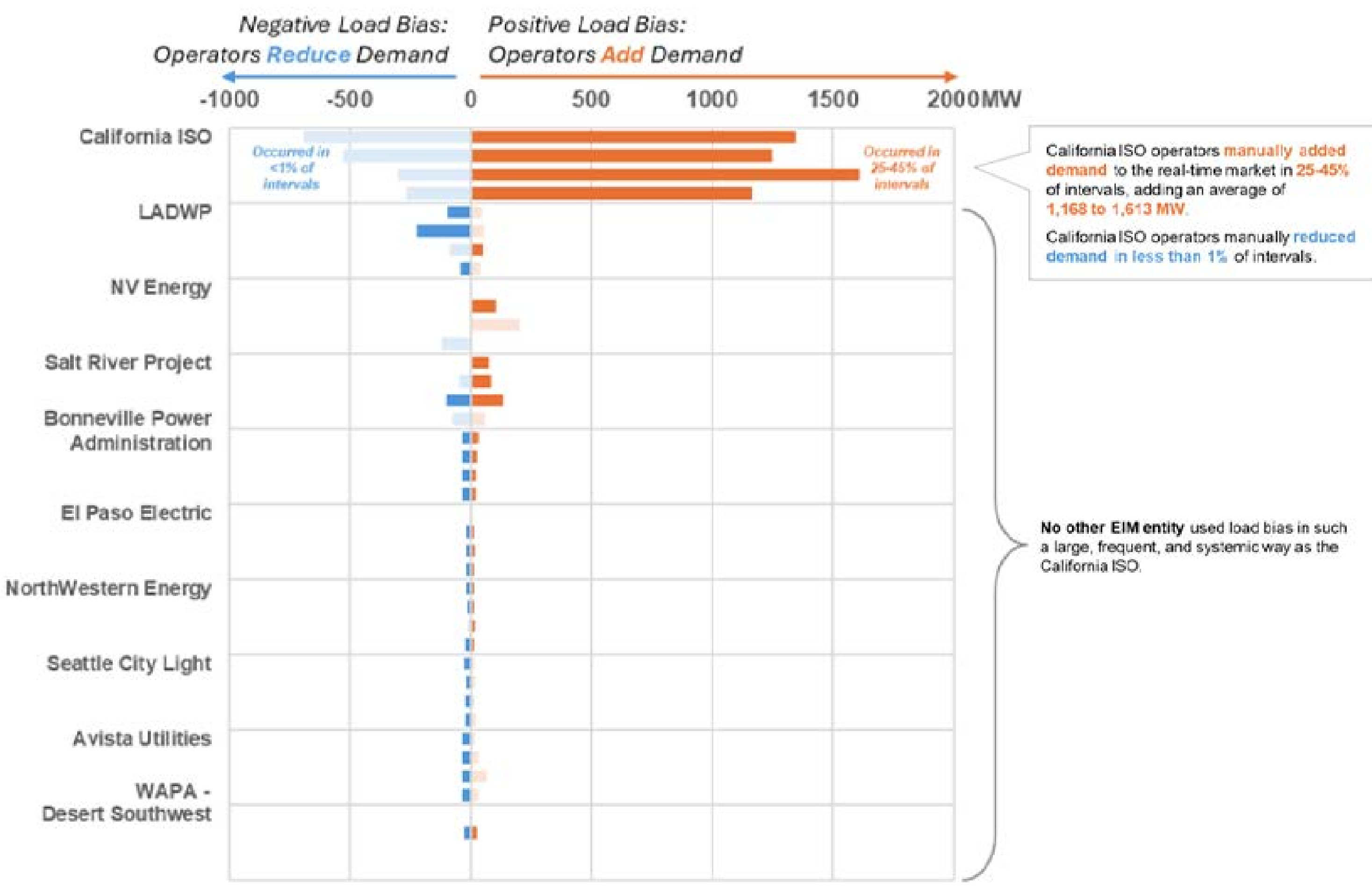
In a May 2024 *presentation* to the CAISO Board of Governors and Western Energy Markets Governing Body, the ISO explained that the ISO started the limits after large volumes of WEIM transfers scheduled in the HASP began failing to materialize in real time.

Alderete said a "key piece of information that is typically neglected" is that CAISO was attempting to reduce its reliance on WEIM imports in response to the market behavior.

"We were limiting ourselves to not rely too much on the EIM transfers because from the operational point of view, we wanted to be as clear as possible [about] how much internal supply we could have available to meet our own needs. We were insulating ourselves — basically isolating ourselves — from the rest of the EIM market," he said.

Alderete said the ISO ceased the practice in November 2023 after it fixed three market issues, including inaccurate display of dispatchable capability in the WEIM, scheduling and tagging processes that allowed participants to ignore export reduction and inconsistent treatment of intertie transactions among BA that increased congestion.

"Limiting the transfers is one of the tools that any balancing area participating in the market has, including ... CAISO. We are not the first



The sixth "issue alert" from Markets+ supporters contends, among other things, that CAISO engages in a practice of biasing its WEIM load forecasts sharply upward in ways not matched by other market participants. | *Markets+ Joint Authors using CAISO data* one to use it; we are not the only one using it," he said.

'Limited Transparency'

The alert reprises another common contention by Markets+ supporters: that CAISO can't be trusted to fairly manage the WEIM's Resource Sufficiency Evaluation (RSE), which is the market test run ahead of every delivery interval to ensure all participants are making enough capacity available to avoid leaning on the market to meet their energy needs.

They contend that WEIM participants have "limited transparency" into CAISO's specific inputs and calculations when applying the RSE, which was "routinely failing to identify instances in which" CAISO's own area didn't have sufficient resources.

"Even in hours that the California ISO declared an energy emergency, such as during the August 2020 and September 2022 heat events, the RSE still frequently allowed the California ISO area to 'pass' the RSE," the authors say.

This points to a larger problem with the RSE, according to the authors: that a resource-deficient WEIM participant is allowed to continue importing the amount of energy it was importing during a previous interval in which is passed the test, without facing an additional financial penalty. They say the rule is "uniquely beneficial" for CAISO because, unlike other WEIM entities, "it typically begins importing large quantities from the rest of the WEIM in the hours leading up to the afternoon peak, driven in part by the large quantity of upward load bias applied by CAISO operators."

"This is very different from other WEIM entities that are often importing very little (or even exporting) immediately prior to an RSE failure. Those entities face much more significant limitations on their ability to access WEIM imports without financial penalty," the alert says.

Alderete countered that RSE rules apply in a uniform way to every BA across the WEIM, including CAISO, and that the ISO has been "very transparent about the design features of that model" and has in recent years undertaken a series of stakeholder policy initiatives to refine the mechanism.

He also said it was "misleading" to contend CAISO faces no financial penalties for failing the RSE, adding that the ISO soon will publish an analysis showing how it did incur such penalties during the past summer.

Congestion Rent Debate Continues

The alert concludes with criticism of CAISO's treatment of congestion revenue rights (CRR) in its market, a subject that became a kind of proxy for the debate between Markets+ and EDAM supporters after a January 2024 cold snap triggered energy emergency alerts in BAs throughout the Northwest because of supply shortages. (See *NW Cold Snap Dispute Reflects Divisions over Western Markets*.)

During that event, the authors note, CAISO collected high transmission congestion rents on power flowing across the Pacific AC Intertie (PACI), which is jointly operated by CAISO and entities in the Northwest, but distributed congestion revenues it collected only to its own participants and CRR holders.

"[T]he coordinated physical capability of the multi-state transfer path is modeled by the California ISO using a 'scheduling constraint' that is applied as a limitation on the quantity of energy that can be imported into or exported out of California," the alert states. "California ISO's choice to model the coordinated limit of the overall multi-state transfer path as a limitation 'inside' the California ISO ensures the congestion revenue associated with the overall multi-state path is collected and allocated back to [sic] exclusively to customers of the California ISO."

The authors say a "similar dynamic" of rent allocation has played out during summer heat waves when CAISO has imported power from the Northwest.

CAISO contested the Markets+ supporters' assessment practices during a CRR "myth-busting" presentation to the WEIM's Regional Issues Forum in September. (See *CAISO Seeks to Dispel CRR 'Myths' Around January Cold Snap*.)

And in his interview with *RTO Insider*, Alderete repeated an argument CAISO has raised previously: that the ISO is the only day-ahead market that provides a market solution to manage congestion, which occurs only south of the "constraint."

"There is no price signal for doing congestion management in the other northern part of the constraint. That is the problem when you don't have a market on the other side. There is no mechanism to be able to dispatch, to move resources, to [do] price congestion. All that is basically manually done," he said.

The joint authors' seventh and final issue alert will cover "durable customer benefits." ■

Company Briefs

GE Vernova Fires Workers Following Blade Failure Probe

GE Vernova confirmed it has fired a number of personnel from its LM Wind Power factory in Gaspé, Canada, following its investigation into a July blade failure at the 806-MW Vineyard Wind array.

A GE spokesperson said the company "commenced an extensive internal review of our blade manufacturing and quality assurance program across our offshore wind operations following the July blade event at Vineyard Wind. During the review we determined that the quality controls in our Gaspé factory did not meet our expectations. As a result, several weeks ago we implemented corrective actions at our blade facility in Gaspé, which included impacts to processes and people."

The company added that a "small number" of employees, including some senior level plant supervisors, were terminated or suspended because of the findings.

More: *Renews*

US Army Corps Approves Eco Wave Power Permit for Onshore Wave System

Eco Wave Power secured the final permit from the U.S. Army Corps of Engineers to install its first onshore wave energy system in the U.S. at the Port of Los Angeles.

The permit allows Eco Wave Power to install eight wave energy floaters on the existing concrete wharf at Municipal Pier One. The setup will include an energy conversion unit housed in two 20-foot shipping containers. The floaters will convert the rising and falling motion of the waves into energy.

Eco Wave Power plans to complete the installation in early 2025.

More: *Electrek*

NRG Energy, Renew Home Select Texas for 1-GW VPP

Renew Home and NRG Energy announced their intention to create a 1-GW virtual power plant in Texas by 2035, which would be the biggest in the country.

Under the new program set to launch in 2025, Renew Home and NRG are hoping to offer no-cost installations of Nest and Vivint smart thermostats. To get a free thermostat, customers must choose from a variety of rate plans and incentives that allow the companies to shift their power use. Renew Home estimates that 8.5 million homes could yield 8.5 GW of "load-shift potential" for ERCOT.

Renew Home was formed last year by the merger of Google Nest's smart-thermostat energy-shifting service Nest Renew and Ohmconnect, a startup with hundreds of thousands of residential demand-response customers.

More: *Canary Media*

Federal Briefs

Biden Nominates 2 to TVA Board

President Joe Biden last week announced his intent to nominate Beth Harwell and Brian Noland to the Tennessee Valley Authority Board of Directors.

Harwell has been serving as a member of the TVA board since 2021.

Noland, the president of East Tennessee State University, has served as a board member for the American Council on Education, the American Association of State Colleges and Universities, the NCAA Division I Board of Directors, Ballad Health, Bank of Tennessee and the TVA.

More: *The White House*

Electrical Failures Knocked All TVA Nuclear Plants Offline in 2024

Electrical equipment failures temporarily knocked out all three of the Tennessee Valley Authority's nuclear power plants in 2024.

The equipment failures at the Sequoyah, Browns Ferry and Watts Bar nuclear plants led to what TVA classifies as forced outages, meaning operators cannot plan more than 10 days in advance for a unit to go offline. One forced outage included the failure of a main generator at Sequoyah that will cost $82 million to replace and will not be online again until 2025.

TVA plans to submit license renewal applications for each of its nuclear plants.

More: *Knoxville News Sentinel*

State Briefs

FLORIDA

PSC Staff: FPL Should Charge Customers for Storm Costs

Public Service Commission staff last week recommended that Florida Power & Light should be allowed to make up about $1.2 billion by temporarily charging an add-on to customers' bills to cover costs related to hurricanes Debby, Helene and Milton.

Under FPL's proposal, average customers would see their monthly bills go from $121.19 a month to $133.99 in January 2025.

The PSC is scheduled to take up the request Dec. 3.

More: *WFOR*

MAINE

Portland City Council Votes to Establish Climate Action Fund

The Portland City Council unanimously voted to establish a municipal climate action fund, which was recommended by city staff and the council's finance and sustainability and transportation committees.

The ordinance establishing the fund allows spending both on initiatives to “advance strategies in One Climate Future” and to fund costs of operating the sustainability office including “staff salaries, interns, public outreach and engagement, professional development, software licenses or subscriptions.” One Climate Future is a shared climate action plan for the cities of Portland and South Portland that lays out a plan for reducing contributions to climate change.

The council later approved a spending cap of $125,000 for staff salaries.

More: *Portland Press Herald*

MARYLAND

BPW Approves Permit to Expand Pier for OSW Development

The Board of Public Works last week unanimously approved a permit to expand the 353-foot Sinepuxent Bay pier in West Ocean City that will support US Wind’s plan to build its offshore wind project.

The pier is currently used by local fishers.

US Wind plans to build a 114-turbine, 2-GW wind farm 8 miles off the coast of Ocean City.

More: *Maryland Matters*

Climate Commission Tables Debate on Revenue-generating Measures

The Commission on Climate Change last week delayed a decision on adopting aggressive revenue-generating measures to fund programs that confront climate change until next month.

The commission is putting the finishing touches on its annual list of recommendations for Gov. **Wes Moore** and lawmakers to consider for the state’s ongoing attempts to meet climate mandates. The report includes recommendations that the state authorize a cap-and-invest scheme to make the transportation and building sectors pay for carbon emissions, establish a fossil fuel transport fee and mitigation fund, and make large fossil fuel companies compensate the state for climate emissions and associated environmental degradation.

The document is scheduled to be finalized Dec. 12.

More: *Maryland Matters*

MICHIGAN

Municipalities Challenge State’s New Clean Energy Zoning Law

In a claim filed with the Court of Appeals, 72 townships and seven counties argued against a new state law that places the permitting for renewable energy projects under the control of the Public Service Commission.

Opponents of the law have argued that it takes the permitting process away from local governments and violates the Administrative Procedures Act, which dictates the rulemaking process for state agencies, among other things.

While the law requires energy companies to work with localities whose permitting process matches the state’s, utilities can submit a permitting application to the PSC for several reasons, including the impacted community failing to approve or deny an application in a timely manner.

More: *Michigan Advance*

MINNESOTA

Phase 1 of Sherco Solar Plant Completed

Xcel Energy last week announced its Sherco Solar plant has completed Phase 1 of its three-phase development.

The facility now generates 220 MW and consists of 500,000 panels but is expected to triple to 1.5 million panels by 2026.

More: *WCCO*, *KSTP*

NEW HAMPSHIRE

PUC Leaves Net Metering Rules Unchanged, Will End in 2040

As order from the Public Utilities Commission made no substantive changes to the state’s net metering program.

Most notably, the order does not extend the termination date of the program that was established in a 2017 PUC order, which will be at the end of 2040. However, the PUC said it will “establish further process to consider additional changes to the net-metering tariff as part of the commission’s ongoing obligation to develop and improve net-metering tariffs in New Hampshire.” In a supplemental order, it set a February 2025 meeting to start the process.

More: *Concord Monitor*

NEW JERSEY

BPU Approves Gas Rate Hikes

The Board of Public Utilities last week approved rate increases for New Jersey Natural Gas and Elizabethtown Gas.

The average New Jersey Natural Gas customer can expect to see their bill rise by $23.94 (15.8%) per month. Elizabethtown Gas Company customers will see a monthly increase of $9.43 (6.5%).

Board officials lamented the increases but said they are necessary to fund infrastructure upgrades to prevent gas leaks and other problems.

More: *New Jersey Monitor*

NORTH CAROLINA

Duke to Retire Gaston County Coal Plant, Replace with Battery Storage

Duke Energy plans to shutter and demolish its Allen coal-fired plant and replace it with battery storage.

Duke said it will initially build two arrays of batteries on the site to store electricity from other plants, primarily nuclear and solar energy. The first set of 50-MW batteries will open by the end of 2025. The second set of 167 MW is expected to be ready in October 2027.

Duke has been shutting Allen’s five coal-burning units gradually since 2021. The final unit will close at the end of 2024.

More: *WFAE*

NORTH DAKOTA

PSC Approves $440M Tx Line

The Public Service Commission last week voted 2-1 to approve a $440 million, 85-mile transmission line that will be paid for in part by Otter Tail Power and Montana-Dakota Utilities customers.

With the approval of the 345-kV line, MDU customers will pay an additional 12.3 cents/month and Otter Tail customers about 17.7 cents/month.

More: *North Dakota Monitor*

OREGON

EQC Approves Redo of Climate Program After Lawsuit Derailed It

The Environmental Quality Commission last week voted unanimously to approve a program that sets emission targets and will serve as a foundation for the state's drive to reduce greenhouse emissions.

The vote came 11 months after a court invalidated the original 2021 program. NW Natural, Avista and Cascade Natural Gas sued to block the plan in 2023, saying in the process of imposing state regulations to cap and reduce emissions, the commission failed to submit required disclosures to the companies.

Little changed from the original standards, with the mandated targets for reducing greenhouse gas pollution remaining at a 50% reduction by 2035 and a 90% reduction by 2050.

More: *Oregon Capital Chronicle*

SOUTH CAROLINA

Final Executive Punished for VC Summer Failure

U.S. District Judge Mary Geiger Lewis last week sentenced Jeff Benjamin, a top executive for Westinghouse Electric, to 10 months in prison and a fine of $100,000 for his role in the failure of the V.C. Summer Nuclear Plant.

Benjamin pleaded guilty in December to aiding and abetting the failure to keep accurate corporate records. Benjamin admitted to telling presidents of the now-defunct SCANA that the plan to build two nuclear reactors was still on track, despite the subcontractor his company had hired saying there was no way they would be done in time.

Westinghouse eventually told SCANA and state-owned Santee Cooper, the utilities that jointly hired the company to build the two reactors, in 2017 that the company was facing a $6.1 billion loss from the project. The utilities then abandoned the project, but not before spending $9 billion.

More: *South Carolina Daily Gazette*

SOUTH DAKOTA

Summit Carbon Solutions Reapplies for Permit

Summit Carbon Solutions last week resubmitted a permit application for its proposed carbon dioxide pipeline to the Public Utilities Commission.

The move comes more than a year after the PUC rejected the company's initial application and said the route was non-compliant with county laws mandating minimum distances between pipelines and existing features. Summit's latest route includes 700 miles with connections to 14 ethanol plants, plus a proposed sustainable aviation fuel plant. Overall, the $9 billion pipeline would span 2,500 miles with connections to 57 ethanol plants in five states.

Summit already has permits in Iowa and North Dakota. A decision is pending in Minnesota, while Nebraska has no state permitting processing for carbon pipelines.

More: *South Dakota Searchlight*

VIRGINIA

Dominion Halts Pumped Storage Station Development

Dominion Energy last week announced it will not proceed with the proposed $2 billion Tazewell Pumped Storage Facility in Tazewell County.

Dominion said it stopped development due to "the cost impact to our customers, the expiration of a FERC permit and the availability of more affordable and higher-capacity generation options."

More: *Bluefield Daily Telegraph*

Dominion Requests Rate Hikes to Cover OSW, SMR Costs

Dominion Energy recently filed requests with the State Corporation Commission to raise rates to cover the expenses associated with its offshore wind farm and early development of small modular nuclear reactors.

The request would charge average residential customers an additional $2.89 a month.

The SCC must review and approve the proposals, which are planned to take effect on Sept. 1, 2025.

More: *VPM*

Judge Deems Gov. Youngkin's Actions to Withdraw State from RGGI 'Unlawful'

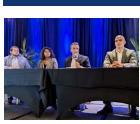
Floyd County Circuit Court Judge Randall Lowe last week ruled Gov. Glenn Youngkin acted unlawfully by withdrawing the state from the Regional Greenhouse Gas Initiative.

In his opinion, Lowe wrote that "the only body with the authority to repeal the RGGI regulation would be the General Assembly. This is because a statute, the RGGI Act, requires the RGGI regulation to exist. For the reasons set out in this opinion, the court finds that the attempted repeal of the RGGI regulation is unlawful, and thereby null and void."

The Youngkin administration has said it will appeal the decision.

More: *Virginia Mercury*

Mid-Atlantic news from our other channels



Maryland Energy Storage Initiative to Put 750 MW Online by 2028

Chesapeake Solar Industry Prepares for Trump 2.0 'Solarcoaster'

NJ Scrutinizes Solar Net Metering Strategy

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