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2025 NARUC Annual Meeting and Education Conference

Regulators Urge FERC to Honor State Authority over Large Load Interconnections

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The NARUC resolution signals that state regulators nationwide are opposed to the Department of Energy's effort to enable FERC to supplant states' authority over large load interconnections.

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MISO

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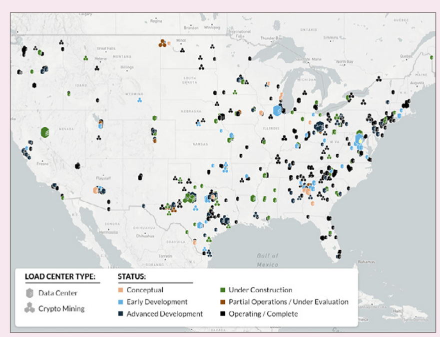

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Recent FERC orders and related legal decisions have succeeded in greatly blurring the formerly bright line between state and federal authority, with state regulatory oversight increasingly diminished as a consequence.

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DOE Request to FERC on Large Load Interconnections May Further Limit State Powers

Federal Government Wants to Oversee Data Center Interconnections

By Peter Kelly-Detwiler

Why This Matters

Recent FERC orders and related legal decisions have succeeded in greatly blurring the formerly bright line between state and federal authority, with state regulatory oversight increasingly diminished as a consequence.

Peter Kelly-Detwiler

On Oct. 23, U.S. Secretary of Energy Chris Wright *ordered* FERC to initiate a new rulemaking proceeding in order to "ensure efficient, timely and non-discriminatory load interconnections" for large loads exceeding 20 MW.

In his letter to FERC, Wright observed that, "Historically, the commission has not exerted jurisdiction over load interconnections." However, Wright added, "It is my view that the interconnection of large loads directly to the interstate transmission system to access the transmission system and the electricity transmitted over it falls squarely within the commission's jurisdiction."

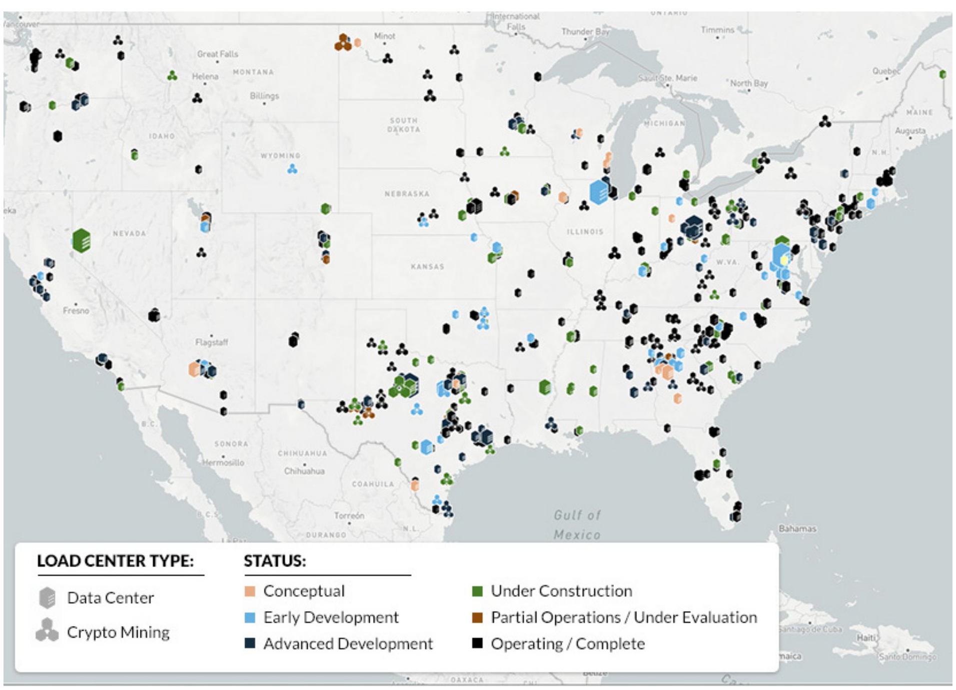
Wright then ordered FERC to consider a proposed rule, with action to occur no later than April 30, 2026, and attached an Advance Notice of Proposed Rulemaking (ANOPR) entitled, "Ensuring the Timely and Orderly Interconnection of Large Loads."

The ANOPR suggested numerous changes to the status quo that would accelerate future interconnections, cut study times and reduce associated interconnection costs. Among other aspects, the proposed DOE approach would enable customers to file joint, co-located load and generation interconnection requests directly to FERC.

An Argument for Arrogating This Power to the Feds

This initiative constitutes an entirely new approach to load interconnections, which historically have been regulated by individual states. In asserting an expanded legal ambit for FERC in this arena, the ANOPR makes several arguments:

- Large load interconnections constitute a "critical component of open access transmission service." They are similar in nature to generator interconnections and thus need "minimum terms and conditions to ensure non-discriminatory transmission service."
- FERC already oversees wholesale electricity rates and owns the mandate to ensure that wholesale rates are just and reasonable. This mandate should be extended to large loads and data centers.
- FERC also exercises jurisdiction over transmission in interstate commerce. Since large loads generally interconnect directly to high-voltage transmission, they should be regulated by FERC.
- States' regulatory authority is not affected or limited, since the ANOPR does not affect retail sales or the siting of power plants.



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Proposed issues addressed include the speed of interconnection studies, treatment of hybrids (large loads with on-site generation) and net power flows at or near the same point of interconnection, and the flexibility of operations and capability of being curtailable.

The ANOPR also suggests that load and hybrid facilities should be treated similarly to assets in supply interconnection queues — paying standardized deposits for studies, risking penalties for withdrawals from the queue, and being subject to readiness requirements.

The States Push Back

Not surprisingly, state regulators quickly made their concerns known. In its Nov. 11 meeting, the National Association of Regulatory Utility Commissioners (NARUC) adopted *a resolution* urging FERC "to preserve and affirm states' retail regulatory authority under the Federal Power Act, ensure that large load interconnections do not compromise grid reliability or impose undue costs on retail customers, and respect state tools for promoting system flexibility and equitable cost allocation." (See related stories, *Regulators Urge FERC to Honor State Authority over Large Load Interconnections* and *State Regulators Ponder Federal Role in Large Load Interconnections*.)

Among topics NARUC raised were a fear that FERC might assert its authority over retail end-use sales, a concern that large infrastructure investments to serve loads might unduly burden other ratepayers, and the recognition that "at least 20 states have approved or have pending large load tariffs or similar measures, which may include financial commitments, curtailment protocols and minimum contract terms to allow for the rapid interconnection of large loads without compromising grid reliability or unduly burdening existing retail customers."

In other words, they already were addressing the problem.

'Bright Line' Separating Powers Has Been Fading in Recent Years

State regulators raise some valid points, especially concerning the affirmation of regulatory responsibilities that were clarified by the 1935 passage of the *Federal Power Act*. That law gave federal regulators authority over interstate electricity commerce, created the Federal Power Commission (the precursor to today's FERC) and established a *"bright line"* separating regulatory powers of state and federal authorities.

However, if recent history is any guide, NARUC may not have much success in opposing or even influencing this new DOE effort, as recent FERC orders and related legal decisions have succeeded in greatly blurring the formerly bright line, with state regulatory oversight increasingly diminished as a consequence.

That dynamic began with the restructuring of power markets in numerous states during the 1990s, with FERC *Order 888* (1996) that established open access to transmission while introducing the concept of ISOs, and *Order 2000* (1999) that created larger regional transmission operators.

FERC Order 719 (2008), in addressing demand response, further helped fray the strength of state regulators, requiring grid operators to accept demand response bids into wholesale markets, though 719 did not establish a framework for compensation. This order signaled an explicit federal regulatory reach across the bulk power into the state-regulated distribution system for the first time.

That incursion was further strengthened by *FERC Order 745* (2011), which directed that "demand response resource must be compensated for the service it provides to the energy market at the market price for energy." This was the first time that assets in the distribution system were incorporated into federal oversight, but states had the critical right to opt out, thus maintaining an important regulatory prerogative.

FERC Order 841 (2018), focusing on energy storage, went a step beyond that initial movement into the states' realm. It specifically addressed storage resources behind the meter in the utility distribution system. Most critically, it did not allow individual states to opt out. Unsurprisingly, Order 841 did not sit well with state regulators, who saw this as an overreach into their jurisdiction.

NARUC *filed suit* in an attempt to overturn Order 841 but eventually lost in the D.C. Circuit of the U.S. Court of Appeals. That appellate court ruling indicated that since the activity of these storage assets affected wholesale markets, FERC authority should prevail.

FERC Order 2222 (2020) went a step further down this path, allowing all types of customer-sited assets to be aggregated and to participate in wholesale markets. In this instance, NARUC, the Edison Electric Institute and other parties *sought a rehearing* but were denied.

What's Next

Comments on the ANOPR are due Nov. 21, and there certainly will be many provided, as the size of the prize at stake is enormous: interconnection requests in the many hundreds of gigawatts (even excluding Texas with its more than 200 GW of interconnection not subject to FERC oversight), capital expenditures worth hundreds of billions of dollars and outsized potential effects on ratepayers.

With two newly minted appointees and a new chair, FERC will have its work cut out for it. The current fragmented approach of interconnection management has quickly become an unruly Tower of Babel. Demand forecasting is imprecise and inconsistent, and one can point to inflationary pressures (estimated in the billions of dollars in PJM alone) that already have resulted from this lack of precision.

Today, each utility and grid operator is developing its own processes and procedures, in the face of loads that are simply unprecedented in scale, and few — if any — approaches are consistent with one another.

State regulators' toes may be stepped on once again, and the regulatory bright line further blurred. But given the size of what is at stake, that pain may prove to be necessary, bringing some standardization, clarity and consistency to the very complex and interwoven system-of-systems that is our U.S. power grid.

— Around the Corner columnist Peter Kelly-Detwiler of NorthBridge Energy Partners is an industry expert in the complex interaction between power markets and evolving technologies on both sides of the meter.

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GridEx Participants Report No Disruption from Shutdown ERO Insider

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

How ERCOT's RTC+B is a Game Changer for Market Operations

By Portia Gilman

Portia Gilman

ERCOT is preparing to launch its Real-Time Co-Optimization + Batteries (RTC+B) initiative, perhaps the most sweeping market redesign in its history.

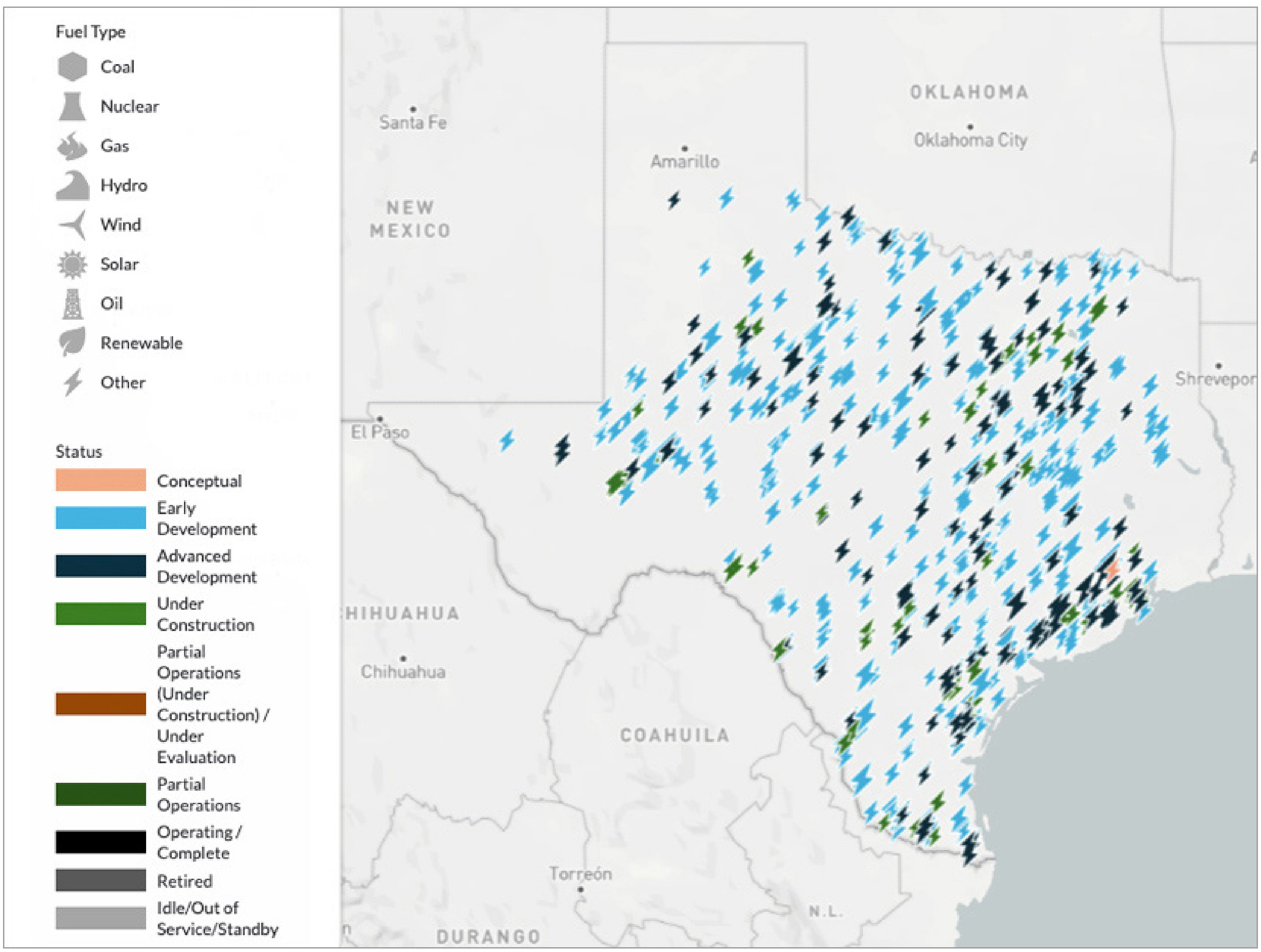
This transformation, scheduled to launch Dec. 5, will touch virtually every aspect of the market, from energy to ancillary services, introducing a more dynamic, efficient and integrated approach to market operations.

For battery operators in particular, RTC+B is a game changer. The redesign recognizes batteries not as separate charging and discharging assets but as unified energy storage resources (ESRs), allowing operators to more easily participate simultaneously in energy and ancillary services markets. This shift will enable batteries to capture more value, optimize dispatch and contribute to overall market efficiency in ways that were impossible under ERCOT's legacy design.

ERCOT's RTC initiative has been years in the making. It initially was focused solely on creating a real-time, co-optimized market that simultaneously would clear energy and ancillary services, accounting for each resource's capabilities and system conditions to determine the most efficient dispatch. Following ISO-NE's introduction of a *co-optimized market* in March, ERCOT will be the last ISO to make this shift.

ERCOT *paused* its RTC initiative in the wake of Winter Storm Uri. The project was restarted in 2023, adding the battery (+B) component to reflect the rapid growth of battery energy storage capacity in ERCOT.

Texas is one of the *fastest-growing* battery storage markets in the country, second only to *California* in terms of installed capacity. In fact, ERCOT nearly doubled its battery capacity between 2023 and 2025



Battery projects in development or under construction in ERCOT as of April 29, 2025. | *Yes Energy's Infrastructure Insights Module* and is now approaching *10 GW*.

Even more capacity is in the pipeline. Yes Energy is tracking more than 1,100 battery projects, totaling 180.5 GW, under construction or in development across the region.

Market Design Overhaul

RTC+B fundamentally reshapes how ERCOT manages energy and ancillary services, creating a market that's more dynamic, efficient and aligned with modern resources like batteries.

At the heart of the redesign is the replacement of legacy constructs such as the operating reserve demand curve (ORDC) with ancillary services demand curves (ASDCs). These curves provide product-specific pricing for reserves — including regulation up ECRS and spinning reserves — enabling batteries and other flexible resources to see relative value signals and prioritize offers accordingly.

Under RTC+B, energy and ancillary services are *co-optimized in real time*, meaning ERCOT simultaneously clears energy and reserves through the SCED rather than relying on a separate ORDC process to clear reserves. Co-optimization already exists in the day-ahead in ERCOT and will continue after RTC+B.

This real-time co-optimization ensures that resources are dispatched efficiently across both markets, with the goals of improving overall market efficiency, reducing real-time energy costs and narrowing day-ahead to real-time price spreads over time.

ERCOT also will introduce virtual offers for ancillary services in the day-ahead market, which will increase liquidity by allowing more resources, including batteries, to participate flexibly.

To prepare for these changes, ERCOT conducted market trials in three stages:

The RTM – After (Post-RTC) | *Yes Energy*

open-loop testing, closed-loop testing and final go-live validation. These trials allow participants and market operators to observe clearing prices, test new reports and ensure that the transition to RTC+B will be as seamless as possible.

Batteries Take Center Stage

Under ERCOT's legacy framework, batteries were split between charging and discharging functions, treated as two separate resources with separate datasets in ERCOT's systems. This "combo model" created extra complexity for resource owners, requiring manual processes to achieve consistency across operating plans, telemetry and bid curves. RTC+B eliminates this dual structure, replacing it with a single ESR designation that unifies a battery's operations into one resource type.

Batteries will submit a combined energy bid-offer curve (EBOC), which integrates both charging and discharging into a single market signal. Negative EBOC values represent charging, allowing batteries to signal both their willingness to consume and supply energy. A low sustained limit (LSL) will replace the maximum power consumption (MPC) parameter, enabling operators to define realistic operational constraints within the unified framework.

This structure allows batteries to participate dynamically across both energy and ancillary services markets, supporting real-time co-optimization. Battery operators also can adjust day-ahead awards in real-time based on updated system conditions, pivot quickly between market products and respond to five-minute reserve updates.

RTC+B will transform how participants interact with ERCOT through data and operational reporting. Under the new framework, resources, including batteries, will integrate EBOCs, LSLs and regulation signals into ERCOT's new market-clearing and settlement processes.

These capabilities not only give operators unprecedented flexibility and revenue potential, but also should improve market liquidity, enhance competition and help moderate price spikes for both energy and ancillary services.

In other words, with RTC+B, batteries no longer are just flexible resources. They become central drivers of ERCOT's next-generation market efficiency.

Looking Ahead

With RTC+B, batteries move from being supporting players to central drivers of ERCOT's next-generation market. By unifying charging and discharging into a single energy storage resource, introducing realistic operational bids and offers through the new EBOC, and integrating along with real-time co-optimization across energy and ancillary services markets, the redesign unlocks new operational flexibility and revenue potential.

As the Dec. 5 go-live approaches, battery operators who understand and use these changes will be well positioned to capture value, enhance market efficiency and shape the future of the Texas electricity system.

(For more information, see this *on-demand webinar*.) ■

Portia Gilman manages the Yes Energy market monitoring team. RTO Insider is a wholly owned subsidiary of Yes Energy.

The RTM – Before (Pre-RTC) | *Yes Energy*

Regulators Urge FERC to Honor State Authority over Large Load Interconnections

NARUC Resolution Takes Aim at DOE ANOPR

By Robert Mullin

SEATTLE — The National Association of Regulatory Utility Commissioners passed a resolution urging FERC to resist the Department of Energy's push to give itself jurisdiction over large loads interconnecting with the grid — an authority historically belonging to state regulators.

NARUC's Board of Directors approved the measure (*EL-1*) in a Nov. 11 vote at the organization's Annual Meeting.

The vote comes just over two weeks after Energy Secretary Chris Wright issued an Advance Notice of Proposed Rulemaking (ANOPR) pressing for FERC to extend its jurisdictional authority to include the interconnection of large loads — including hyperscale data centers. (See *Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections*.)

DOE argued the new rules would be in the public interest and align with the Trump administration's goals of reviving U.S. manufacturing and dominating the development of artificial intelligence.

But through the NARUC resolution, state regulators are asking FERC to "preserve and affirm states' retail regulatory authority under the Federal Power Act" and "ensure that large loads do not compromise grid reliability or impose undue costs on retail customers."

The resolution provides NARUC a foundation for developing initial comments on the ANOPR, Idaho Public Utilities Commissioner John R. Hammond Jr., chair of the group's Committee on Electricity, told *RTO Insider* at the conference.

"We know the resolution is broad. We wanted it to be nimble," said Virginia State Corporation Commission Judge Kelsey Bagot, who guided the document through the committee to gain consensus ahead of the board vote.

"We did get a lot of collaboration among NARUC members" on the resolution, Bagot said.

Hammond agreed that the group found a lot of "commonality" on the issue.

Comments on the ANOPR are due Nov. 21, which Bagot acknowledged is a "tight deadline."

Idaho Public Utilities Commissioner John R. Hammond Jr. speaks Nov. 10 during NARUC's Annual Meeting in Seattle. | © *RTO Insider*

Why This Matters

The NARUC resolution signals that state regulators nationwide are opposed to the Department of Energy's effort to enable FERC to supplant states' authority over large load interconnections.

'Unprecedented Expansion'

In an Oct. 23 *letter* to FERC accompanying the ANOPR, Wright contended that "the interconnection of large loads directly to the interstate transmission system to access the transmission system and the electricity transmitted over it falls squarely within the commission's jurisdiction."

The ANOPR offered a handful of legal justifications for the change, saying that:

- large load interconnections are a critical component of open access transmission service that require minimum terms and conditions to ensure non-discriminatory transmission service;
- interconnection of large loads directly affects FERC-jurisdictional wholesale rates, over which the FPA has granted the commission exclusive authority; and
- the rule change would not violate state jurisdiction over retail sales.

The ANOPR also said that any views controverting the changes would conflict with the FPA's core requirement that FERC have exclusive jurisdiction over transmission in interstate commerce.

But with the NARUC resolution, state regulators are clearly disputing those points.

A *draft* of the resolution said the proposed rulemaking "represents an unprecedented expansion of federal jurisdiction and potential intrusion on the states' historic retail regulatory authority under the Federal Power Act, introducing potential confusion, unintended customer consequences and/or legal uncertainty where none currently exists."

But the final resolution removed that language — and toned down other statements, instead saying "it is imperative that FERC, in any final rulemaking, make clear that it is affirmatively not asserting jurisdiction over end-use sales, which falls squarely within the exclusive jurisdiction of state retail energy regulatory authorities."

The resolution goes on to explain that state regulators exercise oversight over resource adequacy, grid reliability and maintaining affordability for retail customers. It says their authority over integrated resource planning stems from their "reserved jurisdiction" under Section 201(b) of the FPA, "enabling states to oversee utilities' long-term forecasting of electricity demand and evaluation of supply- and demand-side resources to meet that demand in a cost-effective, reliable and sustainable manner."

The resolution notes also that NERC's most recent Long-Term Reliability Assessment shows electricity demand is growing at the fastest rate in two decades, with especially steep increases expected for winter peaks. It cautions that "large load interconnections without sufficient available generation capacity could threaten reliable power service to existing retail customers," with grid operators potentially lacking sufficient resources to maintain system stability during peak demand and extreme weather events.

The regulators warn also that the costs for large load interconnections, presumably mandated by FERC — including needed transmission upgrades — could unfairly fall to retail ratepayers "if not properly allocated."

The resolution points out that at least "at least 20 states have approved or have pending large load tariffs or similar measures, which may include financial commitments, curtailment protocols and minimum contract terms to allow for the rapid interconnection of large loads without compromising grid reliability or unduly burdening existing retail customers."

Drawing a Line

Judge Bagot expressed confidence that FERC can "find a solution states can be comfortable with," noting the commission's recent decision on Tri-State Generation and Transmission Association's High Impact Load Tariff (HILT) could offer perspective on where the commission will stand.

In that order, FERC rejected the HILT, saying "certain aspects" of the proposed tariff "appear to present an impermissible intrusion on retail rate regulation" by state commissions. (See *FERC Rejects Tri-State's 'High Impact Load Tariff' Aimed at Data Centers*.)

State regulators think "a line can be drawn" that preserves state authority but "allows the feds to be involved" with large load interconnections, Bagot said. ■

An earlier version of this article contained language from a draft version of the resolution. The story has been updated to reflect the wording in the final document.

NARUC Report Seeks to Make Headway on Gas-electric Challenges

Effort Looks to Provide Regulators Tools to Address Evolving — and Stubborn — Issue

By Robert Mullin

SEATTLE — A new report from the National Association of Regulatory Utility Commissioners offers state regulators an extensive set of recommendations intended to address risks stemming from the ever evolving interdependence of the natural gas and electric sectors in the U.S.

The release of the 40-page *paper* by NARUC's Gas-Electric Alignment for Reliability (GEAR) Task Force was a showpiece at the organization's annual meeting. The report highlights an issue that has dogged the two industries for over a decade: how to get them to better coordinate their actions to maintain grid reliability.

But progress has been halting, as NARUC Executive Director Tony Clark indicated at the start of a Nov. 11 panel discussion at the meeting.

"Ronald Reagan said the closest thing to eternal life on this earth was a government program, but I'm not so sure. For regulatory offices, the closest thing to eternal life is the gas-electric conversation," Clark said.

The report's authors, which included state regulators and executives from gas and electric companies, wrote that "the goal of GEAR was to provide a venue for key regulatory and industry stakeholders to discuss and develop solutions to the reliability problems caused by the misalignment of the gas and electric industries."

Notable Quote

"Ronald Reagan said the closest thing to eternal life on this earth was a government program, but I'm not so sure. For regulatory offices, the closest thing to eternal life is the gas-electric conversation."

— NARUC Executive Director Tony Clark

NARUC Executive Director Tony Clark (left) leads a panel discussion on the GEAR Task Force on Nov. 11 at NARUC's annual meeting in Seattle. | *© RTO Insider*

They compared "achieving the highest level of reliability" to obtaining an insurance policy.

"It must be planned and purchased ahead of time; you hope you never need it; and if it is not used, it will invariably look expensive," they wrote. "It is important for regulators and industry experts to help the public understand that those characteristics do not mean the cost to assure reliability are not prudent investments."

The report draws on source materials and presentations by a wide swath of energy organizations, such as the North American Energy Standards Board, NERC and its regional entities, FERC, RTOs/ISOs, the Electric Power Supply Association and the Interstate Natural Gas Association of America, as well as BP.

The report outlines nine recommendations for state officials:

- the creation of a voluntary, ongoing Natural Gas Readiness Forum intended to improve natural gas "value chain reliability via the promotion of communication, peer-to-peer connections, situational awareness and education among its participants." The task force advised that the American Gas Association lead this effort.
- support for federal permitting changes to encourage the construction of new natural gas pipeline infrastructure.
- have states and organized power markets examine ways to increase investment in and development of "storage of all types" to support the grid in times of high demand.
- encourage regulators to contact their RTOs/ISOs and utilities and review NERC information regarding load shedding practices, and evaluate whether changes are needed given the current electricity consumption landscape.
- ensure greater liquidity and transparen-

cy in natural gas markets around winter weekends, when trading is limited.

- "in lieu of direct winterization regulations for natural gas production," examine the "need and feasibility of a market-driven process" that allows utilities and generators to recover costs for premiums they pay for improved winter performance.
- encourage state regulators and policymakers to support "market-based solutions" to incentivize gas procurement and "provide economic certainty, consistent with recommendations to improve natural gas unit scheduling and dispatch."
- consider development of "robust" demand response programs to shift energy use during periods of high demand or system stress.
- support or adopt measures "that facilitate more timely and frequent use of interstate capacity release or asset management arrangements" by utilities.

The GEAR Task Force expects the alignment of the gas and electric systems to remain an ongoing challenge for NARUC, its members and industry in the years and decades to come," the report says. "These recommendations should serve as a backdrop and ongoing point of discussion to assist regulatory agencies and their partners in serving the needs of the natural gas system, the electric grid and utility customers."

'An Education'

During the Nov. 11 panel, Clark asked GEAR participants what state regulators should take away from the report.

Georgia Public Service Commissioner, GEAR Chair and outgoing NARUC President Tricia Pridemore said her state already allows electric utilities to roll firm gas transportation and storage costs into their rate base.

"It's just a part of our customer expectations and how we operate," Pridemore said. "Developing a path within your state to do the same provides liability assurances and insurance that's not matched, and that is a path that I think regulators, who fully understand the systems more than our friends in the legislature do, should be communicating now."

Kansas Corporation Commissioner Dwight Keen said he thinks state governments should take a role in ensuring that the gas and electric industries "provide continuity of attention to the nuances, the methods and the means by which we continually re-evaluate and reassess … the kinds of techniques we can use to really enhance reliability going forward."

Rhode Island Public Utilities Commissioner Ron Gerwatowski expressed regret that the report contained many recommendations his agency doesn't have the authority to implement, but he appreciated that it provides "an education."

"There's a lot of information that's confirming things, some of which we know already, but other things that are new," Gerwatowski said, adding that the report gives regulators additional information to bring into federal proceedings or conversations at RTOs, allowing them to "act as advocates to try to move things along" when gas and electric entities come into conflict.

Arizona Corporation Commissioner Lea Marquez Peterson said the effort offered "a clear realization how different every state is. In Arizona, we don't have natural gas supply; we're dependent on neighbors and distribution lines that come through our state." She said developing the report revealed the level of interdependence among states on gas issues.

Michigan Public Service Commissioner Dan Scripps recommended that fellow regulators take time to understand their utilities' load shed procedures because it's "way, way too late" once a state is in an emergency.

Scripps advised also that regulators in organized electricity markets work with RTOs "around scheduling and dispatch as well as the incentives for things like out-of-market support for natural gas purchases."

Iowa Utilities Commissioner Josh Byrnes said the report is "a script" for having conversations with utilities.

"Sometimes I struggle with what can we do as regulators when it comes to some of these topics — like, some of them feel like they're beyond our scope, [or] sometimes it feels like it's more federal level, or it's just like, where do I fit into the conversation?" Byrnes said. "So I feel like this report is going to help me to start those conversations and try to find that purpose moving forward as a regulator in this issue." ■

State Regulators Ponder Federal Role in Large Load Interconnections

NARUC Panelists Laud State Approaches, See FERC Limitations

By Robert Mullin

SEATTLE — The Trump administration's push to give FERC jurisdiction over large load interconnections could leave the agency biting off more than it can chew around complex state-run processes, while failing to accomplish the intended goal of speeding approvals of hyperscale data centers.

That was a top takeaway from a Nov. 12 panel discussion on the role of U.S. states in the permitting of "critical" energy infrastructure, held at the National Association of Regulatory Utility Commissioners (NARUC) annual meeting in Seattle.

The discussion among state regulators replaced a previously scheduled *meeting* of the Federal and State Current Issues Collaborative on the same topic, which was canceled because FERC representatives were restricted from travel because of the federal government shutdown.

The context of the discussion was shaped by Energy Secretary Chris Wright's Oct. 24 Advance Notice of Proposed Rulemaking (ANOPR), which seeks for FERC to extend its authority to include the interconnection of large loads. The NARUC conference featured passage of a resolution pushing back against that effort. (See related stories, *Regulators Urge FERC to Honor State Authority over Large Load Interconnections* and *DOE Request to FERC on Large Load Interconnections May Further Limit State Powers*.)

Virginia State Corporation Commission Judge Kelsey Bagot kicked off the panel saying state and federal regulators mostly seek the same outcome in the large load interconnection issue, "which is this idea of speed to power."

But Bagot posed the key question confronting regulators facing the potential for massive load growth in their states: how to ensure permitting is "as efficient as possible" without "losing out on the really important pieces that underlie why we have this permitting process in the first place" — namely protections around customer affordability, livability and the environment.

Panel participants raised crucial points, including:

- State permitting of transmission and energy resources needed to interconnect large loads entails a highly complex process that includes not just utility commissions but environmental agencies, siting boards, localities, community groups, Tribes, landowners and various kinds of utilities.
- Those permitting processes are efficient, often being completed within a year.
- FERC may not be equipped to take on the added responsibility of such complex processes, often rooted in local concerns, and its control could invite more protests and delays of projects.

From left: Gabriella Passidomo Smith, Florida PSC; Stacey Paradis, Illinois Commerce Commission; Kelsey Bagot, Virginia SCC; Brian Rybarik, Washington UTC; Kathryn Zerfuss, Pennsylvania PUC; Karen Kemerait, North Carolina Utilities Commission; Pradip Chattopadhyay, New Hampshire PUC | © *RTO Insider*

Notable Quote

"I don't want to lose the progress that's there in search of the sort of one-size-fits-all solution that may or may not result in faster permitting processes, or permitting processes that may be faster on the front end but end up tied up in litigation for for many, many years."

— Virginia SCC Judge Kelsey Bagot

'Extremely Complicated'

Florida Public Service Commissioner Gabriella Passidomo Smith emphasized how her state already prioritizes speed in permitting. She noted Florida has three different statutes covering the siting of natural gas infrastructure, power plants and transmission lines.

"These siting acts really address the environmental impacts of power plant, transmission line and natural gas pipeline construction and operation, with the primary goal of streamlining the permitting process while ensuring the protection of Florida's natural resources," Passidomo Smith said.

While the Florida Department of Environmental Protection is the lead agency for siting permits, the process includes the Department of Economic Opportunity, the Florida Fish and Wildlife Conservation Commission and a siting board comprised of the governor and the cabinet.

Throughout the process, Passidomo Smith said, affected local governments can provide land-use consistency determinations, with regional planning councils and water management districts participating in the review.

The role of the PSC, she said, is to be the first stop to determine need for new capacity after a generation or load-consuming project has been proposed. The proposal starts a 45-day clock for the commission to hold a hearing, followed by a requirement to issue a determination within 60 days of the hearing.

Certain transmission projects can be "extremely complicated, if you're talking about going through conservation land, tribal lands," she said. "You might just have one property owner and a NIMBY issue that could be involved. You know, it could be simple; I think it increasingly is less so."

Illinois Commerce Commissioner Stacey Paradis said she was speaking for fellow commissioners in the Mid-America Regulatory Conference region in saying they want to ensure efficient permitting. But they're also "very interested in maintaining state control" over large load interconnections and are concerned that local community engagement could be lost through federal control over the process.

Paradis said Illinois law sets specific requirements for public participation, stakeholder engagement, environmental assessments, and public and evidentiary hearings before the commission can act on an application.

She noted the ICC in the past decade has taken on responsibilities related to integrated resource planning, resource adequacy, the siting of solar, the development of new nuclear resources and the examination of pipeline siting. That's all part of a state strategy to consolidate energy-related processes within one agency, although the ICC also works with sister agencies such as the Illinois Power Agency, Illinois EPA and the state Department of Natural Resources.

Despite that workload, Paradis said that in the past 15 years, the ICC has completed permitting on every electricity-related project within 365 days.

"So, all of that moves still relatively quickly, even though we have those five stages," she said.

Single-size Permitting

Bagot, who previously worked as an attorney at FERC, pondered how Virginia's process of permitting a high volume of large load projects would compare under federal authority.

Bagot said under existing practice the SCC has authority to issue certificates for public convenience and necessity (CPCNs) for nearly all projects rated at 115 kV or above. While the state's Department of Environmental Quality is separately responsible for environmental reviews, its findings are incorporated into SCC's CPCN proceeding. She said Virginia's process gives localities a "strong role" in the permitting process.

Bagot said that while Virginia has no statutory deadline for the SCC to issue a CPCN, the agency's typical timeline has been eight to nine months, which doesn't include "the random exception here or there for particularly challenging projects" or instances when a utility itself seeks alternative routes after local feedback.

"So, to the extent the process is delayed, it's often on the part of the utility after community engagement, and they've come to some resolution, and want to make sure that that resolution is reflected in the filing, which we obviously want to encourage, because those types of solutions, I think are a win-win for everybody," she said.

Bagot pointed out that, over the past three years, the SCC has received about eight to 20 transmission CPCN applications annually, compared with FERC dealing with 15-20 natural gas CPCN applications a year in the same period.

"They're doing about the same amount of certificates each year as the Virginia commission is doing for transmission, and that's just one of many states," she said. She added that she wants to understand what amount of resources and staff FERC or another federal agency would require "to really engage meaningfully in these permitting processes for transmission to the extent it is smooth."

The rapid spread of data centers has made transmission siting in Virginia's "Data Center Alley" in Loudoun County particularly contentious. The process requires much more engagement with increasingly sophisticated community groups to negotiate solutions, which reduces the kind of appeals and litigation risk that slows projects, Bagot said. She added that states "are working very hard" at the legislative and commission levels to make processes "as efficient as possible."

"I don't want to lose the progress that's there in search of the sort of one-size-fits-all solution that may or may not result in faster permitting processes, or permitting processes that may be faster on the front end but end up tied up in litigation for many, many years," Bagot said.

'Strong Track Record'

Pointing out that Virginia is "an outlier" in the number of transmission requests the state is fielding, Washington Utilities and Transportation Commission Chair Brian Rybarik still echoed Bagot's concern that FERC would be shouldering "a lot" in assuming authority over large load interconnections in every state.

But more important was Bagot's "one-size-fits-all" concern about a federal process, Rybarik said.

"How do you get that connection to the landowners that are actually being impacted?" he said. "The energy transition, load growth, everything we're seeing, is a really important thing for the country, but it affects a certain number of people a lot more than others, and so we really need to make sure that we make that connection to everybody."

On the topic of state permitting of transmission, Rybarik said that while critics among industry stakeholders "tend to focus on the negative," Washington's Department of Ecology approves 83% of applications that come before the agency.

"I think that's a pretty strong track record to look at. We can focus on the outliers for the negative, but it really is working well, and states are working well to move these things forward," he said. "Agencies like the UTC are bringing leaders together and asking our stakeholders, 'How can we advance our processes?'" ■

Former FERC Commissioners Ask Supreme Court to Preserve Agency Independence

By James Downing

Eleven former FERC commissioners filed a brief with the Supreme Court arguing it should uphold *Humphrey's Executor* or carve out an exception for ratemaking agencies.

The court is poised to hear oral arguments in *Trump v. Slaughter* on Dec. 8, in which former Federal Trade Commissioner Rebecca Kelly Slaughter is arguing President Donald Trump overstepped his authority in firing her in March.

The case comes 90 years after the Supreme Court found that Congress could limit the president's authority to fire members of regulatory agencies in another case involving an FTC commissioner, which has helped guarantee agency independence since then. In an order overturning an injunction in a related case earlier this year, a majority on the court seemed poised to overturn the precedent but noted it would benefit from briefing on the issues. (See *Will the Supreme Court End FERC's Independence?*)

"Overturning *Humphrey's Executor* would bulldoze the structural supports that Congress built into ratemaking commissions to protect its price-setting power from abuse," according to the brief, which was prepared by the Harvard Electricity Law Initiative's Ari Peskoe.

The *amici curiae* in the brief are a bipartisan group of former FERC commissioners who were nominated by presidents from George H.W. Bush through Trump's first term: Elizabeth Anne Moler, Donald Santa, Linda Breathitt, Pat Wood III, Nora Mead Brownell, Joseph T. Kelliher, Jon Wellinghoff, John Norris, Cheryl LaFleur, Neil Chatterjee and Richard Glick.

Congress has given ratemaking authority to multimember bipartisan commissions dating back to 1887 and limited the president's power to fire members only for "inefficiency, neglect of duty or malfeasance in office."

"By shielding agency action from political control, for-cause removal protections allow ratemaking commissions to sustain stable policies for the long-term benefit of regulated companies and American consumers," the brief says.

If the court decides to overturn or clarify *Humphrey's Executor*, the brief urged it to consider the "special historical status" it has indicated the Federal Reserve has in the *Seila Law* decision in 2020, in which the court found the president had unchecked authority to fire the director of the Consumer Financial Protection Bureau.

The Supreme Court | © *RTO Insider*

Why This Matters

The Supreme Court is holding oral arguments in December on a case that could end regulatory agencies' independence and allow the president to fire their officials for any reason.

Ratemaking agencies wield "legislative power" to set prices for investor-owned companies, the brief argues, and among all multimember agencies, only the Federal Reserve Board plays such a direct role in the economy, doing so with similar "legislative discretion."

"Overturning *Humphrey's Executor* without acknowledging ratemaking commissions' special status would greenlight one-party ratemaking bodies and allow presidents to eliminate staggered terms by firing holdover commissioners nominated by a previous president," the brief says. "Permitting the president to seize control over ratemaking could adversely affect how regulated companies perceive FERC and therefore increase the risk of financing pipelines and power lines. Ultimately, American consumers would pay higher energy prices."

Eliminating for-cause removal protections risks turning FERC into a partisan political body whose priorities flip every election cycle, and the resulting volatility would conflict with its historic focus on the long-term interests of consumers and the industries it regulates, the brief argues. Congress affords ratemaking commissions with wide discretion as they balance competing interests to find just and reasonable rates, and their bipartisan composition is an antidote against abuse of that discretion, it says.

"For-cause removal protections, staggered terms and partisan limits temper agency discretion by ensuring that decisions are informed by diverse and balanced perspectives," the brief says.

The Massachusetts legislature was the

first body to set up a ratemaking commission in 1869 to regulate what railroads charged in the state, and it was quickly followed by other states. The court upheld their creation in an 1877 decision.

A decade later, after the court found those state ratemaking commissions could not regulate interstate commerce, Congress set up the Interstate Commerce Commission to check the power that railroads exerted over the economy. The ICC had to have five commissioners with no more than three from one party; commissioners served staggered terms, could not hold other jobs, were forbidden from investing in regulated companies and had for-cause removal protections.

The ICC's structure remained durable and was adopted for other agencies over the years, including when Congress passed the Department of Energy Organization Act in 1977. Congress specifically rejected President Jimmy Carter's proposal to give DOE the old Federal Power Commission's ratemaking authority, with members arguing the power should go to a "collegial" body and not the department, where only the president's policies would guide its decisions.

"The age of the kings expired with the French Revolution," Rep. John Dingell (D-Mich.) said at the time, according to the *Congressional Record*. "I plead with this body, do not set up a new king here in Washington."

Dingell's "rhetorical flourish focused his colleagues on threats to liberty," which are a core concern in separation of powers cases, the brief says.

"By seizing ratemaking authority, 'one of the great functions conferred on Congress by the federal Constitution,' the president would secure vast direct control over the economy," the brief says. "Price-setting power would allow the president to increase profits of favored companies at the expense of consumers, who would face higher prices for goods and services. The president could also punish companies that oppose his policies or even raise energy prices in states that support his political rivals."

Congress wanted ratemaking power to be exercised in the "coldest neutrality" rather than unilaterally by the executive branch, the brief says.

"Elevating executive control over bipartisan deliberation, as petitioners urge, misunderstands Congress' ratemaking statutes and threatens to destabilize an economic model that has stood the test of time," the brief says.

The Supreme Court has repeatedly called the commission's ratemaking authority "legislative," so the commissioners urged the court, even if it overturns *Humphrey's Executor*, not to foreclose the possibility that ratemaking commissions remain immune from direct executive control. Separation of powers ought to allow Congress to create deliberative ratemaking bodies.

"FERC plays a direct role in our economy that, among the multimember agencies, is matched only by the Federal Reserve Board," the brief says. "Prices set by FERC are essential inputs across the economy that directly affect the cost of living and doing business. Maintaining for-cause removal protections for ratemaking commissions exercising legislative power would appropriately defer to Congress' powers over interstate commerce."

The brief also examines FERC's economic impact. It regulates 200,000 miles of interstate natural gas pipelines, 120,000 miles of high-voltage transmission and 85,000 miles of interstate crude pipelines, which transport more than $1 trillion worth of commodities per year.

That work remains important as artificial intelligence and reshored manufacturing grow the demand for electricity, and the oil and gas industry works to increase shipments of LNG abroad.

"FERC is more important than ever to American energy producers and consumers," the brief says. "Any change to FERC's structure should follow careful deliberations in Congress that weigh the potential benefits of reform against the possible harms caused by transforming FERC into a politically partisan body."

The commission's authority over energy markets gives it a direct and central role in the economy, like the Federal Reserve. The brief quotes former Federal Reserve Chair Alan Greenspan as saying, "Energy markets will remain central in determining the long-run health of our nation's economy."

"Like interest rates set by the Federal Reserve Board, energy prices impact costs across the economy and have material effects on total investment and consumption," the brief says. "Congress charged FERC and the Federal Reserve with promoting stable prices, which provide households and businesses with confidence to invest." ■

Tribes Urge FERC to Reject Wright's Hydropower NOPR

By James Downing

Why This Matters

Wright's NOPR seeks to accelerate development of new resources, but tribes argue it violates their sovereign powers to control their lands and waters.

Tribes asked FERC to reject a *proposal* from Energy Secretary Chris Wright to reverse a 2024 rule change that required consultation with them over hydropower projects proposed on their lands (*RM26-5*).

FERC rejected some pumped hydro facility applications that were for projects in Navajo Nation territory after tribal authorities opposed them and said it would start denying other projects on native lands whenever tribes opposed them. (See *FERC Rejects Pump Storage Projects Over Navajo Objections*.)

Wright told the commission that eliminating the rule was needed "for America to continue dominating global energy markets."

"The commission's longstanding policy has been to grant applications for preliminary permits over the opposition of third parties, such as federal land managers, similarly affected agencies or tribes, as applicable," Wright wrote in an Oct. 23 letter. "The reason is simple. The commission views preliminary permits as 'encouraging hydroelectric development by affording its holder priority of application (i.e., guaranteed first-to-file status) with respect to the filing of development applications for the affected site.'"

The preliminary permit only lets holders investigate the feasibility of a project; it does not give them any land-disturbing or other property rights, he added.

Recent orders denying preliminary permit applications because of objections from the Navajo created "an untenable regime whereby it has effectively delegated its exclusive statutory authority to issue preliminary permits to third parties," Wright said. The letter was accompanied by a Notice of Proposed Rulemaking the secretary filed under Section 403 of the Department of Energy Organization Act that, if approved, would return the rules to the status quo ante.

BPA's Bonneville Dam | *U.S. Army Corps of Engineers*

The National Hydropower Association told FERC in comments filed Nov. 12 that it supports the NOPR because it preserves the ability for developers to protect their early investment in a proposed project, while developers consult with regulators, tribes and other parties on their projects.

"Recognizing the importance of protecting a developer's critical investments early in the project development phase, years before any revenue stream from the project is secured, the commission should adopt the proposed NOPR and return to its longstanding policy that preliminary permits should be denied only if there is a permanent legal barrier to licensing the project," NHA said.

Objections raised early in the process lack information on the project's design, operating parameters and environmental effects, and FERC should not defer to the sentiments of other entities, whether that is a federal land manager, another agency or a tribe, the group argued.

The Navajo urged FERC to reject the NOPR and asked for another month to file more substantive comments.

"The 2024 policy resulted in developers engaging with the Navajo Nation, its political subdivisions and the local communities where the project would be located; obtaining non-invasive access authorization and permission to survey from the Nation under Navajo law; and reapplying for preliminary permits without opposition," it told FERC. "At least two proposed projects are in the feasibility stages of project development."

The Choctaw Nation of Oklahoma and Chickasaw Nation filed joint comments opposing the NOPR, saying it directly implicates their sovereign authority over tribal lands, waters and other cultural resources. They also complained about the comment deadline, which gave parties just 12 days to respond to the secretary's proposal and asked for a 60-day exten-

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IEA World Energy Outlook 2025 Quantifies Rising Global Power Demand

By James Downing

The International Energy Agency released its *World Energy Outlook 2025*, which found new emerging economies are poised to drive the near-term future of energy.

China accounted for half of oil and gas demand growth and 60% of electricity demand growth for the last decade, but going forward the markets will be driven by what happens in India, Southeast Asia and countries in the Middle East, Africa and Latin America. No country, or even group of them, is expected to come close to replicating the scale of China's energy-intensive rise.

The world continues to face security risks to oil and gas supplies, but IEA said China's dominance of rare earth minerals vital to power grids, batteries and electric vehicles now accompany those much older risks. China is the dominant refiner for 19 out of 20 energy-related strategic minerals, with average market share across those of around 70%.

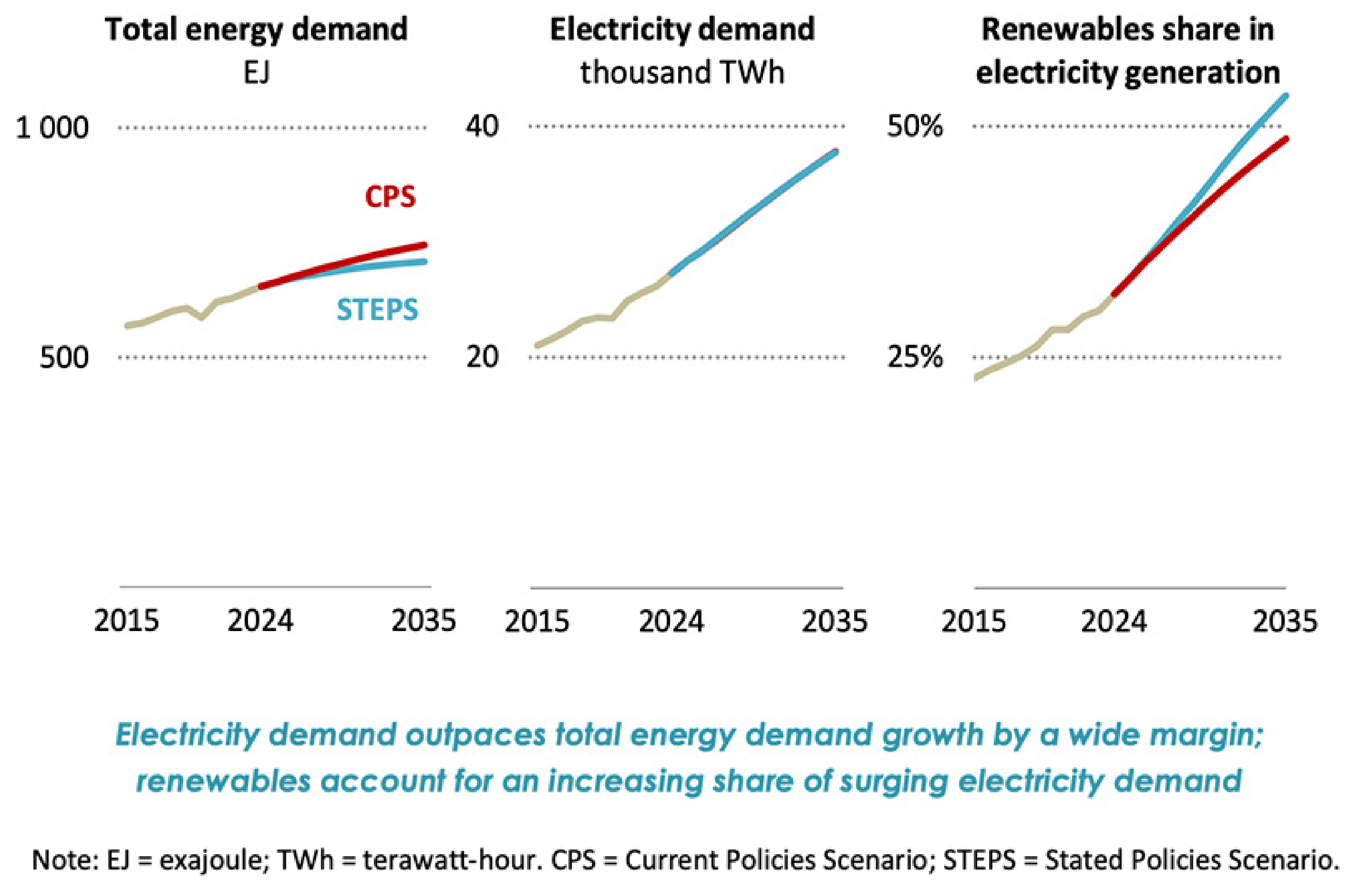
Why This Matters

The lengthy report covers all aspects of the global energy industry including oil and gas, renewables and the growing role of electricity around the world.

"When we look at the history of the energy world in recent decades, there is no other time when energy security tensions have applied to so many fuels and technologies at once — a situation that calls for the same spirit and focus that governments showed when they created the IEA after the 1973 oil shock," IEA Executive Director Fatih Birol said in a statement. "With energy security front and center for many governments, their responses need to consider the synergies and tradeoffs that can arise with other policy goals — on affordability, access, competitiveness and climate change."

Electricity is at the heart of modern economies, and its demand grows faster than overall energy demand in all scenarios that IEA ran for its report. Last year, the group said the world was moving into the "Age of Electricity"; that has already arrived, it said in the latest report.

"In a break from the trend of the past decade, the increase in electricity consumption is no longer limited to emerg-



IEA's projections for global energy demand, which is being outpaced by electricity demand growth and a growing share of renewables supplying that electricity | *IEA* ing and developing economies," Birol said. "Breakneck demand growth from data centers and AI is helping drive up electricity use in advanced economies too. Global investment in data centers is expected to reach $580 billion in 2025. Those who say that 'data is the new oil' will note that this surpasses the $540 billion being spent on global oil supply — a striking example of the changing nature of modern economies."

With the growing importance of electricity and pressures from growing demand adding to higher prices, electricity bills are rising to the top of the political agendas in many countries, the report said.

"This shift underscores a growing tension: While electrification offers long-term efficiency gains and emissions reductions, it also increases the sensitivity of movements in electricity prices, which are shaped by a complex mix of fuel costs, infrastructure investment, market design and policy choices," the report said.

Electricity is becoming a larger share of household energy spending around the world because of electrification. The report expects average household demand to grow by 25% by 2035 and 60% by 2050, with significant variations by region.

Advanced economies have a decade-long trend of demand stagnation, but households there should see it grow by 15% by 2035 and 35% by 2050.

"While increases in energy efficiency moderate consumption for appliances, the electrification of transport is a major driver of expanding electricity use in regions with supportive policy frameworks and increasing EV sales shares," the paper said. "This shift underscores the need for grid readiness and demand flexibility solutions like smart charging to manage peak demand and to improve affordability."

Developing countries will see even higher household demand growth – 30% by 2035 and 90% by 2050 — because of air conditioning that comes from rising incomes and higher average temperatures.

"Rapid growth in electricity demand brings with it a need for substantial investment across the power sector," the report said. "Grid infrastructure, in particular, is seeing a marked increase in capital spending to connect new loads, integrate new sources of electricity and enhance resilience. While rising investment does not necessarily translate into higher average system costs — especially if demand rises in parallel — the financing conditions and timing of the investment are critical."

Some things are working to lower prices, with IEA saying natural gas prices should drop in many markets as more LNG becomes available and the growth in renewable power helps bring down wholesale electricity prices.

"As electricity demand rises, the fixed costs of new infrastructure can be spread across a larger volume of consumption, potentially reducing the cost per megawatt-hour," the report said. "In some cases, this dynamic may even lead to lower electricity prices in real terms despite rising investment levels, highlighting the importance of well designed policies and market frameworks that enable efficient investment recovery while protecting consumers." ■

Tribes Urge FERC to Reject Wright's Hydropower NOPR

Continued from page 15

sion and initiation of government-to-government consultation with interested tribes before moving forward.

"Nothing in Section 403 requires the commission to undertake a rulemaking or to adopt the secretary's suggested regulatory text," they said.

The proposal conflicts with the Department of Energy's own "trust responsibilities" to tribes, they argued. The federal trust responsibility applies to all executive agencies and requires that federal actions avoid harming tribal lands and waters, they said.

"By requesting rule changes that would restrict the commission's ability to consider tribal consent or protect tribal rights in preliminary-permitting decisions, the secretary is advancing an action that is inconsistent with those responsibilities," the tribes told FERC. "DOE should instead consult with tribes before proposing any regulatory changes that could impact tribal lands or waters."

While the secretary argued the 2024 policy allows "third parties" to veto permits, the two tribes argued that framing ignores fundamental law.

"Tribal nations are not 'third parties,'" they added. "They are sovereign governments with federally protected interests in land, water, cultural and other trust resources. These interests are not speculative; they are legally recognized and enforceable."

Considering a tribe's authority to control access to its lands or use of its waters is not an improper delegation, but rather FERC performing its duty under the Federal Power Act and other federal law, they said.

The Ute Mountain Ute Tribe also argued that tribes are not third parties, but rather sovereign governments whose lands and resources are held in trust by the U.S. The 2024 policy correctly applied the law, it said.

"DOE's proposed rule would compel the commission to disregard that obligation by forcing the issuance of permits even when tribes have explicitly withheld consent," the tribe said. "Tribal opposition is not a 'veto'; it is the exercise of sovereign authority. By denying permits in those circumstances, the commission honors its trust duty and promotes orderly, cooperative energy development."

While preliminary permits do not allow developers to disturb any land, they do block tribal governments from pursuing their own developments at sites, which has tangible economic and jurisdictional consequences, the tribe said. ■

Transmission Delays Mean Higher Costs for Customers, Study Finds

By James Downing

For every $1 billion in transmission investments that is delayed, consumers lose between $150 million and $370 million in net benefits per year of delay, according to a *study* by Grid Strategies released Nov. 12.

"That's a pretty impactful amount when it comes to this debate around affordability, and it speaks for the need to get more transmission built faster in order to lessen the impact on consumers," WIRES Executive Director Larry Gasteiger said in an interview Nov. 14. WIRES commissioned the study.

The losses come from lower reliability, diminished access to lower-cost generation and the lack of efficiency from new transmission lines, the report says.

Grid Strategies analyzed eight regional transmission portfolios from ERCOT, MISO, NYISO and SPP. It extracted total reliability and economic benefits identified in each portfolio and converted them to annualized benefits and calculated annualized costs from the transmission planners' assumptions.

Transmission projects face delays from factors including siting and permitting and other regulatory delays, Gasteiger said.

"There are supply chain issues that have developed, particularly over the last five to six years, where it just takes longer to get the items needed in order to build transmission," Gasteiger said. "There's been a lot of regulatory uncertainty, frankly, around transmission, in terms of what the rate of return is going to be, what the incentives are for transmission, and there's no question that that ultimately impacts the timing on getting transmission built."

| Grid Strategies

When transmission owners do not know what the regulatory framework is going to be, that causes risks, which in turn leads to delays, he added.

A little regulatory uncertainty is baked into the system, and the industry is facing some as FERC undergoes a leadership shuffle now.

"We're waiting to see how this new commission handles issues around affordability," Gasteiger said. "And I think one of the factors that has to come into play is that building out more transmission can have some serious positive impacts associated with consumers, such as gaining access to cheaper, more affordable power sources, generation sources, better reliability and things of that nature."

New Chair Laura Swett has participated in a cost allocation order already, denying a complaint from the Kentucky Public Service Commission and allowing American Electric Power's tariff to spread the costs of supplemental projects in PJM across all its utilities in the market. (See *FERC Rejects Kentucky Complaint Against AEP's Tx Cost Allocation*.)

One major issue the new commission will have to deal with is Order 1920 implementation, as the regions file their compliance filings with the planning and cost allocation reforms passed by FERC during the previous administration.

"It's going to be interesting to see whether the commission affords a lot of flexibility in the regions, or do they want to try and use a much more standardized approach?" Gasteiger said. "I don't know. I can't predict where they will come out on that, but in a way, you almost have the feeling like that some of the issues that were dealt with in 1920 have been eclipsed to some extent, by focus on things like the ANOPR that just came out from DOE."

The Advance Notice of Proposed Rulemaking asks FERC to assert jurisdiction over the interconnection of large loads, which are driving significant demand growth, often in regions that had seen effectively no real growth for decades.

Why This Matters

As load growth and affordability are center stage in the industry, the report makes the case for timely investment in new transmission to address the former while ensuring the latter.

"With load growth, the more customers you have signing on to the system, the more you can spread the costs out among those customers, so that winds up having the ability to kind of reduce costs generally, because you have more people paying for it," Gasteiger said. "There are a lot of issues around getting access to cheaper power for all of those resources. And the administration's made clear it is focused on the effort to help integrate AI and data centers, and the only way you're really going to be able to do that is to have more transmission built as well."

The report spends time discussing load growth, which it says has led to a growing consensus around the need for new large-scale transmission investment. FERC's 2024 State of the Markets Report said that 1,000 miles of new lines were placed into service over the last year because of higher demand, an amount second only to projects aimed at reliability, it noted.

That trend is going to continue based on projects in the works, as NERC summarized in its 2024 Long-Term Reliability Assessment.

"The 2024 LRTA reports there are 28,275 miles of transmission (>100 kV) planned or under construction through 2034," according to the Grid Strategies report. "This estimate is almost 10,000 miles higher than the 2023 LTRA 10-year projections and is well above the average of 18,900 miles over the past five years of NERC's LTRA reporting." ■

Brattle Study Finds Similar PRMs Under Alternative Western RA Footprint

Potential RA Program Consisting of EDAM Participants Examined Against WRAP

By Elaine Goodman

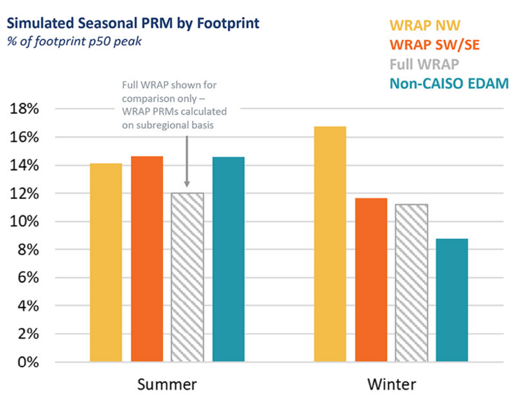
As entities explore alternatives to the Western Resource Adequacy Program (WRAP), a new Brattle Group study examines the impact on planning reserve margins of an RA program encompassing expected participants in CAISO's Extended Day-Ahead Market.

Brattle prepared the *report* for the Balancing Authority of Northern California, Idaho Power, the Los Angeles Department of Water and Power, NV Energy, PacifiCorp, Portland General Electric (PGE), Public Service Company of New Mexico (PNM), the Sacramento Municipal Utility District and Seattle City Light.

Those nine entities form a "non-CAISO EDAM" footprint that is the focus of the study. Some of the entities have signed agreements to join EDAM, while others are awaiting regulatory approval to do so or have said they are leaning toward EDAM.

The study simulated winter 2027/28 and summer 2028 planning reserve margins for an RA program covering the non-CAISO EDAM footprint, compared with footprints for WRAP's Northwest and Southwest subregions.

For summer, Brattle found the PRM was similar among the three footprints, with each falling between 14 and 15%. The authors said summer reliability risks are comparable for the three footprints.



A Brattle Group study compared planning reserve margins for the WRAP versus an alternative regional resource adequacy program footprint. | *Brattle Group*

More variability was seen in winter PRMs: from almost 17% for WRAP's Northwest region to nearly 12% for WRAP's Southwest region and about 9% for the non-CAISO EDAM region. The authors attributed the non-CAISO EDAM footprint's lower PRM to higher regional resource diversity.

"The non-CAISO EDAM footprint offers significant resource adequacy benefits, on par with and possibly exceeding the resource adequacy benefit of the current WRAP footprint," the report authors said.

Planning reserve margin volatility was one concern utilities cited in deciding whether to commit to Western Power Pool's WRAP or to withdraw from the program.

With an Oct. 31 deadline to commit to the program's first binding phase in winter 2027/28, WRAP won commitments from 16 entities, while five entities withdrew. (See *WRAP Wins Commitments from 16 Entities* and *4 Entities Join NV Energy in Exiting WRAP, While Idaho Power Commits*.)

Many of those that committed to WRAP plan to join SPP's Markets+, which requires WRAP participation. But there were exceptions: Idaho Power has committed to WRAP despite saying it is leaning toward EDAM.

NV Energy, PGE and PNM are expected to join EDAM; each announced their withdrawal from WRAP. And in October, NV Energy representatives revealed that talks are underway regarding an alternative resource adequacy program. (See *EDAM Participants Exploring Potential New Western RA Program*.)

Western Power Pool (WPP) wasn't involved in the study and hasn't fully reviewed the results, according to WPP Chief Strategy Officer Rebecca Sexton.

"In our initial review, the study seems to support WRAP's foundational premise that there is significant benefit to customers from participation in a broad, WRAP-wide footprint," Sexton said in an email.

Why This Matters

Results of the Brattle study could provide reassurance to EDAM-aligned entities that are exploring an alternative to the Western Resource Adequacy Program.

Sexton noted that participants representing more than 58 GW of Northwest and Southwest load and a broad mix of resource types have committed to WRAP. She said WPP would welcome proposals based on the study's findings that would enable study sponsors to participate in WRAP.

Brattle modeled loads and resources for the different footprints for winter 2027/28 and summer 2028.

Looking at planning reserve margins on a monthly basis, Brattle found that PRMs for the WRAP footprints were lower than that of the non-CAISO EDAM footprint in June, and were similar or lower in July. But PRM for non-CAISO EDAM was the lowest among the three footprints in August, which along with July is considered a high-risk month.

For the winter months, the non-CAISO EDAM footprint had the lowest PRM among the three footprints in November, December, January, February and March.

The Brattle study used WRAP's methodology to look at zonal resource adequacy needs and resource capacity accreditations. Brattle also recommended fine-tuning the WRAP methodology by including transmission limits within the footprints, temperature-dependent thermal outage rates, and improved hydro and weather modeling.

Adding these enhancements to the WRAP methodology "would likely reveal additional risks and yield a more complete assessment of regional RA needs," the report said. ■

BPA Looks to Fill 155 Positions After Hiring Freeze

By Henrik Nilsson

The Bonneville Power Administration has resumed hiring after workforce reductions as part of President Donald Trump's efforts to slim down the federal government, Deputy Administrator Suzanne Cooper said during the agency's quarterly business review.

After receiving authority to fill critical functions, BPA resumed hiring in September and is looking to fill 155 positions. To date, the agency has posted 122 job openings, Cooper said during BPA's fourth quarterly business review on Nov. 13. Cooper filled in for Administrator John Hairston, who had a scheduling conflict.

"The response has been overwhelming," Cooper said. "So far, we've received more than 3,450 applications, and we've made 49 selections. We are ecstatic about the level of interest, especially for positions that are typically difficult to fill."

BPA staff received a "deferred resignation" buyout offer in January from Trump's unofficial Department of Government Efficiency, immediately setting off alarms in the electricity sector about the impact on the region's grid reliability.

About 200 agency employees — or 6% of the workforce — accepted the buyout offer, while 90 job offers had been rescinded following a federal hiring freeze announced Jan. 20, according to BPA. (See *BPA Exempted from Federal Staffing Cuts, Hairston Says*.)

Despite workforce challenges, BPA continued work on 23 projects as part of a $5 billion portfolio the agency expects will add more than 6,000 MW of transmission capacity. The projects are expected to be completed by 2035, Cooper said.

Why This Matters

The new directives will allow BPA to fill critical positions after the electricity industry raised concerns about grid reliability following the federal hiring freeze earlier in 2025.

Aerial view of the Bonneville Dam | *Shutterstock*

"When including other planned projects designed to sustain our existing assets, BPA's total projected grid investment for the next 10 years is approximately $15 billion," Cooper said.

BPA has launched other initiatives aimed at boosting capacity, such as the Grid Access Transformation Project (GAT), which it launched after pausing certain transmission planning processes to consider changes in how it will tackle 65 GW of transmission service requests. (See *Utilities Back Some BPA Transmission Updates, Hesitate on Others*.)

"We are also benefiting from the work done in recent years to modify our large generator interconnection process," Cooper said. "We move to a first-ready, first-served approach that will improve … interconnection queue processing and address backlog. We plan to complete our first generator interconnection cluster study in January of 2026. This cluster study represents 167 customer requests and more than 61 GW of generation."

BPA's entrance into SPP's day-ahead Markets+ in October 2028 will further "optimize the use of our existing transmission and generating assets, as well as give us accurate data regarding our capacity needs, which we expect will help inform future investment," Cooper added.

BPA hosted the quarterly business review shortly after committing to the Western Resource Adequacy Program's first financially "binding" season covering winter 2027/28. BPA was one out of 16 entities committing to WRAP's first binding season. Five utilities withdrew from the program. (See *WRAP Wins Commitments from 16 Entities*.)

"BPA continued to see the near- and long-term value of the Western Power Pool's resource adequacy program, which remains one of the largest such programs in the country," Cooper said. "While a few utilities opted to exit the program, WRAP remains viable and continues to provide critical tools and resources to help address current and future reliability challenges."

Financial Outlook

Tom McDonald, BPA's chief financial officer, provided an update during the Nov. 13 call, saying that "despite difficult hydrological conditions, BPA met its key performance indicators this year. The well below-average water supply, however, tested our financial risk mechanisms."

In fiscal 2025, BPA achieved net revenues of $74 million, $4 million above target. The result largely was driven by transmission service revenues, which came in $22 million over target. However, this is $211 million below the rates-based forecast of $285 million, according to a news release. ■

Xcel Seeks Extension for Comanche Coal Plant from Colorado Regulators

Outage at Unit 3 Prompts Request to Delay Unit 2 Retirement

By Elaine Goodman

Xcel Energy, along with Colorado Gov. Jared Polis' administration, wants to keep Unit 2 of the coal-fired Comanche Generating Station running a year longer than planned, mainly because of malfunctions at Unit 3.

A *petition* filed Nov. 10 with the Colorado Public Utilities Commission asks to keep Unit 2 available through 2026, a year past its scheduled retirement date of Dec. 31. The petition was filed by the Colorado Energy Office, the state Office of the Utility Consumer Advocate, PUC trial staff and Xcel Energy subsidiary Public Service Company of Colorado.

The request follows the unexpected outage of Unit 3 that began Aug. 12. Xcel said the unit was extensively damaged and is expected to remain offline until at least June.

"The cause of the outage, the steps necessary to repair it and the costs are unknown at this time," according to a fact sheet on the Colorado PUC website.

With a nameplate capacity of 750 MW and accredited capacity of 415 MW, Unit 3 is the largest of Comanche's three units. It is to retire by Jan. 1, 2031. Unit 2 has a nameplate capacity of 335 MW and an accredited capacity of 296 MW, the petition said. The 335-MW Unit 1 retired in 2022.

The coal-fueled steam units are in Pueblo, about 110 miles south of Denver.

Why This Matters

Arguments for and against the request to postpone the retirement of Comanche Unit 2 may mirror the national debate over the Trump administration's orders to keep coal-fired power plants open.

Extended Outage

Xcel's petition to postpone the retirement of Unit 2 "is a direct response to the unexpected outage of the Comanche Unit 3," the PUC fact sheet said.

But other factors are contributing to the request, the petition said. The peak demand forecast in PSCo territory has increased to about 7,150 MW for summer 2026. A forecast made in 2024 predicted the summer 2026 peak would be about 6,950 MW.

Supply chain and tariff issues are hindering generation and storage projects, the petition added. An updated analysis of accredited capacity showed that PSCo needs more generation and capacity to meet demand.

"The continued operation of Comanche Unit 2 in 2026 is the most cost-effective approach to providing needed electricity for the system," the petition said.

While market purchases would be one option for replacing the lost output of Unit 3, "such purchases are often expensive and volatile, especially during high-use times, such as winter cold spells, which can lead to gas price spikes," the PUC fact sheet said.

If the PUC approves a yearlong extension to Unit 2 operations, PSCo would report to the commission by March 1 on the status of Unit 3. The report would discuss short-term resource options and "appropriate operational parameters" for Unit 2, especially after Unit 3 returns to service.

A more detailed report would be filed by June 1, including updated load and resource projections and loss-of-load calculations. The six-month planning period would give PSCo time to propose longer-term resource options, potentially including "consideration of updated retirement dates for Comanche Unit 2 and Comanche Unit 3," the petition said.

Cost Concerns

Unit 3 has been plagued with problems since operations began in 2010. From mid-2010 through 2020, the unit averaged 91.5 outage days a year, according to a March 2021 report from the PUC. A 2020 outage lasted much of that year and extended into 2021.

"Plagued by failures and outages, Comanche 3 has been an albatross around the neck of Xcel ratepayers for more than a decade," Erin Overturf, clean energy director at Western Resource Advocates, said in response to PSCo's petition. "This request to delay the long-planned retirement of Comanche 2 will lead to increased costs for utility customers at a time when people are already economically struggling."

The Sierra Club said in a statement that any decision to keep a coal plant running for reliability reasons "must be strictly monitored and narrowly tailored to avoid more unnecessary costs and pollution."

"The administration and Xcel's proposal would guarantee only one thing: Comanche 2 will run for another year, which means more air pollution in Pueblo and higher electricity bills for everyone," said Margaret Kran-Annexstein, director of the Sierra Club's Colorado chapter.

The PUC approved early retirement dates for Comanche Units 1 and 2 in 2018. Xcel announced in 2022 its plans to exit from coal-fired power plants by the end of 2030 as part of its clean energy transition.

The Trump administration has had other ideas about coal plants set to retire. In late May, the Department of Energy issued an emergency order to reverse the impending retirement of the J.H. Campbell coal plant in Michigan. The order directed the plant to remain ready to operate because of a shortage of electricity and capacity to generate electricity.

DOE in August ordered Campbell to remain available through Nov. 19. In an Oct. 30 filing, plant owner Consumers Energy said Campbell had racked up $80 million in net costs since late May staying online. (See *J.H. Campbell Tab Rises to $80M on DOE's Stay Open Orders*.) ■

FERC Denies CAISO OATT Interconnection Rehearing Requests

Commercial Interest Points at Stake

By David Krause

FERC has denied rehearing requests regarding approved revisions to CAISO's Open Access Transmission Tariff generator interconnection procedures, which contesting parties said rely partly on "subjective and discriminatory criteria."

Calpine, Clean Energy Associations, Dynegy Marketing and Trade, and Vistra filed the rehearing requests in October 2024. On Nov. 7, FERC *denied* the requests and clarified the discussion in its queue reform order.

CAISO proposed the OATT interconnection revisions because of an "unprecedented numbers of interconnection requests" resulting from California state regulatory requirements and policies, the order said.

The revisions included a zonal approach that prioritizes interconnection projects in areas with existing or planned transmission capacity. The approach provided four cluster study criteria, including a "commercial interest" score, which is up to 30% of a project's overall score.

The rehearing parties claimed that commercial interest points create opportunities for potential undue discrimination or preference, specifically by allowing load-serving entities to allocate commercial interest points to affiliates. That allows for the disparate treatment of LSEs vs. non-LSEs and creates an impact on small LSEs, the parties argued.

| *Shutterstock*

The commission found these claims "unpersuasive" because CAISO's revisions "balance LSEs' role in resource procurement with appropriate tariff limitations on LSEs' ability to award points, including limitations on points that may be awarded to affiliates," the order says.

FERC disagreed with the rehearing parties' claim that LSEs would be able to control access to the grid by using "subjective and discriminatory criteria to assign commercial interest points in an anticompetitive manner."

The rehearing parties said allowing LSEs to award commercial interest points violates the Federal Power Act, which prohibits undue discrimination. The parties also said the commercial interest points process erodes "two longstanding commission policies that provide non-discriminatory and comparable access to all wholesale users and ensure interconnection rules are not unduly discriminatory or preferential."

FERC pointed out the Federal Power Act does not prohibit all discrimination, only "undue discrimination."

"Discrimination is undue when similarly situated customers are treated differently," the commission said in the order. "Here, no party on rehearing has provided any persuasive explanation that similarly situated interconnection customers will be treated differently under the revised tariff."

CAISO said rejecting commercial interest points would "significantly diminish the value of its proposal and result in more ties," the order says.

The approved OATT revisions will allow CAISO to select and move forward with proposed generating facilities for reliability and public policy purposes, the order says. ■

'There's Room for Everybody': California Ports Prepare for OSW Development

CEC Approves About $9M for Offshore HVDC Designs

By David Krause

At a two-day workshop held by the California Energy Commission, offshore wind experts and fishermen identified challenges associated with building offshore wind turbines in Humboldt Bay and other parts of the coastline while not displacing the fishing industry.

Recent federal policy changes have left the future of the renewable energy resource in limbo, but California officials continue to push ahead with offshore wind design and development plans. (See *CEC Approves 5 Offshore Wind Projects at California Ports*.)

At the CEC's Nov. 13 workshop, engineers, fishermen, developers and port officials, among others, talked about the path towards a future in which offshore wind turbines send electrons to the Golden State's grid.

"It really takes a lot of our California ports working together to be able to realize this vision," said Matt Trowbridge, a vice president with infrastructure design company Moffatt & Nichol.

No existing port terminals along the West Coast can support the equipment that's needed to build offshore wind facilities, he said.

"How much of these manufacturing sites that are building the components needed for offshore wind are going to be in the U.S. and in California, and how many are going to come from other places?" Trowbridge asked. "What's the right amount of in-state fabrication that will allow this industry to move?"

Why This Matters

California officials want to develop 25 GW of offshore wind energy capacity, but doing so requires rebuilding many of the state's largest ports.

The fishing industry wants certainty that it will continue to be a viable career for people when offshore wind farms operate in the state.

"Fishing is one of the oldest industries in the United States," said Ken Bates, vice president of the Humboldt Fishermen's Marketing Association. "For old fishermen like me and the younger guys that are looking at this, nobody understands how they're going to survive ocean industrialization."

Humboldt Bay is the second-largest estuary in California and a huge nursery ground for tons of commercial species, he said.

Ports are the starting and stopping point for fishing operations: When fishing boats come back into the port, "there's a whole other set of things that they require to keep their businesses running and to get the fish processed for the customer," Bates said.

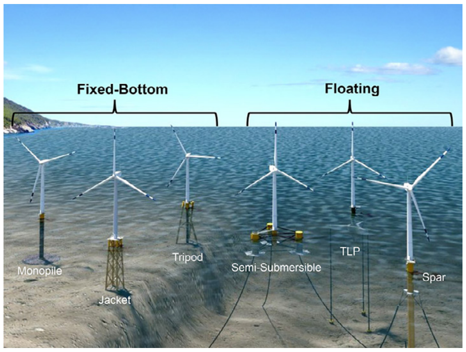
"And in the last 25 to 30 years, the priority of the fishing industry and its position in the pecking order, has moved down and down and down. Do we place any value on having a fish processing plant in a little port? There's room for everybody."

Another challenge with building offshore wind in California is ensuring that wind farm developers have more certainty about the amount of transmission infrastructure that will be available for offshore projects, said Martin Christensen, senior onshore works manager with Vineyard Offshore.

The Humboldt region does not have enough transmission capacity to bring the power from offshore wind projects to load centers, Christensen said.

"Right now, I think Humboldt can only accept, like, 150 MW, and our project's going to be between 1 and 2 GW," Christensen said. "The math just doesn't add up."

Most existing offshore wind farms are built with fixed-bottom turbines, which anchor using piles or truss jackets, Trowbridge said. But in the Pacific Ocean, the outer continental shelf drops off near California's coastline, which makes fixed-bottom turbines inadequate. California will need to therefore install floating turbines that connect to the seabed using mooring lines and anchors.



California will require floating offshore wind turbines, rather than fixed-bottom turbines, because the coastline has deep water near the shore. | *NREL*

CEC Approves Port Funding

At the CEC's Nov. 12 business meeting, the commission approved about $9.2 million for research on deepwater HVDC substations and ocean monitoring methods capable of detecting entangled debris.

As part of the funding, Alliance for Sustainable Energy will develop a standardized concept design for a floating HVDC substation. California's offshore wind farms may be in water that is 1,800 to 4,300 feet deep, making fixed-bottom substations infeasible, the CEC's *resolution* says.

HVDC equipment can be affected by the motions of a floating platform, so an HVDC substation's mooring system must be designed to constrain the motions. This design results in a complex system engineering problem that requires balancing considerations in platform stability, HVDC equipment robustness, mooring stiffness and cable excursions, the resolution says.

Alliance for Sustainable Energy will develop the first open-source floating HVDC substation design, which should reduce the cost of the substations and make them less environmentally harmful. ■

Texas PUC Hints at Revisiting ERCOT Conservative Operations

Regulators Approve Grid Operator's Budget, Admin Fee Reduction

By Tom Kleckner

Texas regulators have *approved* ERCOT's methodologies for determining minimum ancillary services for 2026 while hinting at the same time that they are considering discontinuing the use of conservative operations (*54445*).

Potomac Economics, which serves as ERCOT's Independent Market Monitor, has said the grid operator's practice of setting aside large amounts of operating reserves leads to inefficient scarcity prices that the energy-only market relies on to attract investment. (See *Patton Calls on ERCOT to Operate its System Less Conservatively*.)

"I think we do need to look at moving away potentially from how conservatively we've been operating the grid," Thomas Gleeson, chair of the Public Utility Commission, said during its Nov. 6 open meeting. "I think we need to talk through all that because we've committed to kind of having a refocus on affordability and costs. Every season we get away from [February 2021's] Winter Storm Uri, I think we need to be asking ourselves, given where we are today, 'Does our methodology, does our procurement practice, really match what we think we need?' I think we need to start asking those questions."

The PUC directed ERCOT to use conservative operations in 2023 after a flurry of conservation calls.

Commission staff *said* ERCOT's current ancillary services and the future deployment of Dispatchable Reliability Reserve Service (DRRS) "provide ERCOT sufficient" ancillary service products to comply with NERC requirements and respond to "inherent system variability and uncertainty" (*55845*).

Staff recommended the PUC minimize the number of significant market design changes during the first several months after the Real-time Co-optimization + Batteries project goes live in December.

RTC+B will "likely produce a fundamental shift in the procurement and deployment of AS, and the industry will be best served if the commission observes those changes and uses RTC-based data to inform subsequent changes to future AS methodologies," staff said.


New Commissioner Morgan Johnson at her first PUC meeting | *AdminMonitor*

The ERCOT Board of Directors endorsed the methodologies during its September meeting. The grid operator will use a probabilistic methodology — an analytical approach incorporating randomness and uncertainty by assigning probabilities to outcomes and events — to calculate hourly ERCOT contingency reserve service (ECRS) and non-spinning reserve service quantities. The probabilistic model aligns ECRS and non-spin requirements with the risk profile, where higher risk equals a higher requirement and *vice versa*. (See *ERCOT Board Approves AS Procurement for 2026*.)

The Monitor opposed the methodology during the stakeholder process, saying it was misaligned with reliability outcomes. The IMM's compromise position included halving the six-hour forecast horizon for determining non-spin and using a one-hour discharge horizon for storage resources rather than four hours.

LCRA Wins 2nd TEF Grant

The commission approved the Lower Colorado River Authority's eligibility for a Completion Bonus Grant (CBG) of up to $22.56 million in performance-dependent funds over a 10-year period under the Texas Energy Fund (*57937*).

PUC staff and LCRA *signed the agreement* Nov. 10, the first under the TEF's completion bonus program for projects that connect to the grid before June 1, 2029. LCRA's Timmerman Power Plant Unit 1 was synchronized in August.

Two other applicants in the program are seeking loans totaling $23.06 million, staff said, for projects offering a combined 360 MW.

"I think it's fair to say this is working well," Gleeson said.

The unit provides ERCOT 190 MW of dispatchable generation. A second unit is expected to become operational in 2026, adding another 190 MW of capacity to the grid.

Annual payments are contingent upon the plant's performance as measured by ERCOT during an annual "test period" and compared to the performance of a reference group of other generation resources in the region. Timmerman Unit 1's first test period will run June 1, 2026, to May 31, 2027.

The PUC announced in October the *largest loan* under the TEF's In-ERCOT Generation Loan Program, a 20-year, $1.12 billion loan for about 60% of Competitive Power Ventures' 1,350-MW natural gas unit in West Texas. The unit has a targeted operational date in 2029.

With the fifth grant under the program, the TEF has now financed more than 3,100 MW of dispatchable power. Twelve more projects are moving through the In-ERCOT program's due diligence review, representing nearly 6,000 MW of additional generation.

PUC Approves ERCOT Budget

The commission *endorsed* ERCOT's biennial 2026-2027 budget and system administrative fee, adding large load interconnections to a list of priority performance measures that must be met (*38533*).

As approved by the ERCOT board during its June meeting, the grid operator is authorized to spend $485.87 million in 2026 and $585.04 million in 2027. The PUC granted the grid operator's request to increase an existing $100 million revolving line of credit by $25 million and to reduce its administrative fee from 63 cents/MWh to 61 cents. (See "Board Approves $1.07B 2-year Budget," *ERCOT Board of Directors Briefs: June 23-24, 2025*.)

The large load performance measure was added to staff's original recommendations, all designed to support ERCOT's implementation of the 2026 reliability standard assessment: deployment and stabilization of the RTC+B project; enactment of *Senate Bill 6*, the 2025 legislation overhauling several grid regulations; development of DRRS; and implementation of the ancillary services study findings.

ERCOT staff agreed to work with PUC staff to develop the performance measure targets. "We have a lot of ideas," General Counsel Chad Seely told the commissioners.

In other actions, the PUC:

- adopted *revisions* to ERCOT's standard generation interconnection agreement (SGIA) that require generators to pay interconnection costs that exceed a "reasonable allowance" established by the commission, effective Jan. 1, 2026. Other changes include revisions adding plain language and clarity to the SGIA; requirements regarding the sharing of contact information between generators and transmission service providers; and requirements that generators comply with the Lone Star Protection Act (*58211*).
- approved an *amendment* to established wholesale market power rules that removes the exemption currently preventing a generation entity controlling less than 5% of ERCOT's total installed capacity from being considered to have market power, commonly referred to as the "small fish rule" (*58379*). ■

IESO Implementing 'True-up' on Renewed Market Rules

By Rich Heidorn Jr.

After seven months of operations under its Market Renewal Program, IESO is doing some housekeeping, implementing "non-substantive" changes that it said will "improve clarity" and "better align the market rules with the correct functioning" of the nodal market.

The changes, approved by the IESO Board of Directors on Oct. 24, are effective Dec. 3.

The Renewed Market, which launched May 1, created a financially binding day-ahead market (DAM) and about 1,000 generation, load and intertie pricing nodes to replace its provincewide price. (See *Ontario Nodal Market Nearing 'Steady State' After Nearly 4 Months*.)

Some of the changes remove transitory provisions that allowed both the Renewed Market rules and the legacy market rules to be in effect concurrently. "They do not reflect changes in design principles and are limited to typographical, cleanup, clarifications or computational corrections," IESO *said*.

In addition to general cleanup items, the changes affect sections on settlements, market power mitigation, and market and system operations.

Market Power Mitigation

The changes (*MR-00484-R00*) reduce the default value for maximum starts per day from 10,000 to one; remove the "unnecessary administrative burden" on market participants to disclose affiliated entities that have limited or no ability to control or influence a market participant; and codify IESO's obligation to publish potential constrained areas.

Market and System Operations

The changes to Chapter 7 of the market rules (*MR-00484-R01*):

- prohibit generator offer guarantee-eligible resources from increasing offer prices for energy and operating reserves (OR) during the first 30 minutes of a dispatch hour of the real-time market unrestricted window;
- require market participants to revise single-cycle mode status to align with the requirements and duration of commitments that span across midnight; and
- add a limit for electricity storage resources offering OR in the opposite direction of OR supply during the subsequent dispatch hour in the energy market. The limit was inadvertently omitted.

Settlements

Settlement provisions of the market rules were revised (*MR-00484-R02*) to:

- amend the hourly operating reserve settlement amount by dividing the quantities by 12;
- clarify the eligibility for the DAM balancing credit based on day-ahead schedules;
- delete the offer/bid substitution for DAM make-whole payments (MWPs), which is not applicable;
- modify the language of the DAM MWP ineligibility for called capacity exports with the same language in the real-time MWP provisions;
- insert the "dispatchable load" resource type within a provision for the real-time MWP reversal charge;
- amend the formula for the hourly uplift settlement amount to add a missing variable; and
- amend the formula for the DAM reliability scheduling uplift by inserting brackets to clarify the summation function.

Miscellaneous Cleanup Items

MR-00484-R03 deletes the obligation for IESO to review the capacity prudential requirements at least once every three years.

MR-00484-R04 corrects typographical and grammatical errors, adds cross-references and italicizes defined terms.

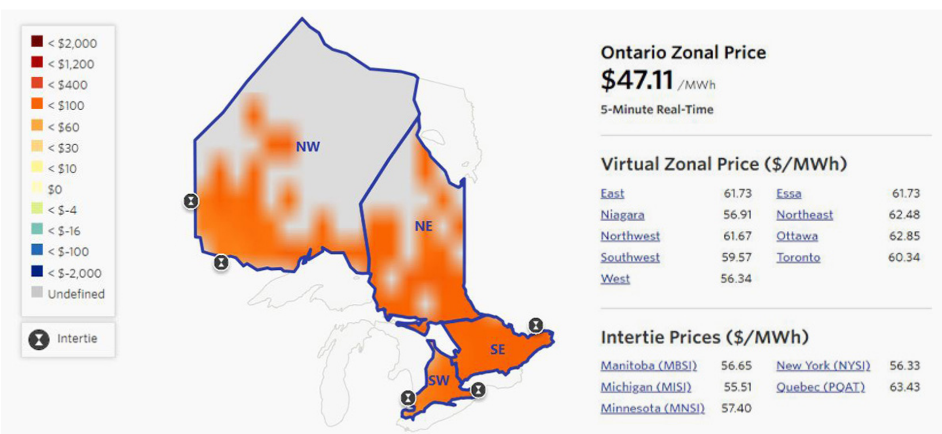
MR-00484-R05 removes transitory provisions to reflect the switch from the legacy market to the Renewed Market, including:

- "Section A" rules at the beginning of each chapter, which allowed both the renewed market rules and the legacy market rules to be in effect concurrently;
- sections A.1 and B.1.1 in each chapter of the market rules (where applicable); and
- the defined term "market transition error," which is no longer required.

It also modified the definitions of the terms "market transition," "market transition completion" and "Renewed Market rules." ■

Why This Matters

IESO says its nodal market will save Ontario $700 million over the next decade through reduced out-of-market payments and increased efficiency.



Real-time prices on Nov. 11 at 12:25 p.m. | *IESO*

IESO Board OKs Rule Changes Ahead of Capacity Auction

By Rich Heidorn Jr.

IESO will implement new rules for breaking ties and reducing unfulfilled commitments in its capacity market ahead of its next auction Nov. 26-27.

The changes, approved by the IESO Board of Directors on Oct. 24 and effective Nov. 17, include a multistep tie-break process to optimize the capacity auction clearing process (*MR-00488-R00*) and an amendment to make it easier for participants to transfer capacity obligations and harder to buy them out (*MR-00483-R00*).

The board acted following favorable reviews by its Technical Panel. (See *IESO Capacity Market Rule Changes Advance*.)

Capacity Obligations

Resources selected in the annual capacity auction are expected to participate in the energy market unless they buy out or transfer their obligations. But some resources fail to fulfill their obligations because, for example, they did not complete the registration requirements. (See *IESO Seeks to Shore up Capacity Market*.)

Unfulfilled obligations reduce the capacity available and distort clearing price signals, the ISO says.

What's Next

IESO will release the results of its capacity auction Dec. 4.

With the changes, suppliers who fail to complete the registration process no longer will have the option of simply forfeiting their deposits and will be required to buy out their obligations. In addition, the buyout charge is increasing from 33 to 50% of the obligation value.

The revisions also will remove the requirement that obligations can be transferred between resources only with the same attributes.

The board *said* the changes, recommended unanimously by the Technical Panel, will improve reliability.

Tie-break Methodology

A tie occurs when two or more participants offer the same price for the last available quantity of capacity in a zone.

Under the previous rules, the ISO used time stamps to select the bid submitted first to break the tie. The new rules created a three-step process to award an equal share in step 1 and apply a proportional allocation in step 2, based on what's left over from step 1. Capacity remaining after step 2 will be allocated by time stamp rank.

In its approval, the board said the changes will result in a "more equitable" tie-break solution.

Auction

The Nov. 26-27 auction, which will seek capacity for the periods beginning May 1 and Nov. 1, 2026, is open to existing and non-committed demand response, generation, energy storage and import resources. Results will be posted Dec. 4.

The 2024 *auction* for summer 2025 (May 1-Oct. 31) procured 1,987.9 MW at $332.39/MW-day in all zones except the Northeast and Northwest, which priced at $195/MW-day. For the winter obligation period (Nov. 1, 2025, to April 30, 2026), IESO procured 1,478.4 MW at $139/MW-day in all zones. ■

The 68-MW White Dog Falls hydroelectric project in Northwest Ontario is one of Ontario Power Generation's 66 hydroelectric stations on 24 river systems. | *Ontario Power Generation*

ISO-NE Introduces Approach to Modeling Gas Constraints

By Jon Lamson

ISO-NE *outlined* its planned approach for accounting for resources' gas supply limitations in its new capacity accreditation framework at the NEPOOL Markets Committee meeting Nov. 13.

The incorporation of regional gas constraints into the RTO's accreditation process is an important part of the RTO's capacity auction reform (CAR) project, as the current accreditation process does not account for these limits.

Gas resources make up the largest group of generators in the region, accounting for 55% of generation in 2024 and 44% of capacity awards in the most recent forward capacity auction. Changes to the accreditation methodology for gas-only resources could have significant implications for overall capacity prices in the region, capacity revenues available to gas-only resources and incentives for gas generators to sign firm fuel contracts.

Why This Matters

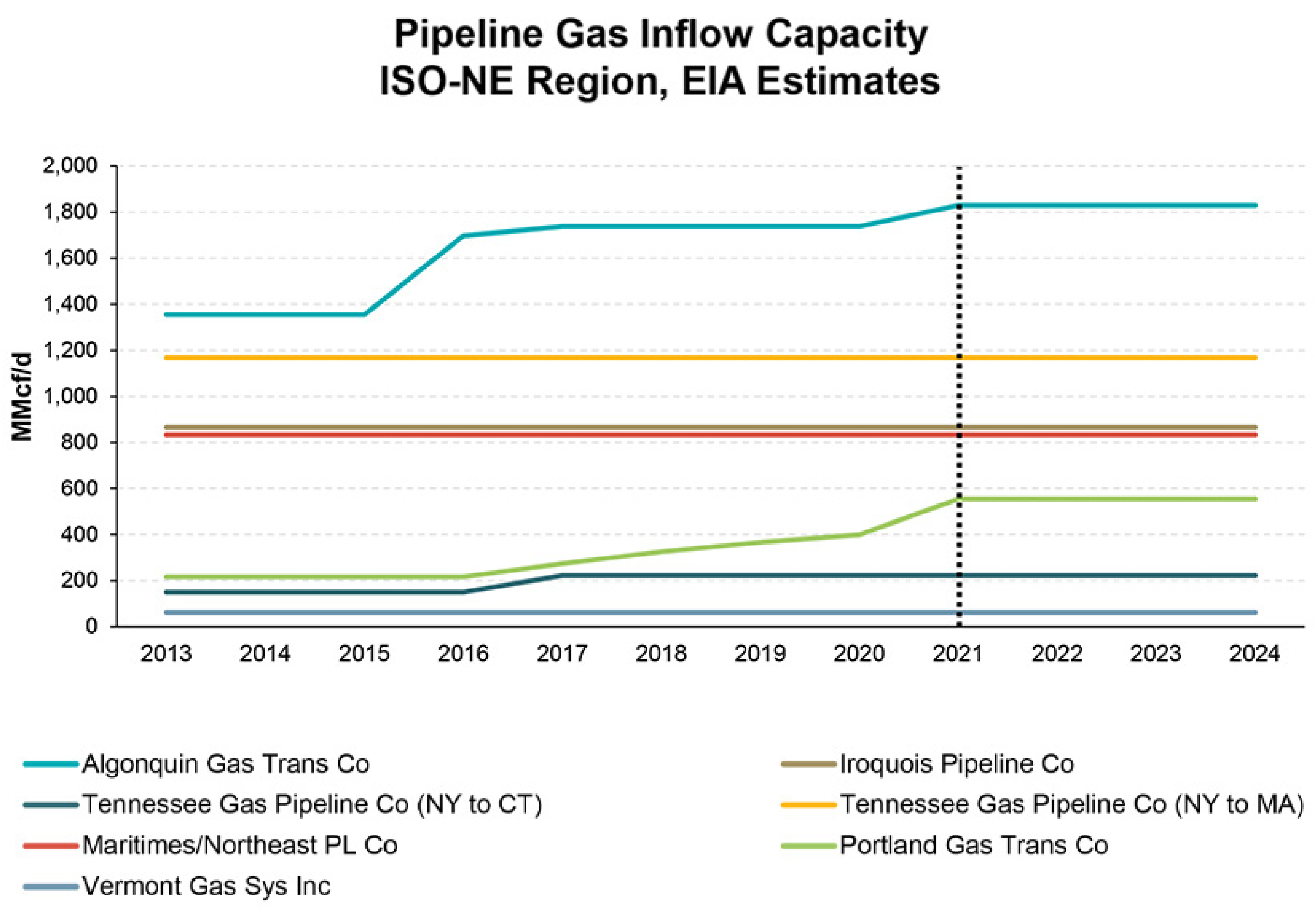
ISO-NE's approach to accounting for regional gas constraints could have significant effects on incentives for generators to firm up their fuel supply.

Under the CAR accreditation framework, ISO-NE plans to deploy a gas capacity demand curve reflecting "the diminishing reliability impact of non-firm capacity due to the system-wide gas constraint."

Steven Otto, manager of economic analysis at ISO-NE, said the downward-sloping gas capacity demand curve would be "analogous to the existing export-constrained capacity demand curve design."

In the winter, when gas resources face limited access to gas, the resources would be compensated at a lower price than other capacity resources, he said.

"In conjunction with the simultaneous clearing of the system-wide demand



New England pipeline Inflow capacity | *Analysis Group* curve, the intersection of the gas capacity supply and demand curves determines how much non-firm gas-only CSO [capacity supply obligation] will be awarded and how much less that CSO will be paid," Otto said.

Gas generation backed by firm fuel arrangements would earn the full capacity price paid to all other resources and would decrease the estimated amount of gas available to resources without firm contracts.

This approach differs from the marginal-reliability-impact approach ISO-NE plans to take for other resource limits.

The RTO's basic accreditation approach is intended to quantify each resource's ability to reduce the amount of expected unserved energy during forecasted periods of energy shortfall. Factors such as outage rate, intermittency or fuel storage capabilities would be reflected in the amount of capacity that resources are allowed to sell in the market.

The gas constraint would be calculated separately from the accreditation values assigned to gas resources. ISO-NE plans to use an accreditation methodology similar to that of other non-energy limited thermal resources. Accreditation values would be based largely on resources' forced outage rates and maximum capabilities, Otto said.

ISO-NE will rely on modeling by the Analysis Group to estimate how much gas is available to all resources. Todd Schatzki, principal at the Analysis Group, *presented* the firm's methodology for modeling gas availability.

The consulting firm plans to calculate total pipeline gas availability based on the 50 highest-inflow days since 2021, which marks the last time there was a significant increase in pipeline capacity into the region.

To estimate available supply from LNG terminals, Analysis Group will use an economic model that accounts for weather and temporal variables, which incorporate effects related to the day of the week and time of the year.

Schatzki noted that decisions about LNG releases are dictated by opportunity costs, because LNG terminals typically have a fixed amount of seasonal supply to sell over the course of the winter season.

"Total winter sendout from LNG terminals varies annually based largely on preseason contractual commitments and to a lesser degree in-season spot cargoes," he noted, adding that total seasonal LNG procurements affect the amount of gas available from LNG injections on a given day.

While it is difficult to predict total seasonal LNG supply, it is "important to control for annual variation in total LNG sendout," he said.

To calculate how much of the total LNG and pipeline gas supply is available to generators, Analysis Group will subtract daily non-generator gas demand. It will calculate non-generator gas demand based on a regression model that includes similar weather and temporal variables as are used for the LNG supply calculation.

For ISO-NE resource adequacy analyses, Analysis Group will account for uncertainty in its forecast of total gas supply by calculating the total amount of gas available to generators using 24 simulated load winters. For each winter, the firm will "develop 10 profiles of available gas electric supply representing distribution of uncertainty in estimated available electric supply," Schatzki said.

Also at the MC meeting, Otto presented ISO-NE's proposed accreditation framework for energy limited resources, a category that includes oil, jet fuel, kerosene and dual fuel generators.

ISO-NE would determine energy limited status for these resources "seasonally based on their usable fuel inventory levels over the last three seasons," he said, adding that resources unable to run at their maximum capability for 24 straight hours would be considered limited.

"ISO estimates suggest less than 900 MW of the region's roughly 12,000 MW of oil, jet fuel, kerosene or dual fuel resources will be considered energy limited in the winter and around 500 MW will be modeled as energy limited in the summer," he said.

The main accreditation factors for these resources would be maximum capability, forced outage rate and daily energy limit.

Fuel inventory evaluations would be based on an average of the median seasonal inventory levels over the past three years. The RTO plans to allow certain exemptions or special treatment for newly commercial resources or resources that experienced extended forced outages that affected their fuel inventory levels in past winters. ■

NEPOOL Committees Support ISO-NE Prompt Capacity Auctions

By Jon Lamson

WESTBOROUGH, Mass. — NEPOOL technical committees voted in favor of ISO-NE's proposal to adopt a prompt capacity auction and update the RTO's resource retirement process, indicating broad stakeholder support for the first phase of ISO-NE's capacity market overhaul.

In a joint meeting Nov. 12, the NEPOOL Markets Committee voted 97.9% in favor of the proposal and approved one of three amendments proposed by stakeholders. The NEPOOL Transmission Committee voted to support the associated transmission-related changes.

The proposal encompasses the first phase of work in ISO-NE's Capacity Auction Reform (CAR) project. The RTO began stakeholder discussions in September on the second phase of the project, which centers around accreditation changes and shifting to a seasonal capacity market. (See *ISO-NE Kicks off Talks on Accreditation, Seasonal Capacity Changes*.)

While ISO-NE plans to file the two phases separately, both are intended to take effect for the 2028/29 capacity commitment period (CCP).

Under the proposed changes, ISO-NE would hold capacity auctions about a month prior to the start of each CCP, compared to the more than three years that have historically separated Forward Capacity Auctions and CCPs.

The proposal would also decouple resource deactivation from the auction process. ISO-NE has said processing resource deactivations in the immediate leadup to prompt auctions would not give it enough time to address any issues triggered by retirements. In the Forward Capacity Market, resources submit delist bids more than four years before the relevant CCP.

ISO-NE proposes to require resources to submit deactivation notifications one year before the start of the relevant CCP. It has said the one-year deadline balances the tradeoffs between a longer timeline, which would give ISO-NE and market participants enough time to respond to retirements, and a shorter timeline, which would enable resources considering retirement to make a better informed decision.

What's Next

The amended proposal now heads to the NEPOOL Participants Committee for a vote in December, after which ISO-NE plans to file the changes with FERC. The RTO aims to complete the second phase of the CAR project in late 2026.

While the changes received widespread support from NEPOOL members, several stakeholders outlined lingering concerns about the risk that ISO-NE will not be able to obtain FERC approval of the second phase of CAR changes in time for the 2028/29 CCP, leaving the phase 1 changes to stand alone for the first prompt auction.

Stakeholders also expressed concern that the shorter retirement notification period will increase the risk of out-of-market resource retentions. They emphasized the need to encourage bilateral transactions to protect against price volatility.

The MC also voted 83.3% to adopt an *amendment* by the New England Power Generators Association (NEPGA) to maintain ISO-NE's current rules allowing capacity supply offers to reflect resources' physical limitations in high ambient temperatures.

ISO-NE had proposed to eliminate its option for resources to submit ambient air delist bids associated with capacity it would not be able to provide when ambient temperatures exceed 90 degrees Fahrenheit. These delist bids are not subject to cost review by the Internal Market Monitor.

NEPGA made the case that, without the amendment, market participants would "unnecessarily be required to submit a cost workbook for megawatts it is physically unable to produce at those high ambient temperatures." It proposed "technical conforming language" extending the existing exemption to the new design. ISO-NE indicated it would adopt the changes into its proposal.

The MC rejected a pair of proposals related to the competitive offer price threshold (COPT), which sets the price above which offers are subject to Monitor review.

Under ISO-NE's proposal, the RTO would continue to calculate the threshold based on the previous capacity auction clearing price and forecasting for the upcoming auction.

Several stakeholders have expressed concern that relying on four-year-old prices to set the threshold in the transition to a prompt auction could create issues related to stale data, pointing to higher prices in recent annual reconfiguration auctions and a recent increase in Pay-for-Performance penalties.

Calpine and LS Power each offered amendments to the threshold methodology. Calpine *proposed* basing the threshold on a calculation of the opportunity cost associated with scarcity revenues, while LS Power *proposed* a one-year fixed price for the 2028/29 CCP based on the outcomes of recent reconfiguration auctions.

Both proposals fell short of the 60% voting threshold for MC support. Calpine's proposal received 53.8% support, and LS Power's received 56.7%.

ISO-NE acknowledged the concerns about stale data and said it plans to take a more in-depth look at the threshold in the second phase of the CAR project.

If the second phase of CAR is not approved prior to the 2028/29 CCP, "the ISO anticipates that it would make further updates to the [phase 1] design, which would include an assessment of the COPT given the latest information available," the RTO noted in a *memo* published prior to the meeting. ■

Top Mass. House Members Seeking Major Rollback of Climate Laws

By Jon Lamson

Top Massachusetts House members are pushing an expansive energy bill that would scale back several major climate initiatives and programs and give the state immunity from legal challenges that result from missing its 2030 climate targets.

While the bill appears to have almost no chance of passing in the Senate, the legislation marks a significant change in the House's approach to climate and energy policy. The bill has drawn immediate outcry from climate and consumer advocates. And it sets the stage for a high-profile clash between environmental advocates and industry groups that historically have opposed climate policy.

"This bill is a major attack on the climate policy that we've had since 2008," Larry Chretien, executive director of the Green Energy Consumers Alliance, told *RTO Insider*.

The legislation, sponsored by Rep. Mark Cusack (D), responds to a wide-sweeping energy bill introduced by Gov. Maura Healey (D) in May. (See *Mass. Gov. Healey Introduces Energy Affordability Bill* and *Stakeholders Mixed on Massachusetts Energy Affordability Bill*.) Cusack is the top House member on the legislature's powerful Joint Committee on Telecommunications, Utilities and Energy.

While Cusack's and Healey's bills both claim to take aim at energy affordability challenges in the state, their approaches vary significantly. While Healey's bill takes a more technocratic approach to cutting energy costs and largely avoids cuts to climate and clean energy initiatives, the House bill would seek to cut costs by taking aim at a myriad of decarbonization programs and requirements.


The Massachusetts State House in Boston | *Shutterstock*

"This is a bill that saves significant money, real hard dollars, that people will see the impact of," Cusack said in a recent *interview* with *CommonWealth Beacon*. He added that the Trump administration has significantly set back the state's ability to meet its near-term climate targets and that changes to the climate targets are necessary to protect the state from lawsuits.

The bill includes several proposals favored by industry groups, including the changes to the state's decarbonization targets and regulatory changes that could make it easier to finance new pipeline projects. (See *Gas Industry Sees Political Opportunity in New England*.)

"It's a pro-utility bill, it's a pro-natural gas bill," Chretien said, adding that he was surprised by the extent of the proposed policy rollbacks. "I don't think it's a foregone conclusion that this passes the House."

Key Components

The bill's proposals include significant changes to the Mass Save energy efficiency program, which has become an important vehicle for incentivizing heating electrification in recent years.

It would reduce the budget for the 2025-27 Mass Save plan from $4.5 billion to $4.17 billion, after the Department of Public Utilities already *reduced* the proposed plan from $5 billion to $4.5 billion in February. For future three-year plans, the bill would cap Mass Save budgets at $4 billion.

The bill would allow customers to receive Mass Save rebates for gas furnaces and would undercut a demonstration project in the state that authorizes 10 municipalities to ban fossil fuels in new buildings and major renovations. Under the proposal, customers in municipalities participating in the demonstration project would be prohibited from receiving heating electrification incentives from Mass Save.

What's Next

Cusack has said he intends to seek a full House vote on the bill before formal legislative sessions end for the year on Nov. 19, setting the stage for a high-profile clash between environmental advocates and industry groups.

It also would remove the social cost of carbon from DPU and Mass Save calculations of cost effectiveness and would prohibit state entities from promulgating any regulations or programs that have "unreasonable adverse impacts" on energy costs or the "the operating costs or economic competitiveness of Massachusetts businesses."

The House proposes authorizing the state's electric utilities to enter long-term gas contracts, which could lift a major barrier to the development of new pipeline infrastructure into the region. (See *Pipeline Expansion Highlights Key Questions About Gas in New England*.)

Cusack's bill would scale back the state's Renewable Portfolio Standard (RPS), decreasing the required annual increase in the RPS from 3 to 1%. It would require the state to return to ratepayers 70% of alternative compliance payments made under the RPS.

Some aspects of the bill are aligned with clean energy priorities, including several provisions promoting surplus interconnection service and flexible interconnection. The bill would give the Department of Energy Resources increased procurement authority and set targets to procure 10,000 MW of solar and 10,000 MW of offshore wind by 2040.

Emissions Limits

Regarding the state's five-year decarbonization targets, the bill includes language intended to prohibit any legal action against the state if the state fails to meet its 2030 emissions limit.

A 2021 law set the 2030 emissions limit at 50% below 1990 emissions levels. If emissions exceed the limit, the law requires the state to "describe remedial steps that might be taken to offset the excess emissions and ensure compliance with the next upcoming limit."

While environmental advocates have strongly opposed efforts to undermine the state's climate targets, interpretations vary regarding the extent to which the state is vulnerable to lawsuits for failing to meet its emissions limits, and limited legal precedent exists on the issue.

Sen. Mike Barrett, the top senator on the joint TUE committee, has stressed that the 2030 limit is "not a rigid five-year requirement, and no one has ever pointed to legal language that suggests otherwise."

"The only hard and fast goal in Massachusetts law is net zero by 2050," Barrett said in a conversation with *RTO Insider* in October. "The language is carefully written; if we fail to meet a limit or sublimit by 2030, we're supposed to try extra hard to get us back on track by 2035 or 2040. I wrote that language, so I know what I'm talking about."

Reactions

Environmental and consumer groups panned the bill, arguing it would gut the state's climate laws while providing minimal cost benefits for ratepayers.

"This bill represents an attempt to undo decades of good climate policy in our commonwealth — policies and programs that many House members who serve with Chair Cusack spent blood, sweat and tears on," said Vick Mohanka, director of Sierra Club Massachusetts.

Caitlin Peale Sloan, the Conservation Law Foundation's vice president for Massachusetts, called the bill "nothing short of betrayal," adding that "rolling back the state's commitments to affordable, clean energy is a gift to polluters and a slap in the face to every resident who deserves better."

Kyle Murray, the Acadia Center's Massachusetts program director, said the bill fails to "meaningfully address many of the largest real underlying energy cost drivers," including gas volatility, spending on gas distribution pipe replacements, electric transmission costs and utility profits.

Meanwhile, the Associated Industries of Massachusetts (AIM), the largest business association in the state, praised the bill.

"We applaud Chair Cusack and the House for boldly protecting Massachusetts consumers by offering meaningful reforms that will generate real energy cost savings at a time when everything is expensive," said AIM CEO Brooke Thomson in a statement. "This legislation confronts the harsh realities of our climate policy decisions and ensures the commonwealth is set up for long-term success in meeting these climate goals."

Cusack did not respond to multiple requests for comment. ■

MISO States Call NERC's Planned RA Standard Inappropriate

By Amanda Durish Cook

The Organization of MISO States is warning NERC that its possible new resource adequacy standard would tread on states' planning authority.

In draft comments, OMS said NERC's potential standard positions it "for the first time beyond resource adequacy assessments, which Congress clearly mandated NERC produce, into enforceable resource adequacy standards" with corrective action plans.

NERC is developing a possible new *approach* to resource adequacy standards that may set new, actionable instructions to maintain reliability.

The organization opened a comment period through Dec. 10 on its plan, which would have planning coordinators conducting their own Long-Term Energy Reliability Assessments using an unserved energy basis and reporting the results to NERC. The plan would take a step beyond the customary one-day-in-10-years loss-of-load expectation metric.

NERC's outline calls for resource planners and transmission planners to prove they have developed corrective action plans — enforced by the ERO — to address "unacceptable" levels of reliability risks in long-term assessments.

Speaking at the OMS Board of Directors' meeting Nov. 10, Wisconsin Public Service Commissioner Marcus Hawkins told fellow regulators that states and RTOs already conduct the analyses NERC is advising and make their own resource adequacy plans.

Why This Matters

The Organization of MISO States will tell NERC to rethink its reliability standard in development. As it's written now, OMS says the plan will intrude on states' authority over resource adequacy.

The OMS Annual Meeting in session Oct. 21 in Sioux Falls, S.D. | © *RTO Insider*

'Reinforce Rather than Override'

Hawkins said NERC "does not have the authority to issue the standard in its current form." He called NERC's effort a "renamed resource adequacy standard" that usurps authority from the states and transfers it to a planning coordinator.

"The draft appears to expand NERC oversight into areas reserved for state authority under the Federal Power Act," OMS wrote in draft comments, adding that it could "shift state regulators from decision-makers to reviewers of federally enforceable actions." The group of states said NERC should stay out of policymaking and stick to reliability assessments that "reinforce rather than override" state resource planning.

"It is essential that NERC's standards not create *de facto* resource planning or procurement mandates that bypass the processes established under state and federal law," OMS said.

Hawkins said OMS' view is NERC is taking on new responsibilities that it doesn't have permission to assume.

OMS wrote that utilities would be put in the "untenable position of being subject to conflicting obligations," referring to enforcement risk at the federal level from NERC creating friction with state laws that govern least-cost planning, rate recovery and resource approvals. OMS said a utility could propose binding resource additions in a corrective action plan outside a state review process.

OMS Legal and Regulatory Director Brad Pope said that although there are varying interpretations of the draft standard, MISO states generally construe it to be "federal overreach into state jurisdiction."

"I think it's important that we come out strong in these comments," Pope said.

Hawkins put other MISO state commissioners on notice at the OMS Annual Meeting in late October that the rollout of the new NERC standard could be problematic. At the time, Hawkins said his reading is that potential "binding corrective action plans" issued by NERC would entail some level of investment to bolster resource adequacy. He said he worried about the potential jurisdictional implica-

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MISO Interconnection Queue Dips Below 175 GW

By Amanda Durish Cook

MISO's generator interconnection queue now totals 174 GW across 944 projects, a result of several developers dropping out of the line in recent months.

MISO Vice President of System Planning Aubrey Johnson told a Nov. 11 meetup of the Entergy Regional State Committee that MISO expects even more withdrawals as its planners begin processing studies. Johnson said many developers left the queue after the Trump administration announced it would abolish tax incentives for renewable energy development.

MISO's queue has dropped steadily since the news. At the beginning of 2025, MISO said it had 312 GW to study; by September, that number had fallen to 215 GW. (See *MISO Interconnection Queue Drops to 215 GW on Tax Incentive Phaseout*.)

Johnson said MISO now expects to be able to sign 25 GW of interconnection agreements annually.

"We are moving projects through the interconnection queue; we are getting projects ready to come online," Johnson said. He said MISO will work on the 2022, 2023 and 2025 cycles of projects; the RTO skipped the 2024 cycle while it designed a queue megawatt cap and put stricter rules in place to discourage developer speculation.

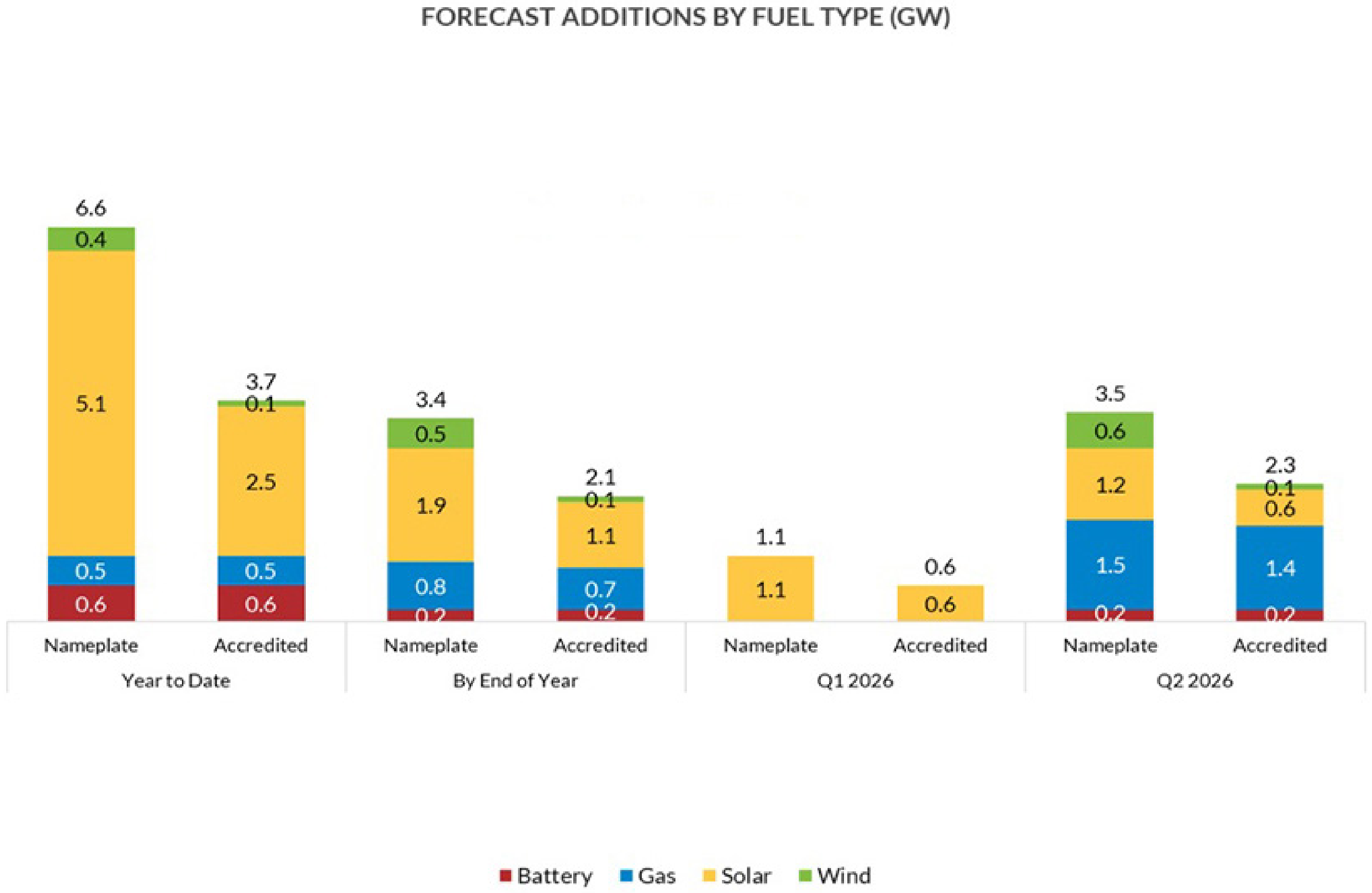
Between now and the second half of 2026, MISO estimates its members will add 8 GW of nameplate capacity (5 GW on an accredited basis) to the system.

Johnson said if achieved, those additions will exceed the 3.1 GW of capacity additions that MISO and the Organization of MISO States said were needed to meet the summer 2026 planning reserve margin. The shortfall prediction came from the MISO-OMS annual resource adequacy survey.

Johnson said as of November, MISO has 61 GW of projects with signed generator interconnection agreements that have permission to connect to the system. ■

The Bottom Line

Heading into 2025, MISO had a more than 300-GW interconnection queue. As of November, the queue has plunged to 174 GW.



MISO's forecasted capacity additions on a nameplate and capacity basis through the first half of 2026 | *MISO*

MISO Agrees with All 4 IMM State of the Market Recs

By Amanda Durish Cook

MISO said all four recommendations in the Independent Market Monitor's 2024 State of the Market Report likely are viable. The quartet of recommendations from IMM David Patton involve transmission congestion, the Midwest-South transmission link, market-to-market coordination and price settlements after grid devastation.

At a Nov. 13 Market Subcommittee meeting, Director of Market Design Zhaoxia Xie said MISO is working on the pricing recommendation and has made plans to address the other three.

Xie said MISO agrees with the Monitor that it should improve its criteria for pricing when an extreme event forces portions of the grid offline.

Patton recommended that MISO tweak portions of its "forced-off asset" declaration, namely its constraint management and dead bus criteria, to trigger the settlement style.

MISO's forced-off asset event declaration sets real-time prices equal to day-ahead prices for offline facilities. MISO created the new settlement practice in 2024 for generators physically disconnected from the grid during extensive transmission outages triggered by extreme events. It's designed to prevent generation from excessive penalties or undeserved windfalls. (See *FERC OKs MISO Settlement Rules for Widespread Tx Outages*.)

Patton said even though 2024's Hurricane Beryl forced transmission offline that disconnected most loads in the Southeast Texas Load Pocket, the storm failed to qualify as a forced-off asset event.

Patton said MISO defines its revenue inadequacy criteria too narrowly to have activated the pricing. Patton said to address the issue, MISO should add price volatility make-whole payment criteria to the revenue inadequacy criteria when making the call on forced-off asset declarations.

Xie said MISO would include price volatility make-whole payment criteria in the financial criteria for declaring a forced-off asset event. The change would require only a minor tariff edit, she said.

Squeezing More out of Midwest-South Constraint

Xie said MISO agrees it should look into more effectively using its Midwest-South transfer constraint. However, she said MISO needs to first evaluate the issue and the effects of rolling out the IMM's suggestion.

Patton proposed that MISO maximize its Midwest-to-South transmission limit by being less circumspect with the space it reserves for unforeseen flows.

MISO actively derates its Midwest-South transfer constraint to keep flows in either direction below the contractual limit. It also reserves space for unmodeled flows over the constraint that can violate the limit.

Patton said MISO's cautiousness has caused the transfer's use to be just 84% of what's contractually allowed. He said MISO should work in extra, lower-value steps to the transmission limit's demand curve and raise its energy-plus-short-term reserve limit to the highest-penalty step on the transfer to use the transmission more. Patton said a more detailed curve and relaxed limits could increase the path's use when the value of transfers is high.

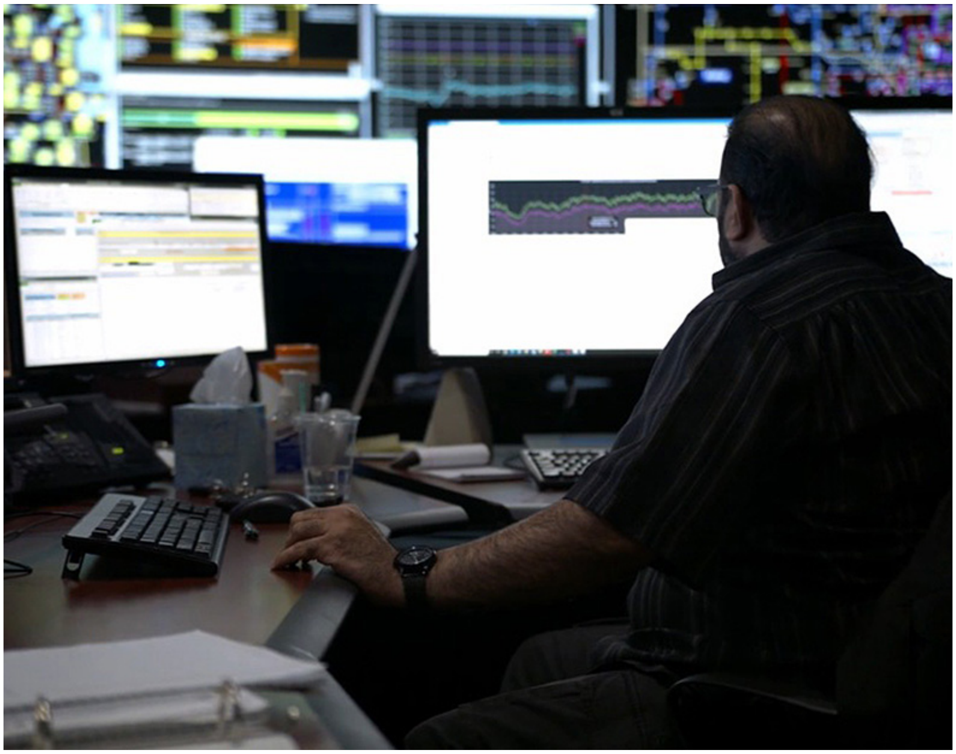
M2M Improvements

Xie said "efforts are underway" to review MISO's and its neighbors' criteria for assigning and managing market-to-market flows.

Patton advised MISO to stop accepting SPP's requests that constraints be designated for market-to-market coordination

The Bottom Line

MISO has signaled a willingness to work on issues related to transmission congestion, the Midwest-South transmission link, market-to-market coordination and price settlements after grid devastation. All four items were the source of recommendations in the IMM's annual State of the Market report.



| MISO

unless MISO is sure it can help ease the constraint.

Xie said MISO could suggest revisions or create new rules for when monitoring roles change on a flowgate or to better define effective control conditions. Xie said MISO would engage SPP especially on potential changes.

"This is a part of our continual coordination with our neighbors to manage transfers through market-to-market flowgates as well as requests for relief," Xie said.

Patton said MISO in some cases has accepted an M2M designation for flowgates from SPP even when it cannot deliver economic respite. He was among the first to alert stakeholders that MISO could offer little relief for a MISO-SPP flowgate in North Dakota strained by a new cryptocurrency mining facility. The situation in 2023 spurred complaints from the MISO side and a FERC refusal to refund about $40 million in congestion costs. (See *FERC Again Declines Changes, Refunds on Crypto-burdened MISO-SPP Flowgate*.)

Seasonal or Monthly FTR Auctions

Finally, MISO said it would consider the IMM's proposal that MISO shift most of its transmission capability to seasonal and monthly financial transmission rights auctions and auction revenue rights.

Patton has said the move would lead to more participation and liquidity in near-term auctions; reduce the risk of overselling; and improve price convergence, where FTR prices better reflect actual system conditions and values of the congestion hedges.

The IMM has said buyers often overpay for counterflow in seasonal and monthly FTR auctions with low participation, and incremental capacity is underpriced. He also has said low participation in FTR auctions by holders of ARRs suggests sluggish competition. Compounding matters, Patton said transmission owners report outages to MISO too late, which can lead to the overselling of FTRs.

"MISO agrees there's some value to moving to seasonal auctions from annual auctions and even monthly auctions," Xie said. She added that more frequent auctions would have more accurate modeling assumptions and more up-to-date outage information.

Xie said the IMM's counsel would be considered under MISO's larger work to improve its ARR/FTR Market.

MISO has become increasingly concerned over its congestion-hedging market's underfunding in recent years. It has said there's a growing discrepancy between awarded ARRs and the footprint's actual congestion patterns. As a result, load-serving entities hold a historically smaller share of FTRs, and the ARRs' congestion value has fallen. (See *MISO FTR Underfunding Hits $60M in Spring, Improvements Coming in 2025*.)

The RTO is in the exploration phase of solutions but said it wants to bolster FTR market performance and participation, improve model accuracy, ensure funding and better link the day-ahead market to the FTR market. ■

MISO States Call NERC's Planned RA Standard Inappropriate

Continued from page 33

tions of the ERO essentially mandating certain entities to open their pocketbooks to bring more resources online.

"I think that is one potential negative outcome," Hawkins said at the time.

On Nov. 10, NERC Manager of State Government and Regulatory Affairs William McCurry said the ERO recognizes that states are in charge of what is built within their borders.

McCurry also said NERC wants to engage more with stakeholders on the organization's upcoming Long-Term Reliability Assessment and would take comments on the draft report.

"We realize there were data inaccuracies with the 2024 report," McCurry told regulators and staff. "We're trying to be thoughtful and collaborative in how we approach this year's assessment."

McCurry was referencing an apparent mix-up in NERC's 2024 assessment where unforced capacity values for MISO were used when calculating a margin that NERC ultimately compared to an installed capacity requirement. (See *IMM: NERC Reliability Assessment Still Overstating MISO Risk*.) NERC fixed the mistake, and MISO was subsequently downgraded from "high risk" in the assessment to "elevated risk."

At the MISO Market Subcommittee's meeting in October, Independent Market Monitor David Patton again said the RTO is in a better place than NERC assumes in its long-term assessments, even without the errata.

"MISO was in a more reliable state than other control areas in the Eastern Interconnection," Patton said of the slew of energy emergencies that occurred June 24. He noted that PJM entered a week-long string of emergencies June 23-30.

At the OMS Annual Meeting, Bryan Clark, director of reliability analysis for the Midwest Reliability Organization, said the regional entity is working to beef up its regulatory staff to prepare for more complex assessment work. He acknowledged reliability assessments are a "projection, not a prediction" and said MRO is open to working together with MISO and its stakeholder community on reliability initiatives.

During the American Council on Renewable Energy's annual Grid Forum in late October, NERC Senior Vice President Camilo Serna said the industry needs to plan and operate the bulk power system from an energy adequacy perspective rather than a resource adequacy perspective. He said grid operators need to capture not only frequency of outage events, but also the magnitude and duration to find out what's acceptable. ■

MISO Re-examining Monthlong Outage Limit for Capacity Resources

By Amanda Durish Cook

MISO has signaled an openness to alter its 31-day planned outage rule for units that signed up to be capacity resources.

MISO said it experienced significantly more outages in summer 2025 compared to recent years, "which contributed to tight system conditions." The upsurge has MISO revisiting its generator planned outage rules.

MISO expects capacity resource owners to either procure replacement capacity or pay penalties if they are offline for more than 31 days in a season. They must notify the RTO 120 days in advance of planned outages to be exempt from capacity accreditation reductions.

Davey Lopez, manager of market design resource planning, said MISO will examine whether its outage rules are rewarding availability, as MISO intended, and determine if they need an overhaul. At a Nov. 12 Resource Adequacy Subcommittee meeting, Lopez said MISO now has three planning years of data to evaluate the impacts of its move to seasonal capacity auctions and outage rules.

The RTO's 31-day outage rule has been in effect since FERC approval in August 2022.

WEC Energy Group's Chris Plante said he believes generation owners aren't as concerned about their forced outage rates anymore under MISO's availability-based capacity accreditation. Other stakeholders agreed that unit owners are less worried about their forced outage rate and more preoccupied with being available during the predefined risky hours in a season, which MISO has placed a premium on per its availability-based accreditation.

Lopez said MISO's evaluation would look for "unintended consequences"

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and assess whether the ruleset "continues to provide the proper incentives for resources to be available during the periods of highest reliability risk and prudent planned outage scheduling." He stressed that MISO doesn't yet have any revisions in mind.

Lopez said he would appear before the RA Subcommittee in early 2026 for more discussion. ■

IMM Advises Better Constraint Management After MISO Tx Emergency

MISO's Independent Market Monitor said a MISO South September transmission emergency shows the RTO needs a better handle on constraint management within its markets.

MISO declared a local transmission emergency around 1 p.m. ET on Sept. 16 after a 500-kV transmission line was forced offline in MISO South. The IMM said the sudden outage forced two constraints into violation and congestion costs rose to $12 million.

Union Station | Entergy

"MISO was successful in avoiding a load shed," MISO Independent Market Monitor staffer Robert Sinclair said during a Nov. 11 Entergy Regional State Committee meeting. He said MISO "successfully utilized the available supply to maintain reliability through the event."

MISO confirmed that a local transmission emergency occurred in MISO South on Sept. 16.

Sinclair said MISO manually dispatched some generation to manage violated constraints and made additional resource commitments that sent some resources into their emergency ranges to increase supply by more than 700 MW.

However, Sinclair said the IMM is finding in its initial investigation that MISO should improve its transmission constraint demand curves so that the market dispatches generation instead to manage constraint violations. He said while MISO's manual dispatch actions were effective, they are more expensive than letting the market take the wheel.

Outages of 500-kV lines in MISO South "have increased in frequency in 2025 and triggered more frequent transmission emergencies," Sinclair added.

He promised a fuller report on the events and the IMM's recommended course of action at the upcoming MISO Board Week in December in Indianapolis. There, MISO leadership can respond to the recommendation. ■

— Amanda Durish Cook

MISO to Include Southeastern Texas in South Long-range Tx Planning

By Amanda Durish Cook

MISO announced it will honor a request from Texas regulators and include southeastern Texas in its first long-range transmission study for MISO South.

The grid operator earlier said it would start the process of drawing up planning studies for areas of Louisiana with heavy load pockets, marking the first long-range transmission plan for MISO South. (See *MISO Kicks off South's Long-range Tx Plan with More Restrained Approach*.) Now a portion of Texas will be part of the equation.

MISO Executive Director of Transmission Planning Laura Rauch confirmed that Texas regulators approached MISO to request that part of the state be included in the study and that MISO agreed.

Speaking at a Nov. 11 Entergy Regional State Committee meeting, Rauch told South state regulators that MISO's approach to South long-term system planning would differ from the planning conducted in MISO Midwest.

Rauch said MISO Midwest had several years of membership before MISO proposed the first, $10 billion long-range transmission portfolio in 2022 followed by the second, $22 billion portfolio in 2024.

"That journey took many, many years in the Midwest. … While I can't guarantee the outcome, I know the outcome will look very, very different in the South than in the Midwest," said Rauch, who emphasized different planning needs in MISO South.

Rauch said that over the course of 2026, MISO will assemble a study scope for

The Bottom Line

Texas regulators asked that Entergy Texas territory be included in MISO's long-range transmission planning for the South (which until now only included Louisiana). MISO agreed.

Construction on Entergy Texas' Palms Substation in 2025 | *Entergy Texas*

Louisiana and Texas, build system models and hold discussions around potential needs in the South.

"It's very likely that we'll need to do additional analysis," Rauch said. "Really, the goal is to practice the conversation around long-term needs."

Rauch said MISO "may have to divide and conquer on" which issues to tackle first and could focus first on Louisiana before turning its attention to possible projects in southeastern Texas.

"My goal is for information at this point, not necessarily a certain amount of transmission approved," Rauch said.

Arkansas Public Service Commission consultant Keith Berry asked if MISO has considered how to divide the costs of the projects.

Rauch said cost allocation negotiations "realistically" arise only when transmission needs are named. However, she said the first MISO South long-range planning — being limited to Louisiana and Texas — likely won't require the region-wide postage stamp to load cost allocation used in MISO's other long-range transmission portfolios.

"I will say with a focus on two states, I don't see a need for a multivalue project cost allocation," Rauch said.

Rauch said she doubted that "engineering studies won't show sufficient value spread" across the entire South region.

Texas utilities Commissioner Courtney Hjaltman previously said she intended to ask the MISO board to include Entergy's Texas footprint when it begins work on a long-range MISO South plan.

"My request will be to include Texas, as we obviously have load growth that we need to have included in that study," Hjaltman said at the Oct. 23 Texas Public Utility Commission meeting.

Asked by an audience member why MISO's focus is on Louisiana, she said, "They are trying to really home in on certain areas and include Louisiana, and specifically New Orleans, which obviously had a load shed event this past summer, and that might be why, but there's just no reason that Texas shouldn't be included."

At the Entergy meeting, Berry asked where MISO stands on launching a planning study aimed at increasing transfer capability between MISO South and MISO Midwest.

Rauch said at this point, MISO believes operational fixes and increased coordination on the transmission contract path are the best way forward. MISO no longer talks about a fourth long-term transmission plan portfolio, which it once said might result in an expansion of Midwest-South transmission. ■

OMS: MISO Contains Almost 17 GW of DERs

By Amanda Durish Cook

The Organization of MISO States (OMS) estimates the RTO is up to approximately 16.6 GW of distributed energy resources across its footprint, up 3 GW from 2024.

That's according to the *2025 OMS DER Survey*, released before the Nov. 10 meeting of the MISO DER Task Force.

OMS Legal and Regulatory Director Brad Pope said the annual survey recorded a "big jump" in DER deployment from 2024 to 2025. In 2024, the survey uncovered nearly 13.6 GW of DERs. For the previous three years, OMS typically has tallied an approximate 1-GW increase in DERs year over year. (See *OMS Survey: Another 1-GW Jump in DERs in MISO Footprint*.)

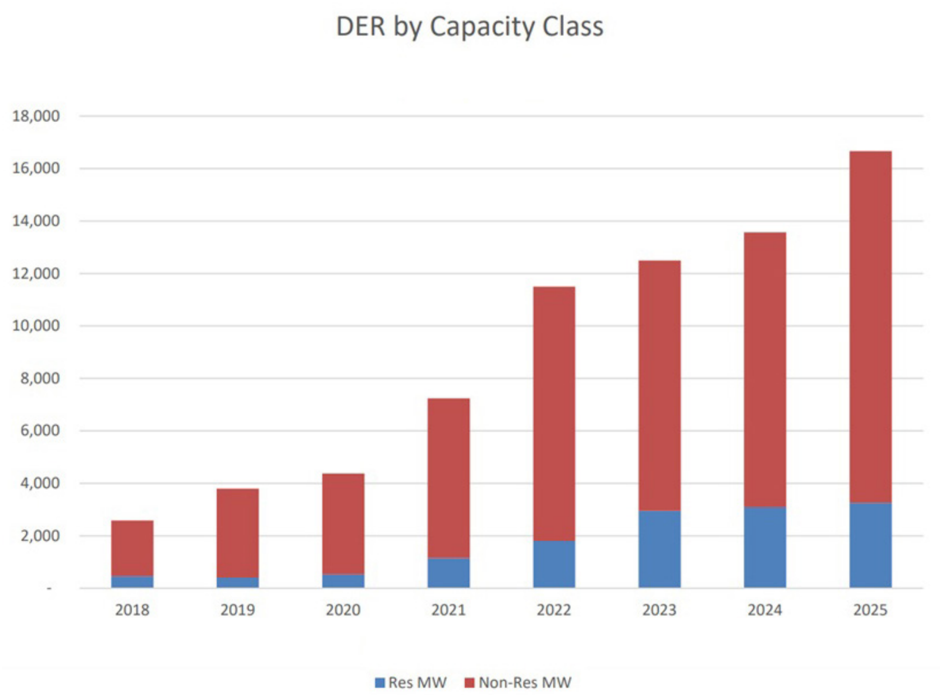
Pope said solar generation continues to dominate among reported DERs. Erik Hanser, a staffer with the Michigan Public Service Commission, said 75% of the megawatts represented in the 2025 survey originate from either solar or demand response.

Pope said some increases this year probably are due to underreporting in previous years. He said OMS is looking to improve its data collection method to get the fullest picture it can of DERs in MISO.

MISO utilities responding to the survey "still see a need for regulatory direction" on DERs, from MISO and "especially from state commissions," Pope said. He said respondents agreed that a "comprehensive and secure data registry of some form" would be useful to share DER data. Many utilities expect to encounter challenges around data sharing and secure communication when FERC Order 2222 — which will allow DER aggregators to compete in MISO's wholesale markets — takes effect in 2030.

Hanser said that in this version of the survey, OMS logged "a lot more serious talk" about DER management systems, with more utilities considering them. But Hanser said survey responses indicated DERs are still too small in size and number to materially affect the MISO transmission system or inspire planning changes. Hanser said utilities in high DER penetration areas reported a small number of backflow issues on circuits or at substations, some of which were addressed by line upgrades.

Hanser said some utilities thought MISO should lead on creating protocols to set up communication between utilities and DER aggregators. Other utilities are in the early stages of addressing communication and awaiting more information from the RTO, he said.



Growth in residential and non-residential DERs in MISO since 2018 | *OMS*

Why This Matters

For a few years, the Organization of MISO States has noted a 1-GW increase in DERs in the MISO footprint. From 2024 to 2025, OMS recorded a 3-GW jump in its annual DER survey.

"Overall, we got the sense that it's too early. … Utilities are waiting for guidance both from MISO and their state regulators," Hanser said. "Utilities are wary [of acting] before fully understanding how DERs will eventually operate in MISO. Utilities want to build systems they believe will interact easily with MISO rules."

During the OMS Annual Meeting in October, Executive Director Tricia DeBleeckere urged MISO and members to do more to prepare for the 2029 deadline for the RTO to comply with Order 2222.

For the first year of the survey's history, utilities reported electric vehicles as DERs, Pope said, with slightly more than 1 GW hailing mostly from Michigan's Zone 7. Pope said OMS is investigating how utilities quantify the resource capability of EVs and if the ones that showed up in the survey are capable of bidirectional services. Hanser said OMS must examine if the reported EVs are in fact being used as distributed resources and aiding the grid.

Overall, Zone 7 contains the most DERs, at a little more than 4 GW. The zone is home to a few large, behind-the-meter generators that put it beyond other MISO zones. Minnesota, Wisconsin and the Dakotas' Zone 1 holds the second-most DERs, at nearly 3.4 GW.

OMS gathers data on DER assets both registered and unregistered with MISO. Pope noted that the organization only collects information on DERs connected at the distribution level and therefore doesn't include all of MISO's load-modifying resources in its survey. ■

NYISO Meeting Briefs

Operating Committee

Aaron Markham, NYISO vice president of operations, presented the 2025-2026 Winter Capacity Assessment and Winter Preparedness *forecasts* to the Operating Committee on Nov. 13.

The ISO found that 29,893 MW of resources are available to meet a forecast peak demand of 24,200 MW. The peak last winter was on Jan. 22, 2025, at 23,521 MW. Under more extreme forecast conditions, capacity margins could be as tight as 993 MW, assuming only firm fuel. Roughly 2,100 MW of power is available this winter through emergency operating procedures.

Markham also presented the *Operations Report* for October. Peak load was 20,278 MW on Oct. 6 around 6 p.m. Wind set an all-time record of 2,389 MW generated on Oct. 31, while solar peaked at 4,502 MW on Oct. 1. Several transmission facilities associated with Smart Path Connect came on service incrementally throughout the month.

The committee passed a motion updating the *Reliability Analysis Data Manual* to clarify certain sections and include data requirements for recently adopted rules.

Business Issues Committee

The Business Issues Committee on Nov. 12 voted to recommend that the Management Committee approve the Winter Reliability Capacity Enhancements *tariff* revisions.

The changes would, among other things, split the capacity market into seasons with separate requirements. (See *NYISO: Winter Reliability Proposal to Increase Market Efficiency*.) The motion passed over opposition from NRG Energy and Hydro-Quebec. The New York Utility Intervention Unit, the New York Energy Research and Development Authority, and Danske Commodities abstained.

Matt Schwall of AlphaGen was elected as the committee's vice chair.

Budget & Priorities Working Group

The Budget & Priorities Working Group held a short meeting Nov. 10 to discuss the ISO's *draft corporate incentive goals* and possible *consumer impact analysis studies* for 2026.

The corporate incentive goals are structured as penalties to a pooled "incentive payout" awarded at the end of the year. The draft goals for 2026 include maintaining the continuity of the bulk power system in compliance with NERC and NYISO operating procedures; maintaining ERO and state reliability standards; the day-ahead market schedule being posted 100% of the time; and not creating market problems with material adverse impacts greater than $100 million in a calendar year.

NYISO also included a "quality goal" of posting the Gold Book by April 30, 2026, and the Reliability Needs Assessment by Dec. 31, 2026. "Strategic goals" include deploying the software required to incorporate the Champlain Hudson Power Express; updating the ISO's reliability planning process; and completing the additional system deliverability upgrade studies in time to inform interconnection customers in the transition cluster study and avoid termination of the study. ■

— Vincent Gabrielle

| *Shutterstock*

Pennsylvania Withdraws from RGGI as Part of Budget Compromise

By Devin Leith-Yessian

Pennsylvania Gov. Josh Shapiro | © *RTO Insider*

Pennsylvania has withdrawn from the Regional Greenhouse Gas Initiative as part of an overdue budget compromise signed by Gov. Josh Shapiro.

The commonwealth's participation in the initiative never was established fully, as legal issues delayed implementation. Previous Gov. Tom Wolf signed an executive order putting Pennsylvania on a path to joining RGGI. But the plans were stymied by a lawsuit arguing that legislative approval would be required.

Commonwealth Court Judge Michael Wojcik issued an injunction in 2022, and the case remains before the Supreme Court of Pennsylvania. (See *Court Blocks Pennsylvania from Joining RGGI*.)

House Minority Leader Jesse Topper (R) criticized RGGI as the most significant issue holding back economic growth.

"Being a part of the Regional Greenhouse Gas Initiative is truly what was keeping energy development out of Pennsylvania, as we were losing jobs to West Virginia and Ohio," he said in floor comments Nov. 12. "After today, that specter will be gone, and I believe this is a moment we can look to in time that we will say Pennsylvania started to meet its full potential when it came to developing energy."

Rep. Greg Vitali (D) voted against the budget compromise because of the RGGI rider, saying climate change is one of the most significant long-term threats to the planet. Given the divided legislature, he said climate change bills have little chance of passing.

"RGGI is a tried-and-true program, it is market-based, it has been in effect since 2009. … Since that time, there has been a 46% decline in carbon emissions from the power facilities in those (participating) states and there has been a $9 million investment in clean energy projects for those states," he said, citing statistics from RGGI. "It's very disappointing that our governor does not support RGGI, and that is why it is on the chopping block today."

Environmental groups criticized the agreement. PennFuture called it a "stunning betrayal" of the environment and an initiative that could have brought hundreds of millions of dollars to the state to lower energy bills and promote clean energy.

"Pennsylvania was on the goal line of making meaningful progress toward cleaner air, lower energy costs and reduced pollution," PennFuture CEO Patrick McDonnell said in a *statement*. "Instead of finishing the drive, the governor and house Democrats didn't just fumble the ball, they picked it up and ran it into the opponents' end zone."

NRDC Policy Director for Pennsylvania Robert Routh said the state's participation would have been significant given the scale of its carbon dioxide emissions, which amount to roughly all of the other states participating in RGGI combined. He cited EPA figures finding Pennsylvania fossil fuel generation released just under 78 million tons of carbon dioxide in 2024.

Shapiro proposed an alternative cap-and-trade market limited to the state as part of his Pennsylvania Climate Emissions Reduction Act (PACER) bill. It failed to advance in the 2024 legislative session and was reintroduced in 2025. Given how heavily the language leans on the framework the Pennsylvania Public Utility Commission established for participating in RGGI, Routh said PACER likely would need rewriting to be implemented on its own.

If the state had a binding carbon cap-and-trade price on emissions from power plants, Routh said it would have enabled historic investment opportunities to strengthen local economies and battle climate change effects. He estimated the auction for the third quarter of 2025 would have created as much as $300 million in revenue for the state. The impact could have been even more significant, as data center load growth is

Why This Matters

High capacity prices in PJM could spur development in Pennsylvania regardless of its participation in RGGI. One of the biggest barriers for renewables is the amount of time it takes to get through the interconnection process.

expected to accelerate.

"RGGI would have been an incredibly effective tool at both keeping pollution and cost down in the face of anticipated large load growth," he said.

Advanced Energy United Director of Wholesale Markets Jon Gordon said high capacity prices in PJM likely will spur development in Pennsylvania regardless of its participation in RGGI. The largest barrier for renewables is the amount of time it takes to get through the RTO's interconnection process.

"As a practical matter, Pennsylvania participation in RGGI has been tied up in court for years, so this shouldn't have a meaningful impact on project development, particularly given PJM's high capacity prices, which reflect a significant supply shortfall relative to surging demand for energy," he told *RTO Insider.* "With the 'Lightning Plan,' Gov. Shapiro has proposed legislation that would help get these projects built faster by speeding deployment and reducing barriers to clean energy investment. Pennsylvania should seize that opportunity."

Virginia's beleaguered participation in RGGI is a mirror image of Pennsylvania's. It joined the initiative legislatively in 2020 and participated in auctions until 2023, when Gov. Glenn Youngkin (R) sought to withdraw through executive order. In November 2024, a judge found Youngkin's action unlawful, stating that the authority to withdraw was held by lawmakers. That ruling was frozen temporarily in March 2025 when the administration appealed.

Compromise Includes Review of Utility Load Forecasting

The Pennsylvania budget *legislation* includes a section granting the Public Utility Commission "the ability to investigate methodologies, data and assumptions used by utilities when developing load forecasts submitted to PJM."

PJM has encouraged state regulators to take a more proactive role in reviewing utilities' load forecasts, particularly large load adjustments (LLAs), which often include data center projects not captured in the standard economic modeling. PJM's Critical Issue Fast Path proposal, one of a dozen to be voted on Nov. 19, would add a review to its load forecast process for state commissions to review LLAs.

Routh said there has been a sharp increase in efforts to address the effect large load growth is having on constituents' bills, with the accuracy of forecasts central to ensuring consumers don't pay for transmission and capacity that will go unused. He said the language on reviewing utility forecasts rapidly moved from legislative committees into the budget legislation. ■

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Nov. 20. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

As part of its consent agenda, the committee will be asked to:

B. endorse proposed *revisions* to Manual 3: Transmission Operations drafted through the document's periodic review. The changes aim to clarify the load drop rating requirement for Bulk Electric System facilities.

C. endorse proposed *revisions* to Manual 39: Nuclear Plant Interface Coordination proposed as part of the document's periodic review. The language seeks to align with NERC's NUC-001: Nuclear Plant Interface Coordination standard.

D. endorse and approve *revisions* to PJM's tariff, Reliability Assurance Agreement and Operating Agreement as proposed by the Governing Document Enhancement & Clarification Subcommittee. The changes reflect those to the tariff approved by FERC and remove outdated language. (See "1st Read on GDECS Tariff Revisions," *PJM MRC/MC Briefs: Oct. 23, 2025*.)

Endorsements (9:10-9:40)

1. Load Management and PRD Event Performance (9:10-9:40)

PJM's Pete Langbein will present a *problem statement* and *issue charge* for stakeholders to consider how load management and price-responsive demand performance can be improved.

Members Committee

Consent Agenda (11:05-11:10)

As part of its consent agenda, the committee will be asked to:

B. endorse proposed tariff and OA revisions to revise how wind and solar resources are dispatched in the real-time market clearing engines. (See "Renewable Dispatch Proposal Endorsed," *PJM MRC/MC Briefs: Oct. 23, 2025*.)

Issue Tracking: *Wind and Solar Resource Dispatch in Real-time Market Clearing Engines* ■

— Devin Leith-Yessian

PJM Stakeholders to Vote on Large Load CIFP Proposals

By Devin Leith-Yessian

PJM stakeholders are to vote on a record-breaking number of proposals on how the RTO should integrate large loads without impacting resource adequacy. (See *PJM Stakeholders Present CIFP Options for Meeting Rising Data Center Load*.)

A dozen packages of changes are to be voted on at a special Members Committee meeting Nov. 19, which will immediately follow the Critical Issue Fast Path (CIFP) stage 4 meeting, in which sponsors will present to the PJM Board of Managers. The voting will be advisory to the board, which outlined its intent to direct PJM to make a December filing on a path forward for large loads in its *letter* initiating the CIFP process. The stage 4 meeting is closed to the media.

The bulk of the packages mix and match elements of several design components that have been developed across 10 meetings held since August.

Bring-your-own-generation or capacity (BYOG or BYOC) would incentivize, or require, new large loads to have resources to serve themselves. This could take the form of expedited interconnection, penalties for large loads that don't self-supply or prohibiting interconnection. Proposals differ on whether the resource can be existing or must be new, as well as whether it must be adjacent to the load.

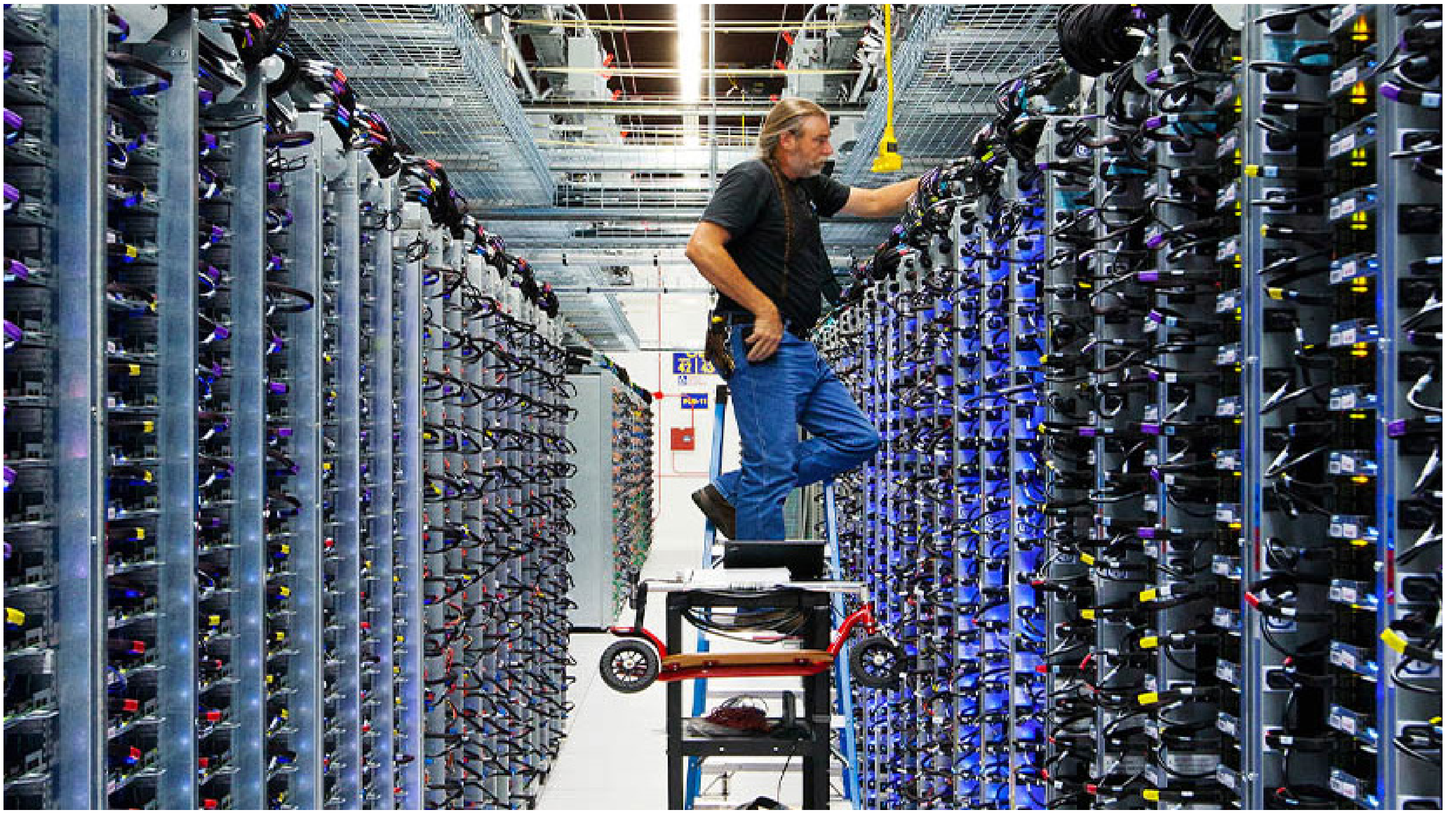
Instituting queues for large loads also features prominently in some proposals, requiring them to hold off on interconnection until there is sufficient capacity to serve them or they procure their own capacity. Opponents have argued these models could impinge on state jurisdiction over retail interconnection.

Load flexibility would allow large loads that agree to curtail similar to demand response to either qualify for expedited interconnection or subject them to mandatory curtailment under new emergency procedures if they do not bring their own generation. Some proposals include limited-duration products with a maximum number of hours a customer could be dispatched during one event and across a delivery year. In the *executive summary* of its proposal, PJM said limited-duration DR would not be implementable until the 2029/30 Base Residual Auction (BRA).

PJM's original CIFP proposal featured a mandatory non-capacity backed load (NCBL) model in which large loads would not pay for or receive firm service unless they brought their own generation; the RTO has dropped that concept, but versions have been adopted in alternative packages.

Bifurcating the capacity market would add a second phase to auctions where large loads would clear after all other RTO loads, potentially receiving a higher clearing price. They differ on whether the resources participating in the second phase would be limited to new resources or could include existing assets. ■

This article has been edited for length. Click here for the full version.



A technician works at a Google data center. | *Google*

Markets+ Cruising Through Early Development

SPP Says Protocols, Timeline, Budget, Staffing on Schedule

By Tom Kleckner

TEMPE, Ariz. — This is the easy part, says Scott Miller, executive director of the Western Interconnection's competitive market advocate, Western Power Trading Forum.

Indeed. Members of SPP's Markets+ Participant Executive Committee unanimously endorsed every proposed tariff and protocol revision, with the occasional abstention here or there, during their Nov. 13 meeting. They agreed — again, unanimously — to retain the stakeholder group's leadership for additional two-year terms during the day-ahead market's implementation phase.

Nary was a discouraging word heard.

"We're getting to the nub of things, but people are understanding them and digesting them," Miller told *RTO Insider* after the meeting. "They're getting used to the process, and this is obviously a lot of detail that people were dealing with. It still is a collegial group. It's come a long way since it first started two years ago."

Miller has seen these conversations and debates before. He said he saw firsthand the difficulties CAISO ran into as it drafted and filed its implementation tariff for its Extended Day-Ahead Market.

"There will obviously be harder issues as they get closer to the go-live date," he said. "When you start getting into implementing tariffs and things like that, that's where difficulties and disagreements and things pop up that people didn't realize were there. I think we'll find some things that will surprise us when the implementation tariffs for Markets+ get filed."

Miller speaks from experience: He helped lead PJM's market development in the early 2000s and later spent nine years at FERC advising commissioners and staff on electric and natural gas markets.

He said he's not concerned about Markets+' sometimes-languid pace of development. With a targeted go-live date of Oct. 1, 2027, SPP is already 18 months behind CAISO's EDAM. That market is to go live in May 2026 for PacifiCorp and Portland General Electric, with others following in later months.

"It's a considered pace," Miller said, noting that Western entities have never dealt with tariffs and organized markets until recently.

"The differences between market participants will begin to show themselves once you get into actual market operations, but for now, everybody's pulling on the same oar," he said. "People are taking things very seriously. Protocols associated with tariffs require a lot of attention."

One complication is that SPP and CAISO are both relying on the West's 37 existing balancing authorities, rather than a consolidating BA as grid operators normally do. Transmission operations will remain with their control areas, and SPP will clear units, but the BAs will still be responsible for dispatch.

"For reasons that still escape me, you're taking a step toward something like an RTO but making it very complex by the fact that you maintain balancing areas and tariffs that don't exist in RTOs," Miller said. "It's a step toward an RTO, but it's much more complex than an RTO."

MPEC members were unable to agree on whether to hire an external market design adviser and tabled the issue a second time. It will remain tabled until "interested parties" submit a proposal with specific issues for the committee's consideration.

An SPP survey of MPEC's 41 members found only minimal support, 17-16, to engage an external consultant or adviser during the market implementation's early stages, given its "new design approach." Those voting against the proposal said they saw little benefit for the expense.


Tim Vigil, Markets+ MMU | © *RTO Insider LLC*

Western Resource Advocates (WRA) proposed the position in 2023, and SPP began working on a plan and structure for the adviser in early 2024 before it was tabled the first time later that year. Staff have suggested the position report to SPP.

> **Why This Matters**
>
> SPP says everything is progressing smoothly as stakeholders begin design Markets+'s day-ahead design. Things are expected to get a little dicier when participants begin digging into the protocols' details.

WRA saw the position as possibly filling a market monitoring role, but SPP in September brought on Tim Vigil to lead the 16-person Markets+ Market Monitoring Unit that will identify market design flaws and ensure compliance with market rules. Vigil was previously chief member relations and strategy officer for the Pacific Northwest Generating Cooperative and also spent time with the Western Area Power Administration. (See *SPP Names Director to Lead Markets+ Monitoring*.)

Vigil stressed the MMU's independence in introducing himself to the MPEC.

"The independence allows us to be objective [and] impartial while we're monitoring the market, investigating potential problems and protecting the market to ensure workable competition," he said. "It just puts us in a place to accomplish these things without any undue influence.

"The MMU is committed to be transparent … with FERC, SPP and all the stakeholders that are sitting here today," Vigil added. "Our obligation is to inform FERC of any proposed tariff changes with something that we identify that we'd like to see. We're not trying to surprise anybody."

The Markets+ MMU will be separate from the SPP MMU. The Western monitor will increase the MMU's total staff from 23 to 38.

Readiness Activities Progressing

Kevin Morelock, an SPP Markets+


Western Power Trading Forum's Scott Miller (left) and Western Freedom's Andrew Sand confer during the November MPEC meeting. | © *RTO Insider*

program manager, said stakeholders' decision to run the market in the Pacific Time Zone has created issues as the grid operator tries to save on infrastructure costs.

The RTO's Integrated Marketplace in the Eastern Interconnection uses the Central Time Zone for its operating day procedures.

"It's causing some complexity with our design and being able to operate both in a CT time zone for the RTO and Integrated Marketplace and then PT for Markets+," he said, citing the challenge of modeling both markets at the same time and the boundaries between monthly releases.

Still, Morelock said the program implementation's design phase is on track. Staff have refined the timeline, work plan and operating time zone effects to downstream SPP systems, and an internal strike team has been assembled to mitigate issues and risks.

Chief among the risks are staffing and registration delays, Morelock said. The grid operator had hired 42 of 47 full-time-equivalent employees through September. It expects hiring to pick up in January and eventually reach a target of 206 FTEs in June 2027.

The RTO has completed 52 of 60 market registrations for BAs and non-BA transmission providers. Entities desiring to register as market participants face a Dec. 1 deadline, but Morelock said staff may adjust the schedule to ensure it doesn't miss embedded entities or transmission customers of the BAs or transmission providers.

"We're really continuing to ask MPs to come forward and declare their interest in joining Markets+ for those entities that are transmission customers or embedded entities," he told MPEC.

The program is operating under its budget through September, Morelock said, and is on pace to meet its forecast $149.7 million total. That includes almost $10 million in financing charges.

The Markets+ Design Working Group is leading a holistic review of the protocols — including checking for alignment with the Markets+ tariff, improving readability and adding late changes — working with stakeholders first. The group plans to bring the finished product to a Dec. 18 MPEC conference call for its approval.

MSC to Gear up Involvement

Idaho Public Utilities Commissioner John R. Hammond Jr. stood in for Arizona Corporation Commission Vice Chair Nick Myers, chair of the Markets+ State Committee, and told MPEC members that state commissioners will participate in and monitor the stakeholder groups as the market's development phase moves forward.

Much of the MSC's focus will be on the tariff's development, implementation effort, revision request process, seams issues and interchange transactions, he said.

Hammond, the MSC's vice chair, said the increasing load growth across all states has been "truly amazing."

"There are commonalities between all the jurisdictions, and there are differences," he said. "Working together, we can really make a big difference for this country."

The Western Interstate Energy Board's (WIEB) staff, which provide independent staffing for the MSC and offer analysis on the market's development and operations, told MPEC the committee's 2026 budget will increase when it aligns with the standard fiscal cycle.

Lisa Brohaugh, WIEB's director of finance and administration, said the MSC's budget will grow to $437,923, up 12.4% from the 2025 budget of $389,680, which covered just nine months. Brohaugh noted that the previous budget of contractual expenses covered the last nine months of 2025.

The Interim Markets+ Independent Panel, composed of three SPP independent directors, will consider the budget when it next meets. SPP will then allocate the budget's costs to Markets+ participants.

Trolese, Walter to Again Lead MPEC

MPEC members accepted staff's nominations of The Energy Agency's Laura Trolese and Arizona Public Service's Kent Walter to serve additional two-year terms as the committee's chair and vice chair, respectively.

"Their leadership has been excellent so far," SPP's Kelli Schermerhorn said.

The MPEC will also retain the leadership of its four key working groups after the incumbent chairs were all nominated for additional terms: Nick Detmer (Markets+ Design WG) and Joe Taylor (Markets+ Transmission WG), both with Xcel Energy subsidiary Public Service Company of Colorado; Tuuli Hakala (Markets+ Seam WG), Chelan County Public Utility District; and Libby Kirby (Markets+ Operations & Reliability WG), Bonneville Power Administration.

MPEC's approval of the consent agenda added Chelan PUD's Peter Graf to a vacant public power seat on the MORWG; Tri-State Generation and Transmission Association's Kyle Cunningham to an open public power seat on the MSWG; and Black Hills Energy's Raena Orr to an available investor-owned utility seat on the MDWG.

The consent agenda also included a scope change for the MORWG, clarifying its responsibility to provide guidance on reliability functions and not just balancing authorities.

SPP Schedules Seams Symposium

SPP has scheduled a Western Seams Symposium for Feb. 26 that follows the MPEC's next in-person meeting.

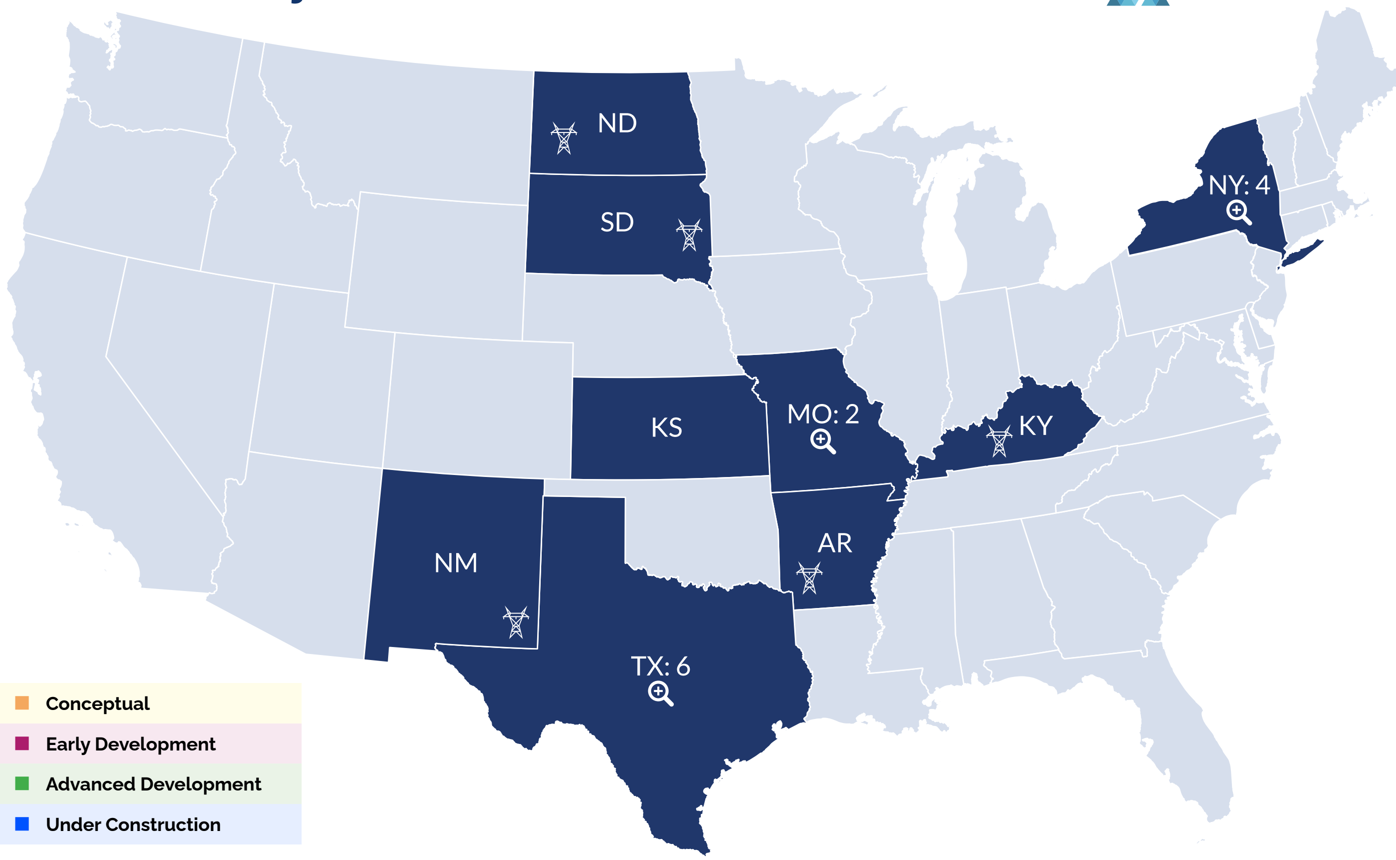
The final details are still being worked out, but staff have invited representatives from other grid operators as part of a broader regional discussion of the boundaries between entities.

SPP has touted its seams management experience with its MISO and ERCOT neighbors as preparing it for Western operations, where the markets have been placed on top of the seams between BAs and transmission providers. (See *SPP's Experience with Seams Could Help Markets+*.)

The symposium will be held at the Salt River Project's PERA Training & Conference Center in Tempe. In-person registration closes Feb. 19. ■

New T&D Projects Added in the Past Week

YES ENERGY



Conceptual
Early Development
Advanced Development
Under Construction

New Line | New Substation | New Line / New Substation | Line Upgrade | Substation Upgrade

Data from Yes Energy

	Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	State 1 / 2
	Emmet - Hope North 115 kV New Line	American Electric Power	Southwestern Electric Power Co.	115	2030	AR
	Cooper - Alcalde New Line	East KY Power Corporation	East KY Power Corporation	161	2027	KY
	Crosstown - Blue Valley Station 161 kV New Line	Evergy	Evergy Kansas	161	2029	MO - KS
	Clinton - Stilwell 345 kV New Line	TBD	TBD	345	2032	MO - KS
	Belfield - Roundup 345 kV New Line	WAPA	Upper Great Plains	345	2034	ND
	Wolfcamp Tap - Battle Axe - Ponderosa - Dollarhide 115 kV New Line	Xcel Energy	Southwestern Public Service	115	2029	NM
	Worcester - East Worcester Line Upgrade	National Grid	Niagara Mohawk	35	2029	NY
	Truxton - McGraw New Line	National Grid	Niagara Mohawk	5	2029	NY
	College Avenue New Substation and Line	National Grid	Niagara Mohawk	115	2030	NY
	Van Hoesen Greenfield New Substation	National Grid	Niagara Mohawk	69	2030	NY
	Aurora 115 kV New Lines (White)	TBD	TBD	115	2030	SD
	Adora - Pilgrims Pride 69 kV New Line	American Electric Power	Southwestern Electric Power Co.	69	2026	TX
	Center - Center South 138 kV Line Tap	East Texas Electric Cooperative	East Texas Electric Cooperative	138	2028	TX
	Buford - DeKalb 69 kV Line Tap	East Texas Electric Cooperative	East Texas Electric Cooperative	69	2031	TX
	Baldwin - Baldwin 69 kV New Line (Cross Roads - Leigh)	East Texas Electric Cooperative	East Texas Electric Cooperative	69	2031	TX
	Darco - Nesbitt - Lake O The Pines 138 kV Line Project	Northeast Texas Electric Coop	Northeast Texas Electric Coop	138	2031	TX
	Camp County POD - Ebenezer - Pittsburg - Gilmer 138 kV New Line	American Electric Power	Southwestern Electric Power Co.	138	2036	TX

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Company Briefs

First Solar Picks South Carolina for $330M Factory

First Solar has picked Cherokee County, South Carolina, for its new $330 million production facility.

The facility will onshore the final production processes for Series 6 modules initiated by the company's international fleet.

Operations are expected to begin in the second half of 2026.

More: *WYFF*

Enlight Secures $1.44B for Hybrid PV Plant

IPP Enlight Renewable Energy last week announced it has secured $1.44 billion in debt financing for its Snowflake A solar-plus-storage project in Arizona.

The project will combine 600 MW of solar with 1,900 MW of storage capacity. It is expected to become commercially operational by the second half of 2027.

Enlight has obtained commitments from a group of six major international banks, including Wells Fargo Bank, BNP Paribas, Natixis Corporate and Investment Banking, Nord/LB, Crédit Agricole Corporate and Investment Bank, and MUFG Bank.

More: *Energy Storage News*

Plug Power Puts Hydrogen Factory Builds on Hold

Plug Power last week announced it has put its plans to build up to six new hydrogen production plants across the U.S. on hold despite receiving $1.66 billion in federal loan guarantees from the Department of Energy.

The company announced it lost $120 million in the third quarter on $170 million in revenue. It said it has now suspended plans to roll out new hydrogen factories in Texas, New York and other states and will instead buy hydrogen from an existing supplier.

Plug Power makes hydrogen-powered fuel cells that generate electricity through a chemical reaction.

More: *Times Union*

Federal Briefs

Business Groups Asks SCOTUS to Pause Calif. GHG Reporting

The Chamber of Commerce last week asked the Supreme Court to pause new California laws expected to require companies to report emissions and climate-risk information.

Lower courts have so far refused to block the laws, which the state says will increase transparency and encourage companies to assess how they can cut their emissions. The Chamber of Commerce has asked the court to put the laws on hold while lawsuits continue to play out.

The measures were signed by Gov. Gavin Newsom in 2023, and reporting requirements are expected to start early next year.

More: *The Associated Press*

TVA Plans 1st Major Battery Storage Addition

The Tennessee Valley Authority last week announced it plans to add 1.5 GW of battery storage by the end of 2029.

TVA considered as much as 5 GW of storage in its last long-term plan in 2019 but added just 370 MW between 2019 and 2025.

More: *WPLN*

Latest U.N. Analysis Shows Pledges Cutting Emissions by 12%

The annual amount of greenhouse gases added to the atmosphere will decrease 12% by 2035 from 2019 levels, according to an analysis by the U.N. climate change secretariat.

The revised figure represents progress from the expected 10% reduction announced Oct. 28 and considers pledges made since the cutoff for the previous analysis. However, the projection is far short of the 60% drop needed by 2035 to limit global warming to 1.5 degrees Celsius.

More: *Reuters*

State Briefs

COLORADO

PUC Sets New GHG Emissions Requirements

The Public Utilities Commission last week agreed to tougher standards on greenhouse gas emissions from utilities and will require them to reduce emissions by 41% by 2035.

In 2021, the state passed the first-in-the-nation "Clean Heat Law," requiring gas utilities to create plans to reduce greenhouse emissions. The first target was 4% by 2025, then 22% by 2030.

The PUC is expected to formally announce the reduction requirement next month.

More: *KMGH*

INDIANA

9 Finalists Named for URC

State officials last week named nine finalists for three open seats on the Utility Regulatory Commission.

The finalists are Nathan Cazee, Christopher Lewis, Anthony Swinger, Joshua Bain, Sen. Andy Zay, Alfonso Vidal, Bob Deig, Carolene Mays and Elizabeth Walker. They were selected from a pool of 47 applicants by the Utility Regulatory Nominating Committee.

The recommendations now go to Gov. Mike Braun, who will decide which candidates to appoint.

More: *Indiana Capital Chronicle*

MISSOURI

PSC Approves Evergy's Utility Data Center Rates

The Public Service Commission last week approved a large load rate submitted by Evergy.

Large load users were defined in the order as requiring 75 MW/month at peak times.

Public Service Commission staff and the Office of Public Counsel did not support the order.

More: *The Kansas Reflector*

NEBRASKA

NPPD to File for Nuclear Plant Extension

The Nebraska Public Power District last week announced it is planning to file for a 30-year extension with the Nuclear Regulatory Commission for its 835-MW Cooper Nuclear Station.

The NRC approval would extend the station's operating life to 2054.

The company has also begun searching for a new nuclear site. A siting study narrowed the pool down to 16 locations.

More: *KETV*

NEW JERSEY

Leading Light Out on Massive OSW Project

Legal counsel for the Leading Light Wind offshore project filed a letter with the Board of Public Utilities, saying it no longer sees a way to complete construction and wants to abandon the planned 2.4-GW wind farm.

Its OREC certificate came with state financial assistance but also required developers Invenergy and energyRe to meet specific project milestones. In addition to facing supply chain issues, both companies had been unable to pursue federal permitting due to the Trump administration's policy on offshore wind. For months, they had submitted extension after extension to filing a motion binding them legally to complete construction of the project.

"The company regrets this decision but does not see a pathway forward for the LLW project on this OREC award and looks forward to the future for possible solicitations," counsel Colleen Foley said.

More: *Heatmap*

NEW YORK

Bitcoin Mine Agrees to Slash Emissions, Will Get Air Permit

A Bitcoin mining operation run by Greenidge Generation will be allowed to continue operating in the Finger Lakes under a new agreement requiring it to reduce emissions.

The new deal between Greenidge and the Department of Environmental Conservation requires the 107-MW gas plant used to run the operation to reduce its pollution by 44%, or 282,000 tons of carbon dioxide by 2030. The agreement does not offer specifics on how the company will reduce emissions. The facility releases more than 500,000 metric tons of greenhouse gases annually.

More: *Gothamist*

OHIO

Report: FirstEnergy Made $108M Expense Error

According to a new report by the Energy & Policy Institute, FirstEnergy improperly claimed $108 million in construction expenses and is now asking the Public Utilities Commission for permission to charge its customers for them.

The report found the company classified lobbying and donations as construction expenses while it also funded an infamous bribery scandal, although it's not clear if any money was paid in bribes. A 2022 audit by FERC found that from 2015 to 2021, FirstEnergy incorrectly classified millions spent on things like lobbying, advertising and political donations as construction costs. That's important, the report said, because utilities are allowed to collect a profit from ratepayers on construction investments and not allowed to collect such profits for money spent on lobbying and political donations.

The $108 million is part of a request to pass on $190 million in additional costs to ratepayers. If the PUC declines, the company would have to bill shareholders.

More: *Ohio Capital Journal*

OREGON

PUC Upholds Tx Line Approval

The Public Utility Commission last week reaffirmed its approval of a 300-mile transmission line that's set to run from Idaho and carry power across five counties despite concerns it will primarily serve a private data center rather than the public.

The commission declined to rescind a

certificate that authorizes line co-owner Idaho Power to seize private land via eminent domain and maintained the line remains in the public interest. An attorney told the PUC the utility has obtained 95% of the access rights to begin construction.

The line, now under construction after 20 years of reviews and lawsuits, will be among the largest and one of the few transmission projects built in the Pacific Northwest.

More: *The Oregonian*

VIRGINIA

Dominion Seeks Approval of 11 Solar, Battery Projects

Dominion Energy is seeking approval for 11 solar and battery projects as part of its race to meet the state's Clean Economy Act.

The projects would cost $2.9 billion and include six utility-scale solar farms, three distributed solar sites and two battery storage facilities. All are planned to come online by the end of this decade. The projects are part of Dominion's latest annual clean energy filing, which updates regulators on how they're going to meet mandates.

The State Corporation Commission will provide the final approval.

More: *WHRO*

James City County Adopts Data Center Policy

James City County last week approved new standards for reviewing data center applications.

Under the new policy, any data center should be at least 1,000 feet from residences and 250 feet from historic, recreational and environmentally sensitive areas. It also recommends that buildings meet the county's design standards, that they don't exceed 80,000 square feet and that they employ visual and vegetative buffers near property lines.

The policy includes several provisions on water and energy consumption. Data centers would be discouraged from connecting to public water systems or using well water for cooling a center's systems.

More: *WHRO*

WISCONSIN

DTE to Close Coal Terminal

Midwest Energy Resources Company, a subsidiary of DTE Electric, last week announced it will close a coal terminal in Superior.

The company said it will not renew its 50-year lease with Koch Industries as of June 30 next year. Coal tonnage has dropped 75% from its peak at the terminal due to the shift away from coal-fired plants.

More: *Wisconsin Public Radio*

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