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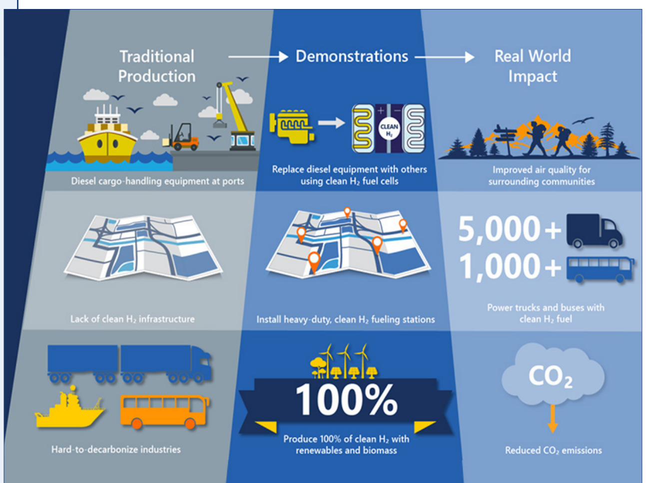
FERC/FEDERAL

DOE Terminates $7.56B in Energy Grants for Projects in Blue States



DOE

The move simultaneously targets clean energy and Democrats, both frequent targets of President Trump's ire.

CONTINUED ON P.3

COMPANY NEWS

The Boldt Co.

Minnesota PUC Approves BlackRock's Purchase of Allete (p.46)

All five Minnesota regulators said they were initially uneasy with two private equity firms taking Allete private; however, they said late-stage ratepayer protections convinced them to approve the sale.

ERCOT

AdminMonitor

Texas PUC Approves Permian, Outside ERCOT Transmission Projects (p.22)

The approved transmission projects are meant to harden the grids and improve reliability in areas of West Texas and MISO that are seeing exponential load growth.

ONTARIO ENERGY CONFERENCE

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IESO Seeking to Stay 'Two Steps Ahead' of Need (p.25)

IESO is embarking on its largest transmission expansion in two decades.

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In this week's issue

DOE Terminates $7.56B in Energy Grants for Projects in Blue States

West Coast Hydrogen Hubs, MISO-SPP Transmission Portfolio Among the Targets

By John Cropley and Tom Kleckner

The U.S. Department of Energy has terminated 321 grants totaling $7.56 billion for 223 projects, apparently targeting Democratic-leaning states.

The *Oct. 2 DOE announcement* did not specify the grants being eliminated, but later in the day, Democrats on the House Appropriations Committee *posted the list*. They said the projects are in 108 congressional districts represented by Democrats and 28 represented by Republicans.

Russell Vought, director of the Office of Management and Budget, *posted on X* on Oct. 1 that the cuts were being made to "Green New Scam funding" for projects that are part of the "Left's climate agenda." The 16 states he identified were won by former Vice President Kamala Harris in her losing run against President Donald Trump in 2024.

The 32 U.S. senators representing those 16 states are all Democrats and all voted against a bill that would have averted the federal government shutdown.

But the grant cancellations will have some fallout in red states as well.

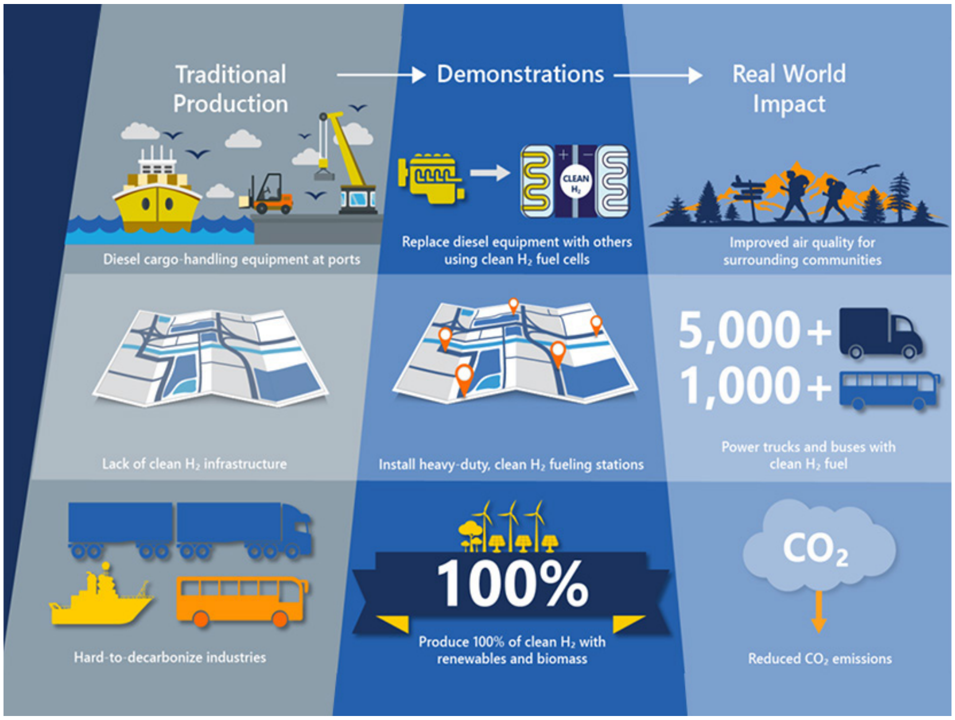
MISO-SPP Portfolio

Among the terminated financial awards, the fifth largest is the $464 million grant for the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) portfolio under DOE's Grid Resilience and Innovation Partnerships (GRIP) program.

The grant was intended to offset about 25% of the projected $1.6 billion capital costs for the JTIQ portfolio's five 345-kV projects. The funds were *awarded in 2023* to the Minnesota Department of Commerce, the lead applicant in a project that also involves the Great Plains Institute and the two RTOs. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

Why This Matters

The move simultaneously targets clean energy and Democrats, both frequent targets of President Trump's ire.



The U.S. Department of Energy is rescinding its $1.2 billion investment in ARCHES, the California Hydrogen Hub. | *DOE*

A Commerce Department spokesperson said the department has not received "any formal notification" from DOE on the GRIP funding's termination. However, it was included in the list distributed by House Democrats.

In a statement provided to *RTO Insider*, the Commerce Department said it was "deeply concerned" about DOE's suggestion of an "illegal effort to rescind federally obligated energy funds targeted exclusively at blue states."

"If true, this would represent an unprecedented and politically motivated breach of federal law and funding norms — with potentially serious consequences for families, businesses and communities across Minnesota," it said. "Without these investments, Minnesota could face higher energy prices, slower infrastructure development, and increased burdens on low- and middle-income households — all while demand for clean, affordable energy continues to grow."

While Minnesota has been coordinating the application process and is responsible for the granted funds, the JTIQ's proposed projects are sited in the Dakotas, Iowa, Kansas, Missouri and Nebraska, all of which lean heavily Republican.

The grid operators have said the "backbone" projects will unlock 28 GW of capacity and reduce curtailments in the highly congested region along their seam. FERC has approved and reaffirmed the RTOs' proposal to fully allocate the costs of the JTIQ portfolio to interconnecting generation assessed per megawatt. (See *FERC Upholds MISO and SPP's JTIQ Cost Allocation over Criticism*.)

"Federal energy funding plays a vital role in expanding clean energy generation, providing reliable energy transmission [and] creating jobs," Commerce said. "This kind of action directly undermines [DOE's] stated priorities: ensuring energy abundance and maintaining affordability for Americans."

Commerce said it is working with state and federal partners to "assess" the situation and protect Minnesota's interests.

An SPP spokesperson said it is working with Commerce and MISO to "review the order and consider options."

MISO said it is monitoring the "developing situation" and that it will coordinate with its project partners "to understand any potential impacts."

The project's partners have 30 days to appeal the termination; DOE said some award recipients already have begun that process.

DOE *said* in May it was reviewing the "billions of dollars that were rushed out the door" in the Biden administration's final days. It requested additional information to evaluate 179 awards covering more than $15 billion in financial assistance. (See *MISO-SPP JTIQ Fed Funds Caught Up in DOE Review of Grants*.)

The largest cuts were to the Biden administration's Hydrogen Hub initiative. California stands to lose $1.2 billion promised to its $10 billion-plus ARCHES hydrogen initiative, while the Pacific Northwest Hydrogen Hub stands to lose $1 billion.

The *CEO and board chair* of ARCHES called the decision short-sighted but said the initiative would go on without federal funding.

California Gov. Gavin Newsom (D) *went on the attack*: "In Trump's America, energy policy is set by the highest bidder, economics and common sense be damned."

Protest and Praise

"Following a thorough, individualized financial review, DOE determined that these projects did not adequately advance the nation's energy needs, were not economically viable and would not provide a positive return on investment of taxpayer dollars," the department said in a news release.

OMB's Vought identified the states hosting targeted projects as California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Maryland, Massachusetts, Minnesota, New Hampshire, New Jersey, New Mexico, New York, Oregon, Vermont and Washington.

DOE said the grants being terminated had been awarded by its offices of Clean Energy Demonstrations, Energy Efficiency and Renewable Energy, Grid Deployment, Manufacturing and Energy Supply Chains, Advanced Research Projects Agency-Energy and Fossil Energy.

It said 26% of the terminated grants and 41% of the money were awarded between Election Day 2024 and Inauguration Day 2025.

Reaction to the announcement was swift.

U.S. Sen. Adam Schiff (D-Calif.), a frequent critic of Trump, *posted*: "Our democracy is badly broken when a president can illegally suspend projects for blue states in order to punish his political enemies."

U.S. Rep. Troy Nehls (R-Texas) *posted*: "Terrific news. Terminate the Green New SCAM."

U.S. Sen. Patty Murray (D-Wash.), vice chair of the Appropriations Committee, *said*: "President Trump has spent the year hurting families, killing jobs and raising people's costs, and now he and Russ Vought are gleefully using the shutdown they have caused as a pretext to inflict even more pain. … This administration has had plans in the works for months to cancel critical energy projects, and now, they are illegally taking action to kill jobs and raise people's energy bills."

In a *Truth Social post*, Trump suggested there is more to come: "I have a meeting today with Russ Vought, he of Project 2025 fame, to determine which of the many [Democratic] agencies, most of which are a political SCAM, he recommends to be cut, and whether or not those cuts will be temporary or permanent. I can't believe the Radical Left Democrats gave me this unprecedented opportunity. They are not stupid people, so maybe this is their way of wanting to, quietly and quickly, MAKE AMERICA GREAT AGAIN!"

U.S. Rep. Rosa DeLauro (D-Conn.), ranking member on the House Appropriations Committee, *said*: "This was obviously designed as a political attack by the White House targeting Democrats. But the sad reality is that Americans — the middle class, working class and vulnerable — who voted for both Democrats and Republicans will be hurt by this. This is divisive, it is petty, and unfortunately it is exactly what we have come to expect from President Trump and Russ Vought." ■

DOE Seeking Proposals for Power Generation, AI Data Centers

Funding Announced for Puerto Rico, Lithium Mining, Nuclear Fuel

By John Cropley

The U.S. Department of Energy is looking for developers that want to build artificial intelligence data centers — and the power generation to run them — on two nuclear sites.

On Sept. 30, DOE issued a request for private-sector proposals at its *Oak Ridge Reservation*, and the National Nuclear Security Administration issued an RFP for its *Savannah River Site.*

The selection of Oak Ridge and Savannah River for this purpose was *announced July 24* as part of the Trump administration's drive for AI and "energy dominance." Also selected were the Idaho National Laboratory and the Paducah Gaseous Diffusion Plant.

On Sept. 8, the Idaho lab *announced a request for applications* that can be submitted starting Nov. 7.

Proposals are due Dec. 1 for Oak Ridge and Dec. 5 for Savannah River.

Each of the three announcements indicated private-sector partners would be responsible for building, operating and decommissioning their facilities under a long-term lease and for securing utility interconnection. Each indicated that proposals would be evaluated for technological readiness, financial viability, and the details of their plans to complete regulatory and permitting requirements.

A DOE official called the Oak Ridge RFP a step in the transformation of a nuclear remediation site into a nuclear renaissance hub.

An NNSA official called the Savannah River RFP a public-private partnership to accelerate scientific research in pursuit of technology and energy goals. Ten tracts totaling 3,103 acres have been identified there for energy generation and storage co-located with data centers.

Another DOE official said potential uses for approximately 44,000 acres at Idaho include advanced nuclear and enhanced geothermal generation and cold underground thermal storage.

Energy Secretary Chris Wright said July 24 that Idaho, Oak Ridge, Paducah and Savannah River "are uniquely positioned to host data centers as well as power generation to bolster grid reliability, strengthen our national security and reduce energy costs."

Why This Matters

The move is the Trump administration's latest step to ratchet up development of power and AI resources.

Funding Announcements

The Oak Ridge and Savannah River announcements were among a series issued late Sept. 30 by DOE.

The department announced it will reallocate up to $365 million to stabilize and harden *grid infrastructure in Puerto Rico*. It said the island territory has suffered from years of deferred maintenance and mismanagement, leaving ratepayers vulnerable to outages and higher costs, including from storms. DOE's Grid Deployment Office will administer the funding for the upgrades through the Puerto Rico Electric Power Authority.

The DOE Loan Programs Office, meanwhile, has *restructured an October 2024 deal* with Lithium Americas to help fund construction of processing facilities at Thacker Pass, Nev., site of the largest confirmed lithium deposit in North America. The terms give the U.S. government a 5% equity ownership of Lithium Americas and a 5% share of the company's joint venture with General Motors, both in the form of warrants.

The department said the revised deal reduces repayment risk for taxpayers and increases loan resilience; it did not indicate any change to the value of the loan, which *Lithium Americas* and the *Loan Programs Office* placed at $2.26 billion in October 2024.

DOE also selected Oklo, Terrestrial Energy, TRISO-X and Valar Atomics for a program to build advanced nuclear fuel production lines. They join Standard Nuclear, which was *announced in August*.

The five will work in the department's *Fuel Line Pilot Program*, which supports the *Reactor Pilot Program*. Together, the pilot programs are pursuing one of the goals in President Donald Trump's broader vision of a U.S. *nuclear renaissance*: reaching criticality with at least three advanced nuclear reactor concepts outside of National Laboratories by *July 4, 2026*.

Oklo, Terrestrial and Valar also were selected for the Reactor Pilot Program. ■

The Department of Energy is requesting proposals to build and power AI data centers at the Savannah River Site, shown in 2023. | *Savannah River Site*

U.S. Energy Agencies Lay out Plans for Federal Government Shutdown

By James Downing

The federal government officially shut down as the clock turned to midnight Oct. 1 after the two parties failed to agree on a spending package to keep it open at the start of fiscal 2026.

While Democrats and Republicans both blamed each other for the impasse, federal agencies released plans to keep vital employees working and to furlough others, at least once any existing funds are exhausted. For now, both FERC and the Department of Energy have some leftover funds from the previous fiscal year, so they can operate normally, but they will wind down most operations if the shutdown lasts too long.

FERC's *plan* allows it to use leftover funds and will keep it running with all 1,478 employees working. Once that runs out, however, just 60 employees and 18 contractors who are needed to "protect life and property" will remain working, it said.

"It is anticipated that there would be no disruption to FERC operations during a short lapse in appropriations of one to five days," the plan says. "FERC has historically had sufficient previously appropriated funds that remain available to support operations during a short-term lapse. In the event of a lapse extending beyond one to five days, FERC will continue operations using balances from prior years until exhausted."

If the funding is exhausted in a lengthy shutdown, FERC will continue to inspect hydropower dams and LNG projects under construction for safety. It will monitor the reliability of the bulk power system

The U.S. Capitol | *David Maiolo, CC BY-SA-3.0, via Wikimedia Commons*

and threats to energy infrastructure. Some remaining employees will monitor jurisdictional energy markets and offer legal advice to commissioners.

The commissioners are presidentially appointed and Senate-confirmed, so they will continue working, and the office of the secretary of the commission will remain open to release any formal actions publicly.

"Federal employees in offices with funding for salaries continue to report for work as scheduled," DOE's *plan* says. "A prolonged lapse in appropriations may require subsequent employee furloughs. If there is an imminent threat to human life or protection of property, a limited number of employees may be recalled from furlough status."

Like FERC, DOE has historically remained fully open during short lapses of funding that last just one to five days, and if the money runs out, it has been able to wind down operations in half a day.

The department has 15,523 employees, though that was already scheduled to fall to 13,812 at the start of FY26 on Oct. 1 because of the buyouts the Trump administration offered federal workers early in 2025. An additional 1,409 employees are taking the buyout effective Dec. 31, and 71 others have already left.

The Bonneville Power Administration is self-funded, and its 3,266 employees can keep working with regular pay, though 192 were scheduled to leave on Oct. 1 because of the buyout.

"The other power marketing administrations (Southeastern Power Administration, Southwestern Power Administration [and] Western Area Power Administration) will perform functions related to the safety of human life and the protection of property by engaging in controlling and directing power to utilities, transmission of power and repair of the power transmission system," DOE says in its plan.

The Nuclear Regulatory Commission has already started to wind down operations under its plan.

"The NRC has some appropriations for performing high-priority activities, such as operator licensing, time-sensitive licensing actions and activities related to recent executive orders, with a core group of employees," the agency's plan says. "When NRC appropriations no longer support other high-priority activities, the NRC plans to operate at a reduced level for some period of time and to begin a minimal maintenance and monitoring mode in which the NRC will continue to carry out its responsibility to protect public health and safety."

The Bottom Line

FERC and DOE have some leftover funds to keep them open in a short shutdown, but they will wind down most operations if it drags on. Bonneville Power Administration is self-funded and will keep operating regardless, but that is not the case for other power marketing administrations, which will furlough employees.

The law firm Holland & Knight posted a *summary* and links to other federal agencies' plans for the shutdown.

The Maryland Public Service Commission issued a notice saying that utility disconnections are forbidden for any federal workers in the state, noting that Gov. Wes Moore has reminded utilities of that rule.

The White House's Office of Management and Budget and Office of Personnel Management said that federal employees can expect to be paid on time for work through Sept. 30.

The Government Employee Fair Treatment Act of 2019 requires that all employees, including those who are furloughed, get back pay for the shutdown once it ends, though POLITICO *reported* Sept. 24 that OMB could try to fire many federal employees during a shutdown. ■

FERC Identifies 53 Regulations to Sunset in Response to Trump E.O.

By James Downing

FERC issued a *final rule* and related *Notice of Proposed Rulemaking* on Oct. 1 to start "sunsetting" 53 outdated, seldomly used and duplicative regulations in response to an executive order from President Donald Trump (*RM25-14*).

Issued in April, the *executive order*, "Zero-Based Regulatory Budgeting to Unleash American Energy," directed FERC and other energy-associated agencies to conditionally sunset regulations in an effort to trim the Code of Federal Regulations, which approaches 200,000 pages and "has imposed particularly severe costs on energy production." (See *FERC Faces Challenge in Balancing Executive Order and Legal Requirements*.)

"Today's steps are a common-sense commitment to a fast and fair regulatory process," FERC Chair David Rosner said in a statement. "Periodically reviewing, updating and streamlining the commission's regulations helps ensure that they continue to align with our statutory mandates and are focused on high-value activities that strengthen our nation's energy system."

The final rule gives parties a chance to comment on each of the 53 identified regulations, and if parties file "significant adverse comments" against sunsetting any of them, they would go into the NOPR proceeding, in which FERC can respond to those concerns.

A direct final rule is a way to expedite rulemakings and is used for noncontroversial regulatory amendments, allowing an agency to issue a rule without having to go through the review process twice (a NOPR first, then a final rule). The public still gets a chance to challenge the agency's view that its proposed changes are not controversial.

The Bottom Line

FERC issued a direct final rule cutting what it sees as 53 now useless regulations, but it offers commenters a chance to show it is wrong on any of them, which would trigger additional proceedings under a related NOPR.

"Because the commission does not anticipate significant public comments on this rulemaking and considers it to be noncontroversial, the commission is using the 'direct final rule procedure' for this rule," FERC said.

If FERC gets any significant adverse comments on any part of the direct final rule, then it will publish a document removing any such part of the action and address them via the NOPR process.

The commission defines an adverse comment as one where a party explains why the action, or part of it, would be inappropriate, including challenges to its underlying premise, or how it would be ineffective or unacceptable without a change. Comments would have to provide a reason sufficient to require FERC's substantive response in the notice-and-comment process.

FERC will have to respond if a comment causes it to re-evaluate or reconsider its position and to conduct additional analysis; if it raises an issue serious enough to warrant substantive response or to clarify/complete the record; or if it raises a relevant issue the commission had not previously addressed.

The sunsetting of each of the 53 regulations works independently so if any are moved into the NOPR proceeding, FERC can go ahead and sunset the noncontroversial rules.

The executive order gave FERC an independent justification for starting the rulemaking, but FERC noted that it did not direct the commission to rescind or reissue any particular regulation, nor alter its statutory responsibility to issue, alter or rescind rules in line with its core mission of ensuring reliability in an economically efficient manner.

"The commission has further determined, based on its independent policy judgment, that the sunset rule adopted herein is appropriate," FERC said in the final rule. "Regulatory housekeeping, including streamlining and updating our regulations, helps ensure that they align with our statutory mandates, thus alleviating regulatory burdens and allowing regulated industries to focus more deliberately on the types of high-value projects that will augment and strengthen the nation's energy supplies."

FERC headquarters in D.C. | © RTO Insider LLC

The actual regulations proposed for sunset run the gamut of FERC's authority, and many of them have not been used in decades.

One covers "regional transmission groups," which have long since been replaced by ISOs and RTOs, FERC said. The commission proposed to remove "ratemaking treatment of the cost of emissions allowances" because most generators recover those costs through market-based rates.

One rule up for sunset implements the Powerplant and Industrial Fuel Use Act of 1978, which required power plants to switch from oil and natural gas to coal but was repealed in 1987. Gas-fired power plants have been the largest source of generation for years.

FERC also proposed to sunset rules on obsolete procedural and filing requirements such as requiring paper filings, which are no longer in general use at the commission. ■

D.C. Circuit Upholds FERC Approval of TVA's Cumberland Switch to Gas

By Amanda Durish Cook

The Tennessee Valley Authority is closing in on a gas-for-coal swap at its Cumberland plant after the D.C. Circuit Court of Appeals rejected environmental groups' arguments against FERC's environmental review *(24-1099)*.

The court concluded that FERC met its due diligence under the National Environmental Policy Act and the Natural Gas Act and denied the Sierra Club and Appalachian Voices' petition.

TVA plans to retire the pair of coal units at its 2,470-MW Cumberland Fossil Plant and replace one with a 1,450-MW natural gas turbine, which would draw on a new 32-mile pipeline built by Tennessee Gas Pipeline.

Sierra, joined by Appalachian Voices, filed a lawsuit over FERC's assessment of the project, arguing the commission incorrectly credited the pipeline with aiding emissions reductions, conducted a flawed "no-action alternative" analysis, and should have evaluated the plant and pipeline as connected elements (*CP22-493*). (See *TVA's Cumberland Coal-to-gas Plans Press on over Resistance*.)

The group argued that TVA would retire coal generation regardless of the gas turbine construction. But the D.C. Circuit drew on TVA's wording that absent a replacement generation source, it "would need to continue operating the coal-fired units."

The court said FERC did not slip up when it grouped both the coal unit retirement and emissions from the new gas turbine in its downstream emissions analysis. It also said FERC properly considered the pipeline essential to the project.

Sierra also contended that FERC should not have attributed the gas unit with emissions offsets beyond 2035 because that is the latest year Cumberland coal units would operate. It said FERC incorrectly used a decade of emissions comparison from 2036 through 2045.

The court responded that TVA's plans "do not exist in a vacuum."

"Without a replacement generation source with requisite fuel, the TVA might instead upgrade and operate the coal-fired unit well into the future, as the TVA's no-action alternative contemplated. So even though the TVA hopes to replace its coal-fired units by 2035, FERC made the reasonable choice to credit the pipeline with a net emissions reduction covering the entire forecast period," the D.C. Circuit said.

The Bottom Line

The D.C. Circuit Court of Appeals decided all arguments the Sierra Club raised against FERC's assessment of TVA's gas plans at its Cumberland Fossil Plant were without merit.

"Could FERC have taken a different approach? Perhaps. But we must 'defer to agencies' decisions about where to draw the line' in their analyses of 'indirect environmental effects,'" the court said, citing previous case law.

The court likewise brushed aside Sierra's concerns that FERC estimated emissions annually rather than cumulatively. It said "anyone with a calculator — or the ability to perform basic addition" — could perform the conversions and characterized the omission as a "harmless error" at worst.

The court also said the group could not have it both ways by arguing that the pipeline would cause downstream emissions while simultaneously claiming it would not help ease emissions by making a coal retirement possible. It added that it could not criticize FERC for "reasonably" assuming that the gas turbine would be built even if the 32-mile pipeline were rejected.

The D.C. Circuit said FERC properly decided there was a market need for the project because of TVA's 20-year agreement with Tennessee Gas to purchase all pipeline capacity. The court pointed out that TVA and Tennessee Gas are not affiliated, and Sierra did not allege self-dealing.

The court disagreed that FERC should have better scrutinized the market need for the pipeline because TVA is not state-regulated.

"Though the TVA is not subject to state supervision, it is hardly a rogue entity. The TVA must follow a statutorily prescribed 'least-cost planning' framework in making investment decisions; it is subject to congressional oversight and must annually notify Congress of any 'major new energy resource'; and its investment decisions are subject to public notice and comment," the D.C. Circuit said.

The court ruled that FERC was not obligated to contemplate evidence about clean energy subsidies accessible under the Inflation Reduction Act or weigh TVA's choice of natural gas over a renewable alternative, as Sierra argued.

"The Sierra Club is entitled to the expansive view of NEPA … and it is free to argue for robust judicial scrutiny of environmental impact statements. But the Sierra Club's understanding of NEPA is not shared by the Supreme Court," the D.C. Circuit said.

The court said the Supreme Court "repudiated" similar arguments raised in 2025's *Seven County Infrastructure Coalition v. Eagle County, Colorado*, a case centered on approval of an 88-mile railroad line connecting Utah's oil-rich Uinta Basin to the national freight rail network.

"After *Seven County*, the era of searching NEPA review is over — or at least it should be," the court said. ■

The Cumberland Fossil Plant | *TVA*

R Street Scorecard Ranks All 50 States on Electric Competition Policies

By James Downing

Why This Matters

R Street wants policymakers interested in expanding the role of competition to use its scorecard as a source of ideas to move those policies forward.

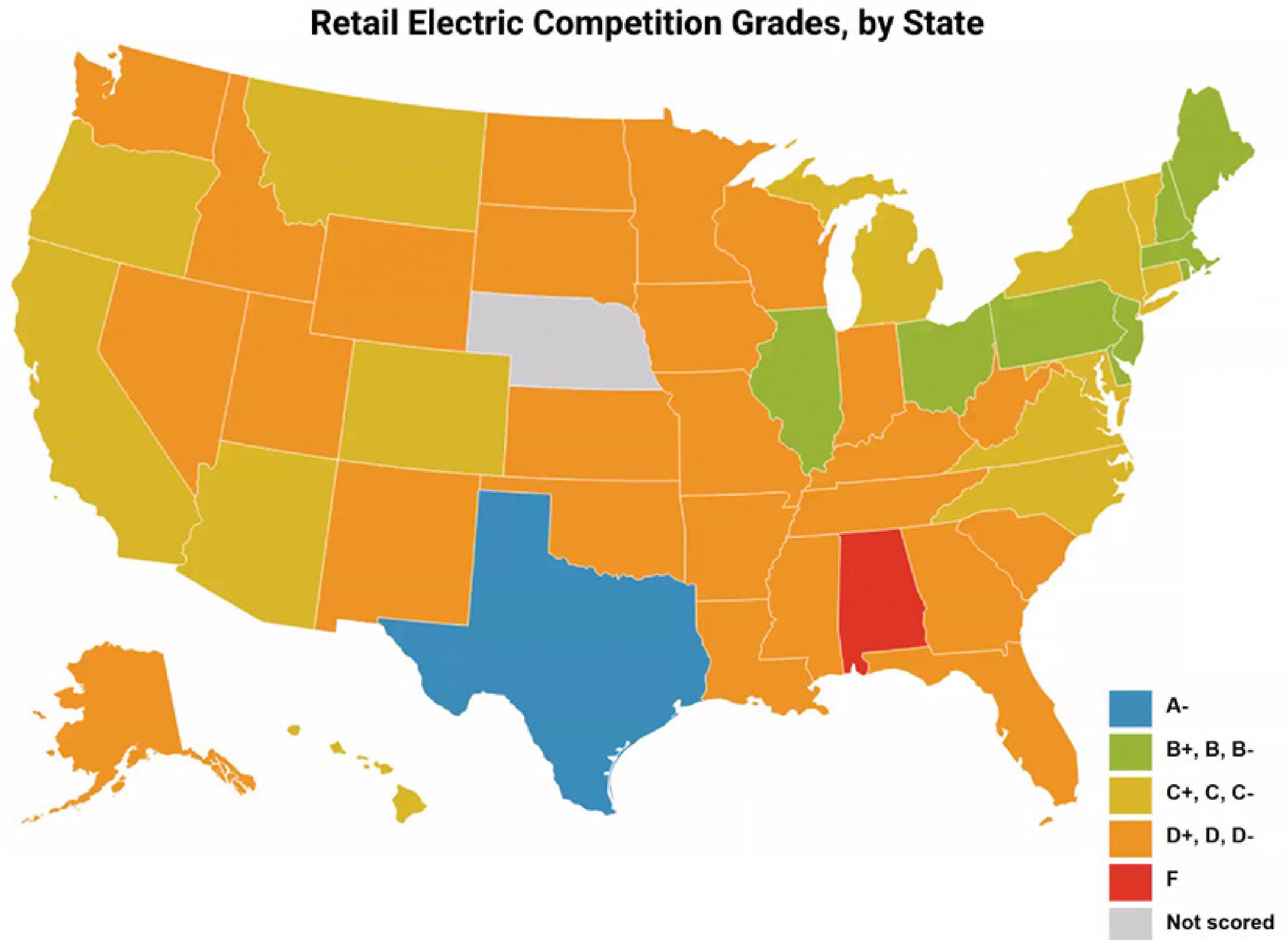
The R Street Institute has ranked the states on their embrace of policies related to competition, which includes retail power markets, RTO membership, smart metering policies and friendliness to distributed resources.

The *scorecard* gives the best grade to Texas, with most customers in ERCOT's territory shopping for their electricity providers, but even it was left at an "A-" because the retail market does not extend to municipal utilities, co-ops or the utilities outside the grid operator's territory.

On the other end of the scale is unranked Nebraska, where consumers are completely served by public utilities and the report's authors lacked access to data to give it a ranking. Alabama was given the lowest grade — the only "F" — as no real competition exists at any level. It also scored low on other metrics like smart meter data and consumer engagement.

"What we want to accomplish with the release of this report and the scorecard is to help policymakers at the state level better understand what are the policy opportunities and what are some of the challenges in given jurisdictions regarding the enablement of more competitive practices in a given jurisdiction," Chris Villarreal, R Street associate fellow and report co-author, said during a *webinar* presenting the report Sept. 30.

The report explains every state's grade, including areas where they can improve,



A map the R Street Institute made showing its grades for state electric competition policies | *R Street Institute* which is possible for even the best-ranked states, Villarreal said.

Other highly ranked states are retail restructured jurisdictions in the Northeast and Midwest, with D.C., Illinois, Ohio and Pennsylvania all getting a "B+." Delaware, Maine and Rhode Island each received a "B," and Massachusetts, New Hampshire and New Jersey a "B-."

The "C" states include a mix of retail restructured states, including some like Maryland or New York that would have ranked higher in years past but have fallen because of policy changes. Maryland recently shut down its retail market for residential consumers, while New York has for years capped retail prices based on a backward-looking, 12-month rolling average of utility rates.

One issue with Maryland is that while the Public Service Commission has started to more actively police bad actors in the retail market in recent years, for a long time it took a light approach to ensuring the market ran fairly, which is one of the metrics the report card uses to rank restructured states, R Street Senior Fellow Kent Chandler said in the webinar.

"Maybe it was too little too late … holding some of those bad actors accountable really did contribute to the ultimate public policy shift there in the legislature," he added.

NRG Energy Vice President of Regulatory Affairs Travis Kavulla agreed with that assessment. (His company serves about 8 million customers in competitive markets around the country, and as a Maryland resident, he has a grandfathered long-term contract from the market.)

Another issue is that the more successful states try to keep their consumers actively informed, such as by requiring multiple notices that a long-term, fixed contract is expiring and customers need to pick another option or they could automatically be shifted to a provider of last resort with more volatile prices, Kavulla said. Some other state commissions, like Pennsylvania's, issue notices to consumers that utility rates are about to go up and consumers can shop for a better deal.

"So now, ironically, basically all residential customers in Maryland, except for people like me, who have grandfathered long-term contracts, are basically strapped to the roller coaster of volatile wholesale energy market pricing, which interestingly, is giving Maryland legislators heartburn that they could have prevented by encouraging more active shopping and more long-term contracting," Kavulla said.

Other states with mixed grades do not have any experience with retail markets, but they have taken moves to join an RTO like some western states, or they have very good policies around distributed energy resources, such as Hawaii.

Just before the report was finalized, Utah was about to join Alabama at the bottom of the pack, but its legislature passed *Senate Bill 132,* which allows more competitive options for large loads, noted Josh Smith, energy policy lead for the Abundance Institute. The law shifts the uncertainties around the future of large loads from data centers looking around for quick and affordable access to the grid away from captive ratepayers.

"There's this kind of uncertainty that ratepayers should not be on the hook for," Smith said. "Instead, that should be something that Google or Meta, or anyone else can check up with a company. … There are lots of these guys who can provide that. And that's the first step that Utah took … in addition to enabling some very niche, I think, but exciting private grid options within the legislation." ■

CEBA Study Shows How Corporate Offtake Helps Clean Energy Get Built

By James Downing

Why This Matters

CEBA's report shows how corporate offtake agreements with clean energy projects cut their risk, enabling more to secure financing and get built.

The Clean Energy Buyers Association released a *study* Sept. 30 that offers hard evidence that its large corporate customer members have materially contributed to the growth of renewables by guaranteeing projects stable revenue streams.

REsurety, which conducted the study for CEBA, analyzed 251 renewable projects in ERCOT, MISO and PJM, which are home to 70% of corporate procurements forecast for the near future. It found that those with power purchase agreements from large buyers are much more financially stable.

"We commissioned this study because we wanted to definitively confirm what we've all known … that voluntary corporate offtake matters: corporate commitments to buy clean energy, [and] get clean energy projects financed and built in the United States," Misti Groves, CEBA senior vice president of U.S. strategy, said in an interview.

Corporate customers contracted for 100 GW of clean energy between 2014 and 2024, which represent about 40% of the total brought online over that decade. Such deals give renewable projects a steady revenue stream that helps them to get financed, the study says.

"Without extensive voluntary commitments by our members and companies, the U.S. may actually struggle to meet energy demand, which is growing," Groves said.

The paper was retrospective, so it focused on purchases of wind and solar, but the same financial benefits can help other technologies such as battery storage, geothermal and nuclear power, she added.

REsurety simulated economic performance of the 251 projects by calculating operating income and debt obligations using historic generation, price and operating cost data from 2015 to 2024 and then identifying sustained periods of financial stress, the study says.

"In contrast to fossil fuel generators, wind and solar projects have low operating costs but relatively high capital expenditures that are financed through a combination of sponsor equity, tax equity and back leverage debt," the study notes. "Once a project becomes operational, it must repay these upfront costs through term loans and dividends to investors. During periods of low wholesale power prices, projects may not earn enough merchant revenue to meet their debt service obligations or their investors' rates of return, which, absent additional revenue sources, could lead to financial distress and potential default."

Offtake agreements with corporate customers cut the likelihood of projects entering periods of financial distress by offering steady income. That means debt interest rates and required debt service coverage ratios are lower for projects with offtake agreements.

Power prices can vary significantly, with the paper pointing to three years this decade: Prices were low in 2020 because of the COVID-19 pandemic, jumped up in 2022 because of expensive natural gas and then were low again in 2024 as cheap gas returned. Over the last two years alone, average prices in PJM ranged from $30 to over $70/MWh.

"For a 100-MW project with a 40% capacity factor, this translates to a swing in annual merchant revenue from $10.5 million to over $24 million," the study reported.

All markets saw benefits from some kind of offtake with renewable energy credit (REC) deals lowering risk somewhat, but virtual PPAs slashing it, the study found. In ERCOT, 38% of merchant projects faced simulated financial distress, which fell to 18% with REC deals and 9% with VPPAs. In MISO the equivalent numbers were 74% for merchant projects, down to 57% with REC deals and just 4% with VPPAs, while PJM saw 71% of merchants with some distress, which fell to 60% with REC deals and 1% with VPPAs.

Corporate offtake is not a subsidy, REsurety Senior Vice President Adam Reeve said. Tax credits have provided a subsidy to renewables, but offtake deals are at market prices.

"The benefit of the corporate purchase is transferring risk away from the project that enables them to secure debt financing and then get built," Reeve said in an interview. "Debt financing is the cornerstone of infrastructure investment around the world. We're doing a lot of infrastructure investment in the U.S. We need that right now."

Regardless of the presence of tax credits for energy projects, that risk transfer is a benefit that will help get power plants built, he said.

"Without continued corporate risk transfer … for these long-term, stable revenues, we won't see the growth of low-carbon power in the U.S. that I think we would otherwise," Reeve said.

The study focused on three wholesale power markets, but it argued that the same would hold true for other markets.

"It's no accident that that voluntary contracts for clean energy happen in deregulated wholesale markets rather than regulated markets," Groves said. With its transparent wholesale prices, the construct helps corporations enter into VPPAs and other offtake deals, she added.

"In this next year, as renewable energy projects aim to meet deadlines for tax credits, the support and cooperation of corporate buyers will give developers the confidence to advance spending to secure tax credits to reduce the cost of renewable energy," Joan Hutchinson, Marathon Capital's managing director of offtake advisory, said in a statement. ■

Reports Quantify Changes in U.S. Energy Storage Sector

Strong Growth in 2025 Faces Mix of Headwinds, Tailwinds in 2026 and Beyond

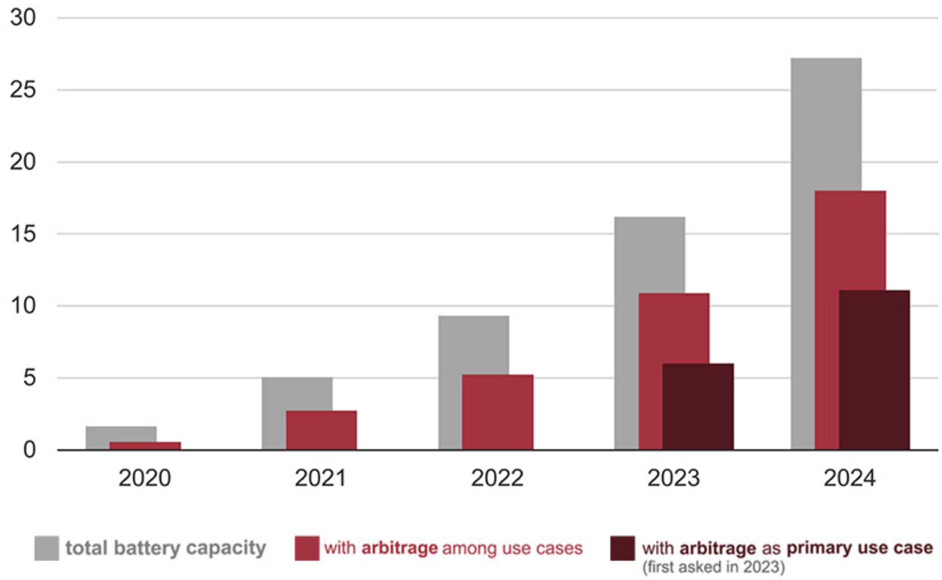
By John Cropley

New reports give a picture of a U.S. energy storage sector accelerating even faster in 2025 despite policy changes but facing a potential slowdown because of those same policy changes.

American Clean Power Association and *Wood Mackenzie* reported 5.6 GW of new capacity was installed in the second quarter, a quarterly record.

Troutman Pepper Locke examined the heightened risk facing U.S. storage developers amid the regulatory and tariff uncertainty created by the Trump administration and Congress.

And the *U.S. Energy Information Administration* reported that this rapidly expanding class of grid assets increasingly is being used for arbitrage, rather than for grid-stabilizing functions.



The U.S. Energy Information Administration reports a sharp increase in U.S. utility-scale battery capacity in the past four years. | *EIA*

ACP and WoodMac

In their latest "*US Energy Storage Monitor*" report, released Sept. 26, ACP and Wood Mackenzie said 4.9 GW of utility-scale storage was added in the second quarter of 2025, 63% more than in the same quarter of 2024.

Residential installations totaled 608 MW, up 132% year-over-year, and community/commercial/industrial installations totaled 38 MW, up 11%.

Texas, California and Arizona each added more than 1 GW of utility-scale storage. California, Arizona and Illinois accounted for most of the residential growth. More than 70% of the commercial and industrial installations were in California and New York; community storage deployments remained limited due to cost and policy constraints.

The report predicts U.S. storage capacity will reach 87.8 GW by 2029.

But headwinds facing the sector could reduce utility-scale storage installations 10% in 2027, the report indicates.

And over the next five years, those headwinds could reduce the buildout by 16.5 GW, said Allison Weis, global head of storage at Wood Mackenzie.

"After 2025, utility-scale storage projects must comply with new, stringent battery sourcing requirements to receive the ITC," Weis said. "While domestic cell supply is ramping up, supply chain shortages are possible, although developers are continuing to consider supply from China to fill in any gaps. A rush to start construction under the more certain near-term regulatory framework uplifts the near-term forecast. Projects that have not met certain milestones by the end of 2025 are at risk of exposure to changing regulations. There is additional downside risk if further permitting delays threaten solar and storage projects."

Why This Matters

Heavy interest in U.S. energy storage development is countered by potential cost and policy headwinds.

Troutman Pepper Locke

Troutman Pepper Locke drilled down on these headwinds in "*Brave New World: What's Next for US Energy Storage After OBBBA and Amid Continued Tariff Risk*?"

In its announcement of the report Sept. 23, the law firm said the sector was "bruised but buoyant amid regulatory and tariff uncertainty" and detailed how developers, investors and lenders have prepared for these risk factors.

The report also explains why it remains confident about the storage sector's growth trajectory in the wake of the One Big Beautiful Bill Act (OBBBA), which dealt so much pain to other parts of the clean energy industry.

"Energy storage's versatility of use cases has untethered it from the fate of wind and solar to a meaningful degree," said co-author Vaughn Morrison, a partner in the firm.

Andrew Waranch, CEO of storage developer Spearmint Energy, explained the economics: "So much of the power market and power price is set by expensive and old generators that only need to operate during ramp times in the morning and evening. In contrast, batteries can solve that quickly and cheaply with extremely high reliability."

The national origin of the batteries will be an important factor moving forward, said John Leonti, a partner in the law firm.

He said: "Although the impact of the OBBBA on energy storage is less severe than some feared, the ambition to onshore battery component manufacturing and the attendant Foreign Entities of Concern (FEOC) provisions issue significant supply challenges for the industry moving forward."

Headwinds and tailwinds for U.S. battery energy storage systems will mix as demand for their services rises while heavier loads are placed on an aging grid, to a degree that far outstrips U.S. production capacity, the report states.

The majority of battery components come from China, where tariffs and FEOC restrictions will boost material costs.

Energy Information Administration

In an analysis released Sept. 22, the EIA tracks U.S. utility-scale battery storage capacity in the 2020s.

The 230 plants operational in 2020 had a nameplate capacity of 2.09 GW. The 786 plants operational in 2024 had a nameplate capacity of 27.82 GW.

EIA in its surveys has been asking operators since 2020 if arbitrage was among the use cases for their batteries, but it was only in 2023 that EIA started asking if arbitrage was the primary use case.

It found that arbitrage was among the use cases for 66% of all utility-scale battery capacity in 2024 and the primary use case for 41%.

The most common other primary uses, in descending order, were frequency regulation, excess wind/solar generation, system peak shaving, load management and co-located renewable firming.

The EIA data shows other shifts:

- Lithium-ion batteries accounted for 86% of the projects in 2020 and 96% in 2024.
- Non-CHP IPPs operated 54% of facilities and 75% of capacity in 2020; that jumped to 72% of facilities and 86% of capacity by 2024.
- Electric utilities operated 35% of facilities and 23% of capacity in 2020; that dropped to 23% of facilities and 10% of capacity by 2024.
- Only 22% of facilities and 17% of capacity was operated in support of transmission and distribution assets in 2024.
- As of 2024, there were 558 facilities with a combined nameplate capacity of 74.64 GW classified as "proposed"; here again, non-CHP IPPs are behind the great majority of the proposals, the great majority of which would entail lithium-ion batteries. Arbitrage would be the primary or secondary use for 402 projects with a combined capacity of 56.3 GW.

EIA breaks U.S. utility-scale battery capacity into three geographic categories: CAISO, ERCOT and everywhere else. 2024 ended with nearly 12 GW of capacity online in CAISO, approximately 8 GW in ERCOT and roughly 7.5 GW in the rest of the country.

ERCOT showed the heaviest activity, with roughly 7 GW sometimes used and 4 GW primarily used for arbitrage.

Arbitrage was somewhat less frequent in CAISO and much less frequent in the rest of the country, where only about 2 GW was primarily used to facilitate buying electricity when cheap and selling it while expensive. ■

CPUC Judge Proposes Ordering 6 GW of New Resources as Tax Credits Fade

Stakeholders Concerned About Possible Procurement 'Frenzy'

By David Krause

A California Public Utilities Commission judge has proposed that the commission order an additional 6 GW of capacity for the state between 2029 and 2032 to get ahead of disappearing federal tax credits and loans for renewable energy resources.

Under the proposal, 3 GW of additional procurement would be required by 2029, 4.5 GW by 2031 and 6 GW by 2032.

While ordering an additional 6 GW of resources now might be "premature," the extra capacity "would likely still be needed to achieve long-term goals," CPUC Administrative Law Judge Julie Fitch said in a Sept. 30 *ruling*.

The additional resources are needed in light of the California Energy Commission's 2024 Integrated Energy Policy Report (IEPR) demand forecast, which shows significant load growth between 2028 and 2032. Compared with the 2023 IEPR, the 2024 IEPR shows an additional 2 GW of load needed by 2030 and 5.8 GW by 2040.

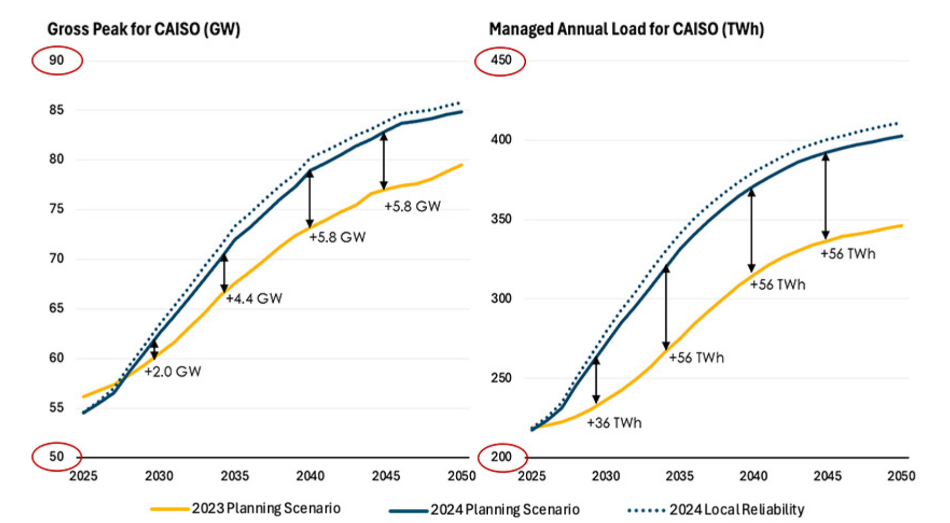
The bump in future load is caused by forecasts for new data centers, increased electric vehicle charging and expanded building electrification, the ruling says. Additionally, a decreased amount of behind-the-meter solar and storage will be installed in the coming years, the CEC's load forecast showed.

Current tax policies that make renewables more cost competitive are assumed to last only through 2029, CPUC staff said in a *presentation* associated with the ruling. If the federal investment tax credit and production tax credit are eliminated, ratepayers would experience "negative cost impacts" related to procurement of renewable resources, the ruling says.

"Ordering procurement now may help load-serving entities take advantage of any projects eligible for expiring federal tax credits or other incentives, such as grants or loans, that may be at risk at the federal level," the ruling says.

However, some stakeholders are concerned that a new procurement order could increase ratepayer costs due to a "frenzy of procurement by a large number of LSEs in an already tight market," it says.

Many LSEs said they are already procuring as many resources as possible. Ordering them to find more resources would "not assist in the areas where procurement is delayed because of interconnection and permitting issues or supply chain issues," the ruling says.



The CEC's 2024 IEPR electricity forecast increased the amount of resources needed to meet demand in CAISO's territory. | *CPUC*

Why This Matters

California is scrambling to ensure the state has enough affordable, and clean, electricity in the future to power data centers and electric vehicles, while tax credits for renewables are set to expire.

The ruling does not specify what types of energy resources are needed or in what amounts for the proposed 6 GW. As additional energy storage is added to the grid, there might be "a question about the need for energy resources to generate sufficient additional electricity to charge the storage," the ruling says.

In the ruling, Fitch also asked stakeholders to provide feedback about whether repowering existing energy facilities should be eligible to count toward "new" resources.

In most past decisions, the commission did not allow procurement to include repowering facilities or tapping into existing clean energy or natural gas resources, but in the late 2020s and early 2030s, certain resources will be of retirement age, Fitch said in the ruling.

Fitch also asked stakeholders to respond to certain questions related to new procurement, such as:

- Should the new procurement be for generic capacity, or should there also be an energy component due to the declining effective load-carrying capability of battery storage?
- Should a procurement order specify particular types of resources, such as clean long-duration energy storage, or should the order be for generic capacity resources?

Stakeholder comments on the proposal are due Oct. 22. ■

PacifiCorp Asks WPP to Delay WRAP 'Binding' Phase Commitment Date

Request Comes 1 Day After WPP Announces Binding Phase for Winter 2027/28

By Henrik Nilsson and Robert Mullin

PORTLAND, Ore. — PacifiCorp has asked the Western Power Pool's Board of Directors to allow Western Resource Adequacy Program participants to defer their decision to commit to the program's binding phase by at least one year, saying the emergence of day-ahead markets in the West and other developments warrant reconsideration.

Following a question during a panel discussion at a Western utility conference about PacifiCorp's position on WRAP, Michael Wilding, vice president of energy supply management at PacifiCorp, said WRAP "is an incomplete product."

"We see the value in the regional coordination," Wilding said at the fall joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB) in Portland. "We want to continue to work with the region. But right now, we need … some time to evaluate where the program's going."

Wilding's comments came in response to a question about a *letter* issued by PacifiCorp on Sept. 30 in which CEO Cindy Crane said moving forward with the current Oct. 31 commitment date "would be imprudent and not in the best interest of our customers."

The letter came one day after WPP announced that WRAP is moving forward with the first binding season in winter 2027/28 after receiving commitments from a "critical mass" of participants. (See related story *WRAP 'Binding' Phase Set for Winter 2027/28 After Utilities Affirm Commitment*.)

Crane noted in the letter that work by the WRAP Day-Ahead Market (DAM) and Planning Reserve Margin (PRM) task forces highlights developments that have emerged after WRAP was formed and that the program must now adapt to.

For example, the DAM Task Force is developing a proposal aimed at realigning WRAP's "operational subregions with the footprints of CAISO's [Extended Day-Ahead Market] and SPP's Markets+, replacing the legacy MidC/SWEDE structure," the letter stated.

"This would fundamentally change how capacity planning, the operational program, and the settlement of holdback and energy deployments are managed," according to Crane.

Western Power Pool's Rebecca Sexton on an Oct. 1 panel at the CREPC-WIRAB conference in Portland, Ore. | © *RTO Insider*

Why This Matters

PacifiCorp's request suggests WRAP participants have diverging views about how prepared the region is for the program's penalty phase.

Additionally, the PRM Task Force is considering new tools for setting planning reserve margins, which could impact participants, Crane contended.

"Active discussions are occurring relating to mechanisms to defer deficiency charges for entities making strategic investments in new resources, recognizing the need for flexibility as the region transitions to new market structures," according to the letter.

Crane urged the board to defer the binding decision by at least one year to implement changes and allow for further stakeholder input.

WPP told *RTO Insider* that the organization's board and staff are reviewing the letter.

WPP launched the WRAP in response to industry concerns about resource adequacy in the West.

Under the program's forward showing requirement, participants must demonstrate they have secured their share of regional capacity needed for the upcoming season. Once WRAP enters its binding phase, participants with surplus capacity must help those with a deficit in the hours of highest need. (See *WRAP Task Force Explores Optimization for Day-ahead Markets*.)

The binding phase also includes penalties for participants that enter a binding season with capacity deficiencies compared with their forward showing of resources promised for that season.

In 2024, the binding phase was postponed by one year at the request of participants, who said they were facing challenges including supply chain issues, faster-than-expected load growth and extreme weather events that would make it difficult for them to secure enough resources and avoid penalties. WRAP members voted in September 2024 to delay the binding phase until summer 2027, but that date was pushed forward. (See *WRAP Members Vote to Delay 'Binding' Phase to Summer 2027*.)

'Some Folks Will Leave'

Speaking on a separate Oct.1 panel at the CREPC-WIRAB conference, WPP Chief Strategy Officer Rebecca Sexton did not mention the PacifiCorp letter, but acknowledged the challenges facing the WRAP, saying the program is "living in a world of dichotomies" in which "lots of things are true at the same time."

"We are in a resource adequacy crisis, and we also have utilities who are working really hard to close the gap, working really hard, and it feels like the goalposts keep moving with all of these challenges," she said.

In her presentation, Sexton spelled out the top five challenges facing WRAP members — many of which had been cited by participants in their previous request for a delay, including: "significant" load growth, supply chain constraints for project developers, interconnection delays for resources, resource retirements and fuel supply issues.

Sexton said part of the program's "value proposition" is its binding forward showing, which tells participants how much capacity they must bring to the table to meet regional needs. The binding operational program is the other part, enabling participants with surpluses to assist those with deficits in the hours of highest need.

"So when the operating time horizon is similar, we motivate the participants to deliver to each other. If you're having a better day than planned, then you might get an obligation to deliver to someone who's having a worse day than planned," Sexton said.

She pointed out that while participation in the WRAP is voluntary, once committed, participants are expected to meet their obligations to avoid a "tragedy of the commons situation" in which some participants lean too heavily on others to meet their own needs.

Sexton noted that WRAP participants are working "to evolve the program to make sure that it's one they want to stay in" and "that they think is really solving this regional need."

She pointed to various WRAP efforts, including stabilizing planning reserve margins to make them more predictable and working to "best integrate" with day-ahead markets to optimize delivery, which she called a "real opportunity" for the program.

But Sexton acknowledged yet another "dichotomy" facing WRAP: that "the reason why we need the resource adequacy program is also increasing, and it's really challenging to subject yourself to this voluntary compliance program and get the resources in place to meet the metrics."

"So we are having conversations [with participants]. We expect that some folks may not stay in the program. We know some folks will leave," she said. ■

Solar Dominates CPUC Tx Plan Recommendations Despite Cost Increases

Limited Wind Resource Portfolio also Included

By David Krause

The California Public Utilities Commission (CPUC) is recommending the state build another 68.5 GW of new solar generation resources by 2045, despite new tariffs on imported goods and the planned elimination of certain federal tax credits that will increase the cost of renewables.

The CPUC's new order instituting rulemaking *(R 25-06-019)* issued Sept. 30 includes the agency's 2026/27 Transmission Planning Process (TPP) base case energy resource portfolio, which CAISO will use to help decide what new transmission infrastructure is needed in the state.

Build rates for solar resources in California have averaged between 1 and 3 GW/year, but the base case portfolio calls for build rates between 4 and 7 GW/year going forward.

The largest amount of new solar generation in the base case — about 19 GW — would be built in San Diego Gas & Electric's and Southern California Edison's "Arizona" region.

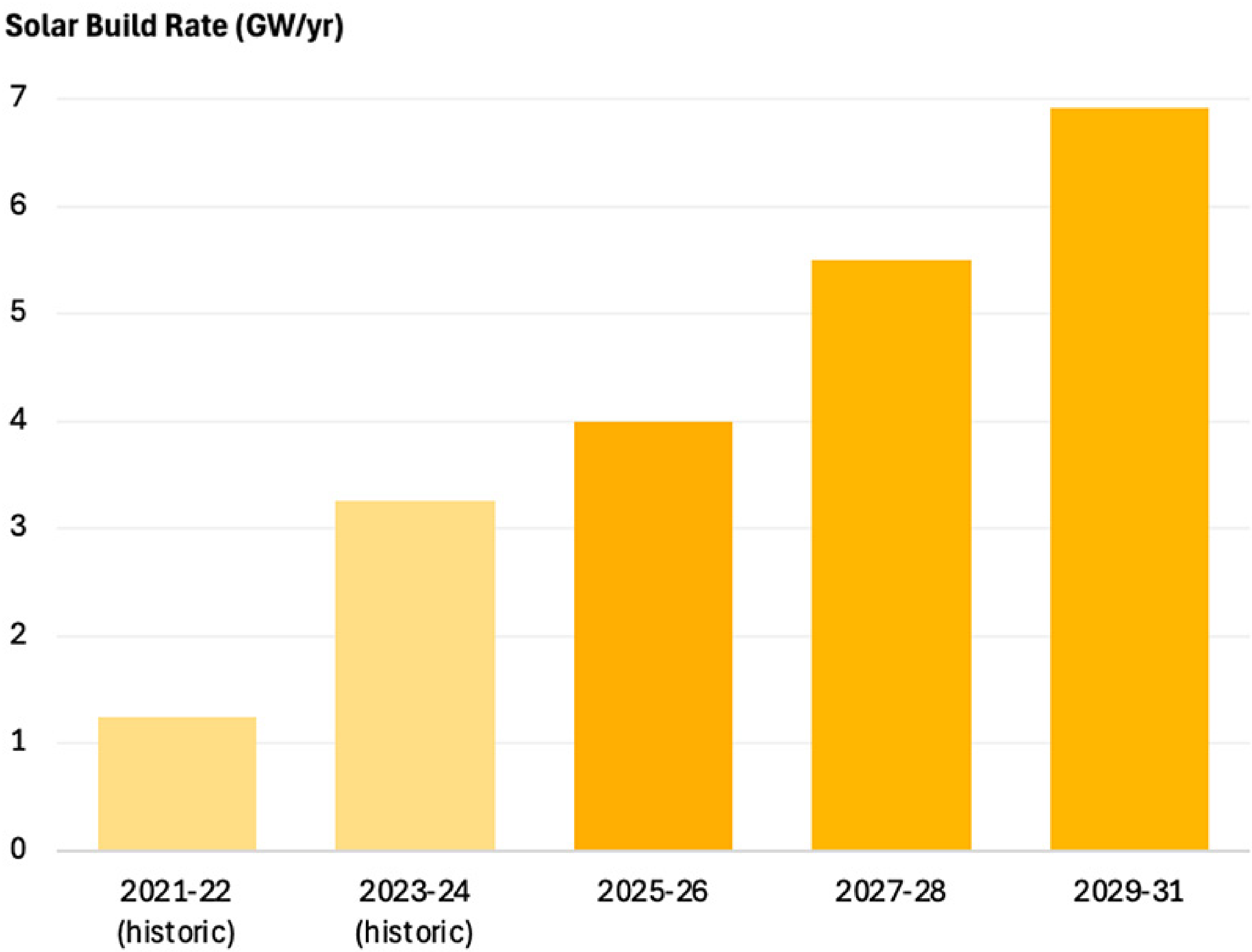
The additional energy resources and accelerated build rates stem from the California Energy Commission's 2024 Integrated Energy Policy Report (IEPR), which showed higher demand and peak load than the 2023 IEPR, the ruling says.

Why This Matters

The CPUC's order indicates the agency still sees a strong future for solar in California despite recent federal policy setbacks.

The state now needs up to 30 GW more capacity than estimated in the 2025/26 TPP.

In the ruling, stakeholders told the CPUC that the elimination of certain tax credits associated with renewables will have



Recommended solar build rates in CAISO's territory | *CPUC* "negative cost impacts on ratepayers."

Utility-scale solar is expected to see a levelized cost increase of 73 to 90% due to the elimination of the federal investment tax credit and production tax credit, while levelized costs for onshore wind are expected to rise 14 to 150%, the order says.

The CPUC's model assumed that wind and solar tax credits will end, specifically for projects that are not under construction by July 4, 2026. Energy storage and clean firm technologies retain tax credit eligibility through 2032, the order says.

RTO Insider asked the CPUC why its resource model recommended such a significant amount of additional solar generation despite the increasing costs.

"Though [the model] now accounts for the large increasing cost of solar due to new tariffs and tax credit eliminations, there are also increases in cost for other candidate resources," the CPUC responded. "Overall, the cost of the energy transition has increased due to the loss of the tax credits. Despite recent cost increases, solar energy remains a competitive avenue for reaching the state's clean energy goals and steadily growing demand."

As for tariff impacts, solar generation and lithium-ion battery storage will see the largest cost increases because most of their components are built in China and Southeast Asia, the order notes. The model's resulting weighted average tariff is 29% for onshore wind, 70% for utility-scale solar and 122% for lithium-ion battery storage, the ruling says.

The battery storage supply chain is uniquely dependent on imports from China, which is subject to some of the highest tariffs overall under current federal policy, the ruling says. The CPUC's resource model assumes that the current tariff policy will last through 2029. However, the model does not consider the fact that China has been flagged as a foreign entity of concern.

Wind and Other Portfolios

In the base case portfolio, out-of-state wind capacity needed by 2045 came in at 19 GW — the second-largest volume of new resources, behind solar. In-state wind finished in third place for needed generation resources, totaling 7.7 GW by 2045.

Additional battery storage resources came in at about 25 GW in the base case portfolio.

The rulemaking also included a "least-cost" resource portfolio, which recommended slightly more solar generation — 71.5 GW.

And the ruling included a "limited wind" sensitivity portfolio, which the CPUC built due to the "recent lack of wind development in California, the recent increased difficulty of permitting wind in California and the recent changes in federal policy toward wind projects," the rulemaking says.

The limited wind portfolio is not intended as a policy preference but rather is meant to show transmission capacity needs if less wind capacity is built in the coming years, the ruling says. Offshore wind shows 0 GW in this portfolio, whereas in the base case portfolio, California is projected to have 4.5 GW of offshore wind by 2045.

Solar needs soar to 83.2 GW by 2045 in the limited wind portfolio. ■

WRAP 'Binding' Phase Set for Winter 2027/28 After Utilities Affirm Commitment

Program Secures 'Critical Mass' After 11 Utilities Recommit Ahead of Deadline

By Henrik Nilsson

Why This Matters

The 11 utilities' recommitment to WRAP brings the start of the program's "binding" phase into clearer focus.

The Western Power Pool's Western Resource Adequacy Program (WRAP) has secured enough participants for the program to enter the first binding phase after 11 utilities reaffirmed their commitment in a Sept. 29 letter.

The utilities' assurance that they will remain in the program comes shortly before the two-year opt-out deadline. The *recommitment* means WRAP has secured a "critical mass" of participants to move forward with the first binding season in winter 2027/28, WPP said in a statement on its website.

The letter is signed by Arizona Public Service, Avista, Bonneville Power Administration, Chelan Public Utility District, Clatskanie Public Utility District, NorthWestern Energy, Powerex, Puget Sound Energy, Salt River Project, Tacoma Power and Tucson Electric Power.

"As utilities that have actively participated in WRAP since its inception in 2019, we reaffirm our commitment to the program and to continue building on its strong foundation," the letter stated. "The signatories to this letter will remain in WRAP and participate in binding operations starting in winter 2027/28."

"The participants who have voiced their commitment to the program represent a broad and diverse group of organizations," WPP said in its statement. "In addition to those who signed the letter, there are more participants we expect to remain in WRAP, some that recently joined and even more joining in upcoming years."

WPP launched the WRAP in response to industry concerns about resource adequacy in the West. (See *WRAP Participants Find Value in Program's Nonbinding Phase*.)

Under the program's forward-showing requirement, participants must demonstrate they have secured their share of regional capacity needed for the upcoming season. Once WRAP enters its binding phase, participants with surplus capacity must help those with a deficit in the hours of highest need.

The binding phase also includes penalties for participants that enter a binding season with capacity deficiencies compared with their forward showing of resources promised for that season.

In 2024, the binding phase was postponed by one year at the request of participants, who said they were facing challenges including supply chain issues, faster-than-expected load growth and extreme weather events that would make it difficult for them to secure enough resources and avoid penalties. WRAP members voted in September 2024 to delay the binding phase until summer 2027, but that date was pushed forward. (See *WRAP Members Vote to Delay 'Binding' Phase to Summer 2027*.)

WRAP has also become a focal point in the competition between SPP and CAISO. Both are developing separate day-ahead markets and are trying to attract as many participants as possible. Supporters of SPP's Markets+ have highlighted that participants in the market must join WRAP, while arguing that CAISO's Extended Day-Ahead Market (EDAM) contains no RA framework. Most of the signatories to the letter have committed to Markets+.

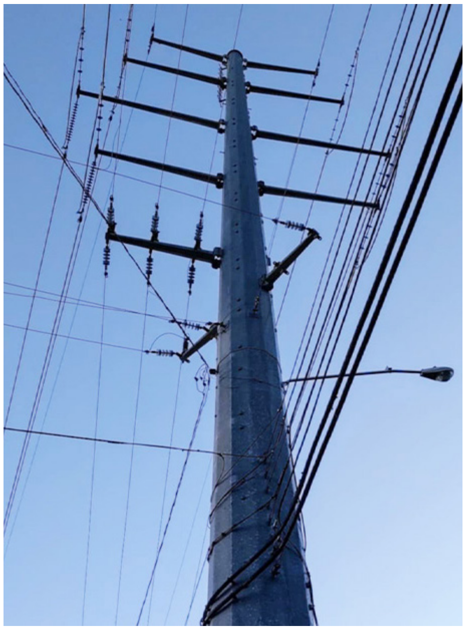
The organizations wrote in the Sept. 29 letter that WRAP continues to evolve, highlighting the "multiple task forces" involved in developing the program. One such task force is the WRAP Day-Ahead Market (DAM) Task Force that is working to make the program compatible with Markets+ and EDAM. (See *WRAP Day-Ahead Market Task Force Moves Forward on Concept Paper*.)

"We are confident the program will continue to grow and adapt," the organizations said. "The program's design will evolve alongside emerging day-ahead markets, while its broad participation ensures the collective savings and reliability benefits are delivered for customers."

The utilities noted also that some current signatories to the program may still exit, but added that "the participants signing this statement represent only a portion of the utilities committed to WRAP's long-term success."

"By stepping forward now, we intend to demonstrate early momentum, provide confidence to those still weighing their options and signal that WRAP will continue to deliver value as it enters its binding phase," the organizations wrote.

"We remain confident in the fundamental premise of WRAP and the value it brings," WPP said. "Over the next two years, in addition to onboarding new members, we will focus on changes and updates to optimize the program and respond to concerns raised by participants and stakeholders. This will allow WRAP to maximize the benefits it delivers when binding operations begin and help address the growing challenge of resource adequacy." ■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‘Above-normal’ Chance of Large Wildfire in Southern Calif. This Fall

La Niña also Increases Risk of Flooding

By David Krause

Southern California faces an above-normal chance of a significant wildfire in the coming months, less than one year after a set of deadly fires burned thousands of acres and structures in the Los Angeles region.

“Southern California is now under moderate to severe drought, with just one little area of extreme drought over the lower desert,” Jeff Fuentes, assistant chief of the California Department of Forestry and Fire Protection (Cal Fire), said in an Oct. 2 winter readiness workshop hosted by CAISO’s RC West. “Santa Ana wind events will warm atmospheric conditions and drive above-normal fire potential during October through December.”

The South Coast region of Southern California shows the highest fire potential in the state because precipitation will likely be well below normal there from now through January, Fuentes said.

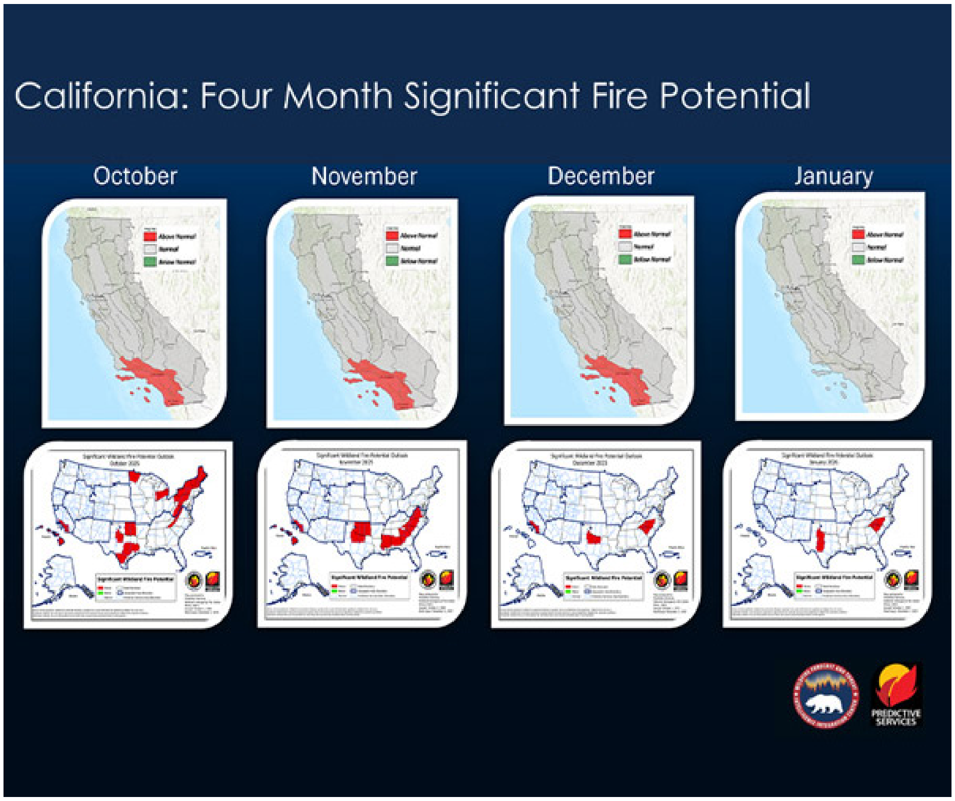
About 10 months ago, a group of massive wildfires ignited in Southern California, including the Eaton Fire, which burned about 14,000 acres, caused 19 deaths and 22 missing people, and destroyed more than 9,000 structures.

Rainstorms are expected in the region in late December or early January 2026. After these storms, “we get back to normal fire potential statewide,” Fuentes said.

“[But] this doesn’t mean the wildfire season is over. All it takes is some dry events, some dry conditions and offshore winds … to kind of create those dangerous fire conditions,” Fuentes added.

Why This Matters

Wildfires have grown in size and frequency this century in California, increasing the chance of harm to the state’s residents and electric grid infrastructure.



Fire potential in California over the next four months | *CAISO*

So far this year, over 7,000 fires in the state have burned about 500,000 acres — a slight increase in fires compared with 2024. About 1,000 more fires this year have ignited compared with the 5-year average.

Water Outlook

As for precipitation, California ended the 2024/25 water year at about 91% of the normal precipitation level, said Jessica Stewart, CAISO senior energy meteorologist. California’s water year runs from Oct. 1 to Sept. 30.

For the new water year, there is about a 71% chance of La Niña through fall and about a 54% chance through February. The stronger the La Niña signal, the lower the chance California has to see above-average snowfall, Stewart said.

La Niña events have “historically resulted in more dry than wet years, but research also suggests that even as the climate grows hotter and drier overall, the precipitation that California does receive will arrive in stronger storms, increasing the risk from flooding,” the California Department of Water Resources (CDWR) said in a Sept. 30 *press release*.

“There is no such thing as a normal water year in California,” CDWR Director Karla Nemeth said in the release. “Just in the past two winters, deceptively average rain and snowfall totals statewide masked the extremely dry conditions in Southern California that contributed to devastating fires as well as flood events across the state from powerful atmospheric river events.”

In the coming months, the precipitation forecast is below average from the San Francisco Bay Area to the southern border of California, Stewart said. However, the ongoing drought in California and the West worsened between 2024 and 2025. Extreme flooding is a critical concern this year due to a warmer atmosphere, which causes an increased amount of moisture and more powerful storms, DWR said in the release. ■

FERC Focused on Load Forecasting Challenges, Chang and See Say

Commissioners Spoke at CREPC-WIRAB Conference

By Henrik Nilsson

PORTLAND, Ore. — FERC Commissioners Judy Chang and Lindsay See endorsed a recent letter by Chair David Rosner on the sharing of best practices around load forecasting in light of growing demand driven by data centers.

The commissioners discussed the letter in separate panels during the fall joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB) on Oct. 2.

Both commissioners view the rapid growth of data centers as an opportunity for the U.S. economy but argued that development must be coupled with efficient planning and investments. Additionally, collaboration between state and federal authorities is key, they said.

"We have to work well with the states and the RTOs for this," See said. "This is an area where we do not have all of the authority, even primary authority … a lot of it is more of a regional and state issue. But we do have an important role. We have to work well together. I think load forecasting and transparency … is one of the biggest challenges in front of us."

See pointed to Rosner's letter on Sept. 18, in which he asked all six jurisdictional ISOs and RTOs for information on best practices around load forecasting in light of growing demand driven by data centers and other sources. (See *FERC Focusing on Large Loads, Clearing the Decks Under Rosner*.)

The letter raises questions FERC and regulators across the country "keep hearing over and over … how do we know that load is real? When is it coming? Where is it coming from?"

"There are real dangers to both overbuilding and underbuilding, and trying to figure out how do we deal with that kind of uncertainty and load forecasting, I think, is one of the most important issues in front of us," See added.

The industry is considering several alternatives to dealing with forecasting uncertainties, including requiring more collateral to ensure the viability of projects, See said. This is an idea discussed by, for example, the Bonneville Power Administration as it plans to overhaul its interconnection process. (See *Utilities Back Some BPA Transmission Updates, Hesitate on Others*.)

"I think that there's a lot of really important solutions that are being discussed," See said. She noted FERC may not always be able to mandate those solutions, but the agency can facilitate information sharing between entities and function as a "central repository to help encourage that conversation. I think that's critical."

FERC Commissioner Judy Chang on an Oct. 2 panel at the CREPC-WIRAB conference in Portland, Ore. | © *RTO Insider*

In a separate panel at the CREPC-WIRAB conference, Chang also discussed the letter. She said forecasting is made more difficult when load projections can each produce different results, saying the "uncertainty span is huge."

Chang noted that data center developers are shopping around for good deals, which can further complicate load forecasting. For example, a developer could discuss a project with Arizona utilities while simultaneously having conversations with utilities in Iowa, "and you wouldn't know that," Chang said.

"I think it takes some time for us to actually see the trends and to see how much load materializes," Chang said. "I think the goal of that letter is to really encourage RTOs — and it starts with RTOs — to kind of say, 'how are you looking at these uncertainties? Are there sort of best practices, are there ways that can be shared across regions?'"

FERC's role, Chang said, is to "lay the rules of the road" and clarify regulations on how to efficiently build out the infrastructure needed to meet the challenges.

"This is a new challenge," Chang said. "I don't think it's the first time we have large loads, but I think it is the first time we have these very large loads, localized in certain areas and with a fast pace."

See and Chang both emphasized transparency, with See saying that information sharing between regions around calculating reserve margins and emergency protocols "is really important as we're having this broader conversation."

Chang said also that the challenge is to build enough resources when costs are high and labor and material supply chains are constrained.

"I think it is important to make sure that the signals are aligned with the needs to make sure that we are very clear and transparent about how the resource adequacy criteria are set," Chang said. ■

Texas PUC Approves Permian, Outside ERCOT Transmission Projects

By Tom Kleckner

Texas regulators have approved the first transmission project in the Permian Basin Reliability Plan, Oncor's proposed 23-mile, 345-kV double-circuit line east of El Paso in far West Texas (*57828*).

The Public Utility Commission endorsed the project, along with several others also out of ERCOT's territory in West and East Texas, during its Oct. 2 open meeting, which lasted a little more than half an hour. The project, which also includes substation work, is expected to cost $216.1 million. It was previously approved by ERCOT.

The commission added language to the *order* requiring Oncor to make quarterly progress reports. The utility told the PUC it expects the facilities to be energized by December 2027.

The Permian Basin plan is a result of *House Bill 5066*, passed by the Texas Legislature in 2023 and signed into law by Gov. Greg Abbott. It required the PUC to approve a reliability plan for the Permian Basin that supports oil and gas electrification and growing community demand.

The commission approved the plan in September 2024. It comprises local projects such as Oncor's, but it will also include ERCOT's first 765-kV transmission lines, with three import paths into the petroleum-rich basin. (See *Texas PUC Approves Permian Reliability Plan*.)

Outside ERCOT TEF Selections

The PUC accepted staff's recommendation to select six projects eligible for $387.1 million under the *Texas Energy Fund*'s Outside ERCOT Grant Program (OEGP) after their analysis of completed applications.

The *order* delegates authority to Executive Director Connie Corona to enter into grant agreements with the applicants, contingent upon a final review (*58492*).

The applications, all for reliability and resilience projects, belong to:

- Entergy: $199.7 million for transmission and distribution infrastructure hardening, pole replacement and flood-fortification projects.
- Sam Houston Electric Cooperative: $87 million to bolster its distribution system in hurricane-prone regions of its East Texas service territory by replacing wooden utility poles with high-strength, corrosion-resistant steel or ductile iron poles.
- East Texas Electric Cooperative: $51.5 million for undergrounding, pole upgrading, and transmission and distribution infrastructure projects.
- El Paso Electric: $43.5 million for continuous online monitoring, an energy storage system project, underground hardening in Downtown El Paso and restoration work at its Newman gas plant, among other initiatives.

The OEGP is one of four programs under the TEF and has been given $1 billion by Texas lawmakers to dispense to projects that make reliability and resilience improvements, modernize infrastructure, improve weatherization or address vegetation management outside of ERCOT's territory. The PUC selected the first four projects under the program in August, making them eligible for more than $240 million in grants. (See *Texas PUC Approves $240M in Energy Fund Grants*.)

Texas voters approved the TEF in November 2023 after legislation passed earlier in the year.

"The outside, or OEGP, piece of the bill maybe didn't get as much attention as the inside-ERCOT piece, but it's just as important," commission Chair Thomas Gleeson said. "I think it signals and shows that we're making significant progress towards achieving the goals of the entire bill."

PUC Chair Thomas Gleeson | *AdminMonitor*

Why This Matters

The approved transmission projects are meant to harden the grids and improve reliability in areas of West Texas and MISO that are seeing exponential load growth.

Entergy Transmission Project OK'd

The commission approved Entergy Texas' proposed SETEX Area Reliability Project, a 500-kV single-circuit transmission line in northeastern Texas that has drawn opposition from local landowners (*57648*).

The commissioners settled on the same 145-mile route that had been before them in the two previous open meetings that had the project on the agenda. The project has estimated costs between $1.33 billion and $1.52 billion. (See "SETEX Reliability Project," *Texas PUC Releases Rulemakings for Large Loads*.)

MISO identified the project as a baseline reliability project needed to comply with NERC's federal reliability standards and to address demand growth in the region.

In other actions, the PUC also:

- signed off on CenterPoint Energy's *settlement* with Houston and other cities to recover nearly $1.1 billion in system restoration costs eligible for recovery and securitization after Hurricane Beryl and other storms in 2024. The PUC stripped $2.2 million in legal expenses and consulting fees from the agreement, deferring them until CenterPoint's next ratemaking proceeding (*58028*).
- endorsed the suspension of $20.1 million in annual funding through 2030 for nuclear decommissioning costs related to Comanche Peak Power's ownership interest in the Comanche Peak Nuclear Power Plant's two units. The *order* also reduces the decommissioning costs to zero through 2030 (*58193*). ■

NRG Secures $562M Loan from Texas Energy Fund

By Tom Kleckner

Texas regulators have finalized a third loan agreement through the Texas Energy Fund's in-ERCOT program with NRG Energy for a 721-MW natural gas-fired plant near Baytown in Houston's dense petrochemical region.

Under the agreement, the Public Utility Commission of Texas will provide a 20-year loan of $562 million at 3% interest from the TEF. That will cover 60% of the project's costs, estimated at $936 million.

Construction has already begun on the facility at NRG's existing Cedar Bayou Generating Station, and the plant is expected to begin producing power by the summer of 2028. The project will be interconnected in the Houston Load Zone, the fifth-largest metropolitan area in the U.S.

"The Texas Energy Fund is bringing reliable, affordable power to ERCOT's fastest-growing regions," PUC Chair Thomas Gleeson said in a *statement*.

The TEF loan is NRG's second under the fund's in-ERCOT Generation Loan Program, one of four in the $10 billion program. The Houston-based company secured a $216 million loan in August to help build 456 MW of gas-fired capacity at another existing site in the region. (See *NRG Energy Secures $216M Loan from TEF*.)

Under the loan agreement, the facility must meet *minimum performance standards*. The PUC administers the TEF through a competitive application process and financial review of proposed projects.

NRG Energy has received a second loan from the Texas Energy Fund that will go to helping build a 721-MW gas-fired resource in Baytown, Texas. | *Baytown Visitor Information Center*

The three in-ERCOT loans disbursed so far will add 1,299 MW to the Texas grid. A commission spokesperson said 14 applications are still moving through the program's due diligence process, representing an additional 7,671 MW of capacity.

The $10 billion TEF, approved by voters in 2023, is designed to add 10 GW of gas-fired generation to the Texas grid. ■

Abbott Names Leader for Texas Nuclear Office

Jarred Shaffer's Appointment Draws Praise from Sector

By Tom Kleckner

AUSTIN, Texas — Texas nuclear industry experts are lauding Gov. Greg Abbott's recent appointment of Jarred Shaffer to lead the Texas Advanced Nuclear Office (TANO), which is responsible for funding mechanisms and regulatory support to accelerate nuclear energy deployment in the state.

The office was created by *House Bill 14*, signed into law by Abbott in June. It establishes the $350 million Texas Advanced Nuclear Development Fund, the nation's largest state fund for advanced nuclear energy, according to Texas officials. The fund will provide grants and funding for advanced nuclear reactor projects in Texas.

The bill also creates a nuclear permitting coordinator position that supports the development and deployment of advanced nuclear and innovative energy technologies.

"Jarred is a good choice who will be dedicated to an efficient and expedited process to get the state money out the door," former utility regulator Jimmy Glotfelty, who chaired the working group tasked with studying and planning the use of advanced nuclear in Texas, told *RTO Insider*.

Glotfelty's working group produced a *report* in 2024 that recommended setting up a state agency as the "tip of the spear" to provide a voice for the nuclear industry. (See *Texas Now Wants to be No. 1 in Nuclear Power*.)

"I think it's great that we're moving this forward very quickly, because until we get the pieces in place, we can't actually start giving away the money," said Casey Kelley, vice president of state government affairs in the South for Constellation. The company operates the largest fleet of nuclear plants in the U.S. and is a part owner of the 2.65-GW South Texas Project (STP) Electric Generating Station near Houston.

Vistra's 2.5-GW Comanche Peak Nuclear Power Plant is the only other nuclear facility in Texas. Comanche Peak and STP both have room for two additional reactors.

Former PUC Commissioner Jimmy Glotfelty (right), with Texas Nuclear Alliance President Reed Clay, during 2024's Texas Nuclear Summit. | © *RTO Insider*

Reed Clay, president of the Texas Nuclear Alliance, said Shaffer's appointment as TANO's inaugural director "marks another historic step in Texas's leadership on nuclear energy." He said the office will expand the state's clean energy portfolio, spur significant manufacturing investment, simplify the permitting process and ensure the U.S., not China, is exporting nuclear power technology to the developing world.

"Quickly executing on the mandate of House Bill 14 is necessary for the rapid deployment of new nuclear in the state," he said in an emailed statement to *RTO Insider*.

Clay called Shaffer's appointment further proof Texas is "leading a nuclear renaissance in the United States,"

"With strong leadership in place, it's time to build," Clay said, referring to Shaffer as a "seasoned energy policy expert."

Formerly a budget and policy adviser in the governor's office, Shaffer served as committee director for the Texas House Committee on State Affairs, a legislative liaison for the Texas Department of Transportation, and with the Texas Commission on Environmental Quality. He holds several bachelor's degrees from The University of Texas at Austin.

Abbott *said* Shaffer's expertise on energy issues "makes him the best fit to streamline the nuclear regulatory environment" and direct investments to spur the state's nuclear power industry.

"TANO and the Texas Advanced Nuclear Development Fund will increase Texas' investment in an all-of-the-above energy approach to solidify Texas as the world's energy hub," Abbott said.

"We do everything big in Texas," Glotfelty said during CERAWeek 2025 in March. "Success is steel in the ground, concrete in the ground, people working and building a plant. That is the end goal." (See "Nuclear Hub in Texas?" *Overheard at CERAWeek 2025*.) ■

IESO Seeking to Stay 'Two Steps Ahead' of Need

Scenario Planning No Longer an 'Ad Hoc' Tool

By Rich Heidorn Jr.

TORONTO — IESO is adopting more "proactive" planning processes as it embarks on its largest transmission expansion in two decades, ISO officials told attendees of the Ontario Energy Conference on Sept. 29.

Planners are working "to make sure that the transmission system stays two steps ahead of growth" with six bulk transmission plans and participation in 13 regional plans, said Beverly Nollert, director of transmission planning.

The ISO's *Pathways to Decarbonization* study in 2022 identified a need for up to $50 billion of new transmission. On Sept. 25, the ISO announced a third transmission line into Toronto. (See *Planners Pick $1.5B Underwater HVDC Line for Toronto's 'Third Supply'*.)

"This is more transmission planning that I've observed in my just over 20 years here in the sector," Nollert said.

"We're looking at: How do we make sure that we can supply demand from Windsor to Hamilton and into the [Greater Toronto Area] from the west, from the north and from the east? How are we addressing bottlenecks for electricity flow into Ottawa and other areas in Eastern Ontario, such as Belleville? How are we addressing bottlenecks in Northern Ontario? [We're also looking at,] how do we facilitate the connection of supply resources?"

During the low load growth years of the past, the province did not consider many large-scale transmission projects, Nollert said. "That was the reflection of the time, and it also [was] really in line with our mandate to ensure cost-effective reliability."

Speaking on the transmission panel were (from left): Robert Reinmuller, Hydro One; Beverly Nollert, IESO; Evan Yager, NextEra Energy Transmission, and John Vellone, BLG. | © *RTO Insider*

Now, she said, "we've started to shift our mindset to a more proactive planning approach. And what we've been starting to do is to look for future-ready investments that are required under several different pathways and scenarios.

"When we're comparing options, it's no longer just looking at … what do we need under a reference growth scenario, but also what might we need under a higher-growth scenario? And then with both of those insights, looking at … what's the right thing to do to future-proof the system? Because if we don't do that, it might be a lot more expensive to go back to accommodate the next tranche of growth."

As an example, Nollert cited the ISO's *Northern Ontario Connection Study*, which considered how to serve First Nations communities still supplied by diesel, as well as connect generating resources and support mining extraction in the Ring of Fire region.

Although the reference demand scenario found that immediate needs could be served by a single-circuit 230-kV line, "we have identified that it's actually more cost effective now to develop a double-circuit 230-kV transmission line to be able to future-proof the system and enable many different scenarios in the region," she said.

Chuck Farmer, IESO's executive vice president for power system development, said the ISO previously used planning scenarios "in a somewhat *ad hoc* way" in response to specific questions. Now it is using scenarios to "maintain optionality," he said.

"We don't commit [to investments] until we know [demand is real] so that we don't lock in costs going into the 2040s and 2050s that — if the signals are not there — will be difficult for ratepayers to manage."

The other half of "the planner's dilemma," Farmer said, is building too little infrastructure and becoming a limit on economic growth. "The sweet spot is a small, modest surplus. [That] is where you try to be. But the reality is, demand is uncertain; it will never play out quite the way you want."

Why This Matters

IESO is embarking on its largest transmission expansion in two decades.

Robert Reinmuller, Hydro One's vice president of transmission system planning and large accounts, said he welcomed the ISO's new philosophy.

"There was a time back in … 2022-2023 when my interaction with IESO drove me nuts," he said.

"We were saying, 'Well, the need is not quite there. We need another 15 MW. We got to wait.' And it happened to me couple of times [where] we sat on the bubble, and then the need materialized. And then the question I got from [IESO was]: 'Can you do this in three years?' No, I can't. I've been trying … for five years to get this done, but now I need to do it in two, three years, because the need suddenly tilted over that that bubble."

Injecting Competition

In July, the IESO released its transmitter registry of developers eligible for future competitive transmission procurements. The first solicitation is expected next year. (See *IESO Moving Forward with Competitive Tx Plans*.)

Evan Yager, of NextEra Energy Resources, said stakeholders "should give Bev and her team a bit of grace" over the time it has taken to implement competition.

"It's taken time, but we are asking an awful lot of her and the ISO to get this process up and running," he said.

He also said the ISO should learn from other grid operators, such as PJM, which has implemented a 120-day window on competitive transmission solicitations. Developers "have a 60-day window to pull together proposals and get those submitted. And on the flip side, PJM has a 60-day window to make decisions." ■

OEB Chief: Independent Adjudication, Aligned on Policy

By Rich Heidorn Jr.

TORONTO — The Ontario Energy Board will retain its independence in adjudications even as it embraces the province's directive for it to consider economic development in policymaking, the board's new chief executive said during a speech at the Ontario Energy Conference on Sept. 29.


Carolyn Calwell, CEO of the Ontario Energy Board | © *RTO Insider*

The OEB "is independent from, but aligned with, government," said Carolyn Calwell, who was *appointed* CEO of the board Sept. 8. "Our adjudicated decision-making is, and will remain, independent, but our policy development isn't necessarily so and, I would suggest, was never meant to be."

The OEB operates under the Ministry of Energy and Mines' annual letter of direction, which the ministry supplemented in June with its first-ever Integrated Energy Plan (IEP). The IEP contained multiple directives to the OEB and IESO. (See *Ontario Energy Plan Gives IESO Long 'To Do' List*.)

"The new model encourages people from across the OEB to work more closely together, breaking silos. It connects policy and adjudication," Calwell said. "It enables a better understanding of how different initiatives work together to achieve larger outcomes."

In his own speech, A.J. Goulding, president of London Economics International, said he trusts OEB and IESO to apply the economic growth criteria "thoughtfully." (See related story, *Goulding Hasn't Drunk the 'Energy Dominance' Kool-Aid*.)

"Directives should be used only as a last resort," he said.

Bill 40

The IEP prompted *Bill 40*, pending before the legislature, which would enshrine economic development as a central goal of the OEB and IESO. It also would give the board's CEO new authority to issue policies on procedures for hearings and determinations.

"Let me be clear: The OEB has always worked to support Ontario's economy and its people," Calwell said. "But the passage of Bill 40 would make economic growth part of the balance in our regulation of electricity. [It] is a critical priority, and a necessity for a secure Ontario, considering geopolitics today."

She cited the government's November 2023 *directive* to support new housing development. "Our team worked diligently last year to develop recommendations … related to getting houses built faster. It represented the OEB's best, independent and evidence-based advice. The government accepted our advice and moved to implementation. And as of a week ago, the *capacity allocation model* [for assigning infrastructure costs among developers, ratepayers and distribution companies] is in full force and effect."

Keeping the Planes in the Air

Calwell praised her staff for "keeping the planes in the air even as we change their major components."

"Coordination with the IESO is already at an all-time high … thanks to [IESO CEO] Lesley Gallinger and her team," Calwell said. "And given our joint work on enabling the Integrated Energy Plan, this integration, I think, will only increase over the fall."

In March 2023, the OEB said it would consider a "margin on payments" for distributed energy resources owned by customers or third parties, but the program "was too open ended" and infrequently used, Calwell said. After considering further consultation or a generic hearing to consider alternatives, she decided to exercise her authority under the Ontario Energy Board Act to amend or create codes.

"So as CEO, I'm working toward amending the Distribution System Code to establish a *margin on payment* incentive," she said.

"Amending the code is faster than another working group or a generic hearing, and it provides certainty for utilities. And by using a streamlined notice and comment process, we're moving quickly to address this well defined opportunity. We're creating a fair and predictable regulatory framework while we're being flexible and ensuring prudence. And it's a move that allows us to advance [at] the speed the energy sector needs," she added. "More efficiency, less red tape — this is one element of the OEB Integrated Energy Plan implementation directive. There are 18 others."

4 Workstreams

Calwell said the OEB is responding to the ministry's directives through four "workstreams":

- Expanding DERs through new business models: The OEB launched a benefit-cost analysis framework and non-wires alternative guidelines last year to provide regulatory toolkits for distributors who want to adopt DERs. By the end of the year, the board plans to issue an Ontario-wide capacity map, issue new code amendments to promote DER connections and submit its distribution system operator road map to the minister.
- Planning: The OEB is reviewing regional planning processes, the role of DERs in planning, scenario modeling and facilitating information sharing between the electricity and natural gas sectors. "Our goal is to build a common set of assumptions that help utilities effectively plan for an integrated energy future," Calwell said. The OEB and IESO will soon be issuing a discussion paper to prepare for an integrated planning forum next year.
- Utility remuneration: The OEB is benchmarking utility costs as a follow-up to its "*Distribution Sector Resilience and Responsiveness*" report to the ministry. "It's a foundation for advancing performance-based regulation, including incentives," she said. "The goal is to ensure the right data to support the next generation investment and ratemaking in Ontario."
- Streamlining procedures for connecting to gas and electric lines: "This work is critical to driving Ontario's growing economy," she said. "We'll allow homes to be built and occupied sooner, [and] businesses to ramp up more quickly so they can create jobs and economic opportunities." ■

Goulding Hasn't Drunk the 'Energy Dominance' Kool-Aid

By Rich Heidorn Jr.

TORONTO — The Ontario government's ambitious energy plan could prove costly to ratepayers if load growth stalls or new nuclear plants produce cost overruns, A.J. Goulding, president of London Economics International, told the Ontario Energy Conference in a keynote speech Sept. 29.

"I worry a bit when words like 'superpower' or 'energy dominance' are used," said Goulding, referring to the goals laid out in the Ministry of Energy and Mines' *Integrated Energy Plan* (IEP) in June. "They suggest a shift of focus from cost/benefit, risk and reward."

The IEP calls for expanding natural gas and nuclear generation, including four small modular nuclear reactors totaling 1,200 MW and a new 4,800-MW nuclear plant at the Bruce Nuclear Generating Station. The plan is premised on a projected 75% increase in electric demand by 2050. (See *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

Despite its name, Goulding said, the ministry's IEP is a "political document" rather than the investment blueprint that utilities file with regulators. "This is not a criticism. The IEP is a helpful statement of the government's intent and informs the deliberation of Ontario's quasi-independent agencies," said Goulding, whose speech was titled "Skating fast enough or over our skis?"

Goulding praised the IEP's "all-of-the-above" approach to generation as a way to balance affordability and environmental impact and said the province's proposed expansion of nuclear power "makes sense from a reliability and emissions perspective, not to mention jobs and land use."

A.J. Goulding, president of London Economics International | © *RTO Insider*

Why This Matters

Ontario is making a big bet on new nuclear generation and requiring IESO and the Ontario Energy Board to make economic development one of their organizational goals, which could undermine affordability.

Load Growth Projections

But he questioned the ministry's projection that load growth will increase by three-quarters — 3% per year — over the next 25 years.

"Looking at successive 25-year periods since 1960, we find the most recent that averaged 3% load growth ended in 1995," he said. "Only two individual years since 1997 have exceeded 3% lower growth.

"Per capita electricity consumption in Ontario peaked in 1988 and has fallen 36% since," he continued. "We keep finding new ways to not use electricity, and it's not clear that electrification will fully reverse these trends."

A recession, or the impact of the U.S. government's tariffs, could also dampen load growth. If growth falls short of projections, customers could face steep rate hikes to pay for infrastructure additions, he said.

New Nuclear Plants

Goulding also raised concern over Ontario's plan to build the first SMRs in the Group of Seven. The province hopes they will be a boon for economic development as other jurisdictions seek to tap its experience.

"While Ontario's bet on first-mover advantages on small modular nuclear reactors … may pay off, it also carries with it first-of-a-kind" risk, he said, citing research showing nuclear projects have averaged cost overruns of over 120%.

Although he acknowledged that "recent experience in Ontario has been more positive with refurbishment of legacy designs," he said it will take more than three SMRs to reach "N-of-a-kind" cost reductions.

"Ontario is not large enough to absorb sufficient reactors to reach that point on its own. Arguably, all of Canada may not be [large enough], making global partnerships critical," he said.

The magnitude of Ontario's planned spending on energy infrastructure leaves it vulnerable to "continuity risk" — the possibility that a large capital project is suspended following a change in government.

"Around the world, governments appear increasingly inclined to pivot from their predecessors' policies, regardless of underlying merit," he said. "This increases costs for projects that ultimately proceed and decreases investor confidence. Continuity risk is difficult to hedge. … and increases with project size. Large-scale nuclear investments could be particularly vulnerable to this risk."

Granular Additions

Goulding said scenario analysis and maintaining optionality are central to addressing forecast risk.

"New-build plans need to be tested against multiple outcomes. The optimal plan should perform well across several resources that can be added in more granular increments," he said. "An [Ontario Energy Board] process in which regulated entities detail IEP rate impacts and the extent of engagement with First Nations would provide both transparency and discipline as the province considers next steps."

He also called for increased use of demand response to reduce the need for peaking plants. "Now, the challenge with demand response," he joked, "is that it doesn't make for a nice ribbon cutting."

CCUS Utility

Goulding noted that the government's continued commitment to natural gas generation is tied to development of carbon capture, utilization and storage (CCUS). "If we believe carbon capture and storage requires scale, perhaps we need a carbon capture utility to catalyze CCUS investment," he said. "CCUS helps to legitimize the all-of-the-above strategy. It is also an area worthy of federal government support."

Conclusion

"We can best manage the risks in the IEP through appropriate time-limited consultation, thoughtful scenario analysis, diversification of ownership and resource type, expanding the role of demand response and creating a foundation for CCUS, while maintaining a focus on affordability," he concluded. "Policymakers need to take willingness to pay into account first as plans are being formulated, rather than after the fact, while also acknowledging that some rate increases are unavoidable." ■

Overheard at the 2025 Ontario Energy Conference

TORONTO — The Ontario government's efforts to align IESO and the Ontario Energy Board to make the province an energy "superpower" were the dominant theme at the 2025 Ontario Energy Conference on Sept. 29.


Ontario Premier Doug Ford | © RTO Insider

Premier Doug Ford, the first speaker at the conference, received a standing ovation after laying out his plan for using the province's energy sector to "build the strongest economy in the G7."

Ford's ambitions were spelled out in the Ministry of Energy and Mines' Integrated Energy Plan (IEP) in June, which called for expanding nuclear power and natural gas and making economic development a core mission of both IESO and the OEB. (See *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

The conference, sponsored by the Ontario Energy Association and the Association of Power Producers of Ontario (APPrO), attracted more than 450 attendees to the Marriott Downtown at CF Toronto Eaton Centre.

Outside the hotel, members of the Ontario Clean Air Alliance protested the government's support for gas-fired generation, calling for the province to instead triple wind and solar generation. They were joined by members of the Toronto East Residents for Renewable Energy, who rallied against a *proposal to expand* Ontario Power Generation's Portlands Gas Plant by 50 MW from its current 550 MW. They said the plant should be shuttered by 2030.

Inside the hotel, however, there was no overt opposition to the government's plan, although some speakers acknowledged the likelihood of rate increases and warned of the risks of building new nuclear generation.


IESO CEO Leslie Gallinger | © RTO Insider

IESO CEO Lesley Gallinger referred to the ministry's "bold and pragmatic vision."

"Economic growth, supporting population growth, supporting sovereignty and supporting First Nations reconciliation. I mean, this is a grand slam home run if we do this right," enthused Harry Taylor, CFO and interim CEO for Hydro One.


More than 450 people attended the 2025 Ontario Energy Conference. | © RTO Insider


Harry Taylor, interim CEO of Hydro One | © RTO Insider

In addition to a "relatively well-managed" transmission system and successful generation procurements, "for the first time in decades, we have also a vision," said Robert Reinmuller, Hydro One's vice president for transmission system planning and large accounts.

A.J. Goulding, president of London Economics International (LEI), gave the strongest critique of the IEP in his keynote address, raising questions about bullish load forecasts, the nuclear investment and the risk of policies being reversed after a change in government. (See related story, *Goulding Hasn't Drunk the 'Energy Dominance' Kool-Aid*.)

Province and Federal Government Aligned on Nuclear Expansion

Ford called for making Ontario "more competitive, more resilient and more self-reliant" to "build the strongest economy in the G7." Central to that vision, Ford said, was its "massive potential as an energy superpower."

The IEP developed by Energy Minister Stephen Lecce calls for the construction of four small modular reactors totaling 1,200 MW and the addition of up to 4,800 MW of nuclear capacity at the Bruce Nuclear Generating Station.

"I love the guy," Ford said of Lecce. "I talk to him every single day, four or five times."

Ford, a member of the Progressive Conservative Party, praised Liberal Party Prime Minister Mark Carney, who identified four SMRs planned at Ontario's Darlington nuclear power plant as one of the "nation-building" projects he said are needed to bolster the country's economy in response to U.S. President Donald Trump's escalating tariffs. (See *Ontario Environmentalists Slam New Nuclear Units*.)


André Bernier, Natural Resources Canada | © RTO Insider

"He's all in on large-scale nuclear [and] on the SMRs," Ford said. "He understands it. He gets it."

That comity was apparent later in a panel discussion featuring André Bernier, director general of Natural Resources Canada, the federal government agency responsible for energy and minerals, and Sam Oosterhoff, the province's associate minister of energy-intensive industries.

"I think we might be in danger, minister, of finishing each other's sentences," Bernier told Oosterhoff.

Later, in a keynote speech at the conference's evening gala, Lecce noted that though the provincial and federal governments are headed by different political parties, "we are on the same team in this moment. We're fighting for a similar cause. We have to stand up for our country, safeguard our workers against [the] great level of risk from the U.S., in China and Iraq.

"I like what I hear from the feds … moving with speed … nation building, regulatory reform, ending duplication [of environmental reviews, things] so important to the province's and the country's economy. But we now need them to do those things. We need an impact assessment law that does not take five years to assess projects [that] in the European Union can be done in 12 or 18 months. We need the feds to end duplication on critical projects."

Lecce also called for federal support to help meet the "massive, massive financial challenge" for needed infrastructure.

"We need a commitment on investment tax credits and the clean energy credits. … All of this [is] really important if we want to provide stability to the sector, which is why we've asked for a 50% commitment for the feds to help us derisk those investments and … protect ratepayers."

Lecce called it a "moment of pride" that Canada will build the first grid-scale SMR in the Group of Seven, "before the Brits or the French or the Japanese or the Americans."

"We need to get into the business of net new [nuclear]," Lecce said. "We can't just refurbish. We can't tweak. I think that incrementalism is really of the past. … There is no path to decarbonization; there's no path to economic growth; there's no path to … a domestic policy of jobs if we don't invest in new nuclear, embracing Canadian technology."

Colin Anderson, CEO of the Association of Power Producers of Ontario (foreground), and Vince Brescia, CEO of the Ontario Energy Association (on screen) open the 2025 Ontario Energy Conference. | © *RTO Insider*

DERs' Role

Numerous speakers cited the importance of distributed energy resources and demand response in helping meet a projected 75% increase in electricity demand by 2050.

Sheikh Nahyaan, executive vice president and chief operating officer for Toronto Hydro, said his company is "using non-wires solutions in a really meaningful way." It is seeking to acquire about 30 MW this year.

Philippe Dunsky, president of Dunsky Energy + Climate Advisors | © *RTO Insider*

"We're trying to forecast what's going to happen in 10 or 15 years," said Philippe Dunsky, president of Dunsky Energy + Climate Advisors. "DERs are really a risk mitigator — in addition to a cost reducer — for that uncertainty."

Market Design's 'Stress Test'

IESO's Gallinger said summer 2025 was a "stress test" for the grid operator's new market design, which launched May 1.

"It was a remarkable season for our system," Gallinger *said*. After a 2024 summer peak of 23,852 MW, multiple heat waves pushed the region past the 2024 peak seven times in 2025.

The day-ahead market — which became financially binding under the new nodal market — cleared more than 95% of demand. (See *Ontario Nodal Market Nearing 'Steady State' After Nearly 4 Months*.)

The summer "put in sharp focus the value and the strengths of Ontario's diverse supply mix, using our all-of-the-above approach to keep the system reliable, including new resources like the [250-MW/1,000-MWh] *Oneida Energy Storage* project that came online in May," Gallinger said. "We also saw important contributions from demand response. *Peak Perks* adjusted more than 270,000 thermostats to achieve an average load reduction of more than 200 MW in what has become the largest virtual power plant built in Canada.

"Commercial and industrial customers also provided significant reductions through the *Industrial Conservation Initiative* and the capacity auction. In total, consumers lowered demand by up to 7% over the peak periods."

Delivering on Promises, Controlling Costs of Transition

Numerous speakers talked about the challenge of winning public support for infrastructure investments that will be needed to meet growing demand.

"Don't kid ourselves about how much money this buildout — of essentially doubling the size of our electricity system — [will cost]," Oosterhoff said. "It's hundreds and hundreds of billions of dollars. You know, last year, I think the number I saw for generation and for transmission was $400 billion. I'm sure by now it's higher. ... That is a lot of money that people, ratepayers [and] taxpayers will have to pay."

But, he added, not building to meet need "is going to cost more than action. And the economic costs of not having that capacity for the next Volkswagen plant or the next LG plant, or the next tech company ... is something that we have to be very upfront with people about."

Hydro One's Taylor said utilities will have to execute "almost flawlessly." He said First Nations partnerships would be essential to building transmission across tribal lands.

And he said innovation is essential. "If we are still doing building ... the way we did 10 years ago, even five years ago, we're taking too long [and] it's costing too much," he said. "We've got to find a way to bring innovation to everything that we do so that we can tighten time frames and reduce capital expenditures."

Customers and policymakers are not the only ones who will be watching how utilities deliver, he said, noting that some of his company's largest investors are from Australia, Asia and Europe. "How do we compete across the globe for scarce capital?" he asked.

Hydro One's Reinmuller called for more certainty for investors' cost recovery and quicker decision-making.

"A lot of the things that [will be proposed from IESO's] bulk regional planning this year, we probably knew some of the answers two, three years ago," he said.

Natural Resources Canada's Bernier acknowledged that "when I think of the discipline of getting projects approved and built, getting through regulatory barriers ... our recent track record is maybe not all the way we want it to be." He praised the nuclear refurbishments in Ontario, saying they "have done a great job [keeping the] projects on budget."

Pluses and Minuses of Expanding Consultation

Moderating a panel on "Coordinated Integrated Planning for Growth," Dunsky asked whether a drive for increased coordination and agreement on common assumptions could concentrate risk. "In other words, if we're wrong, we're all working together, right?

André Bernier, director general of Natural Resources Canada (left), and Sam Oosterhoff, Ontario's associate minister of energy-intensive industries | © *RTO Insider*

"We are talk[ing] about launching a very complicated, exhaustive, coordinated process involving essentially the entire village," he continued. "How do we avoid this process becoming a kumbaya that slows us down instead of an alignment that speeds us up?"

Sheikh Nahyaan, Toronto Hydro | © *RTO Insider*

Toronto Hydro's Nahyaan said having multiple parties at the table creates transparency and ensures multiple perspectives.

"It reduces the risk of being wrong, because you're now having multiple parties and interested groups ... keeping you on your toes in terms of making sure that you are remaining agile."

LEI's Goulding weighed in on the question in his keynote speech. "Focused, time-limited consultation will lead to better plans," he said. "Risk management requires process. The worst mistakes I have made in my career have come from failure to consult and be deliberate, exacerbated by a belief in my own invincibility."

Municipalities Warming to Energy Development

Spencer Sandor, Association of Municipalities of Ontario | © *RTO Insider*

Spencer Sandor, senior adviser for the Association of Municipalities of Ontario (AMO), said his organization is helping its members evaluate potential energy projects' impacts and benefits.

"The average municipality has only six full-time employees, so that would be a clerk, a treasurer an administrative staff, and probably three guys driving the snowplow or a road grader, depending on what season it is," he said.

Over the last two years, AMO, IESO, the province and organizations including the Ontario Energy Association have helped municipalities develop resources, such as a procurement tool kit, a guide "to help both municipalities and developers understand how to talk the same language to each other," he said.

At AMO's annual conference in August, Sandor said, representatives from multiple municipalities approached the IESO booth "saying, 'How do I get one of these projects?'"

Sandor said municipalities are looking for impartial sources of information to address their concerns. "If, say, it's a battery storage project, they are inevitably going to say, 'Is this thing going to catch fire?'

"There's kind of two responses to that question. One is, 'Don't worry, it won't catch fire, trust me.' And the other one is … 'You're right, they have caught fire in the past. The technology has evolved. … Here are several resources from the Fire Chiefs Association, from the Energy Storage Association, from Hydro One, that talk about how the technology has improved, and more importantly, what we can do as a fire service to respond to that.'

"I'll give you one guess which one of those answers is more likely to get a municipal support resolution."

During IESO's first long-term solicitation, "the story that was being told [was that] these municipalities are saying 'no,'" Sandor said.

"Coming out of that process, IESO was still able to get contracts for more capacity than they targeted," he said. "Now that municipalities do have more expertise, the dialogs are a lot more constructive."

Gas not Going Away

Minister Lecce cited the province's *Natural Gas Policy Statement*, calling it "the ultimate insurance program" for the power sector.

Ontario Energy Minister Stephen Lecce (left) and Carla Nell, IESO's executive VP of corporate relations, engagement and strategy (right), with IESO colleagues Saiyma Monnan and Jamie Jang. | *Minister Stephen Lecce*

Lecce said the Ontario grid will reach a target of 99% non-emitting generation by 2050, largely through more hydro and nuclear power.

"Renewables will play a critical role in this space. … But we're not going to … negate the role of having [gas] on the option lists. That is just ideological insanity, and that's the type of policy, frankly, that led to Ontario having the highest energy cost on the continent."

Brian Johnson, Enbridge | *© RTO Insider*

A year or two ago, "the world's messaging was, 'We're getting out of fossil fuels,'" said Brian Johnson, general manager and senior vice president of Enbridge.

On the coldest day this year, he said, the gas system produced 4.9 times the energy of all other sources combined. "So, I think we're getting, hopefully, back to some practicality."

Elexicon at the 'Tip of the Spear'

Elexicon Energy CEO Amanda Klein | *© RTO Insider*

Amanda Klein, CEO of electric distribution company *Elexicon Energy*, said customer demand growth in the Greater Toronto Area East is "nothing short of bananas," with a projected customer increase of nearly 20%.

"That's a whole SkyDome full of new customers for a utility that fills about five SkyDomes today," she said, referring to the Toronto Blue Jays' stadium (now called the Rogers Centre).

While other utilities are projecting peak demand by 2060, "we're going to have most of that happening in the next decade, rather than the next 25 years," she said.

"So what I see at Elexicon is that we're going to be, for the industry, really the tip of the spear in terms of population and economic growth in Ontario that we're seeing.

"We've got a capital program that's doubled in recent years. It's about to double again." ■

— Rich Heidorn Jr.

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ISO-NE Publishes Draft 2026 Work Plan

By Jon Lamson

Capacity auction alterations, a new asset condition reviewer role, parallel transmission planning efforts, new reserve products, Pay-for-Performance changes and interconnection modifications are all likely to be on the docket for ISO-NE in 2026.

The RTO's draft 2026 annual *work plan*, published in advance of the NEPOOL Participants Committee's meeting Oct. 9, includes continued work on several major ongoing projects and outlines potential new initiatives related to dynamic operating reserves, PFP adjustments and surplus interconnection service.

The Capacity Auction Reform (CAR) project will continue to be the RTO's main market development focus. The second phase of CAR, which is scheduled to run throughout 2026, will focus on overhauling the RTO's capacity accreditation methodology and splitting annual capacity commitment periods into distinct summer and winter seasons. (See *ISO-NE Kicks off Talks on Accreditation, Seasonal Capacity Changes*.)

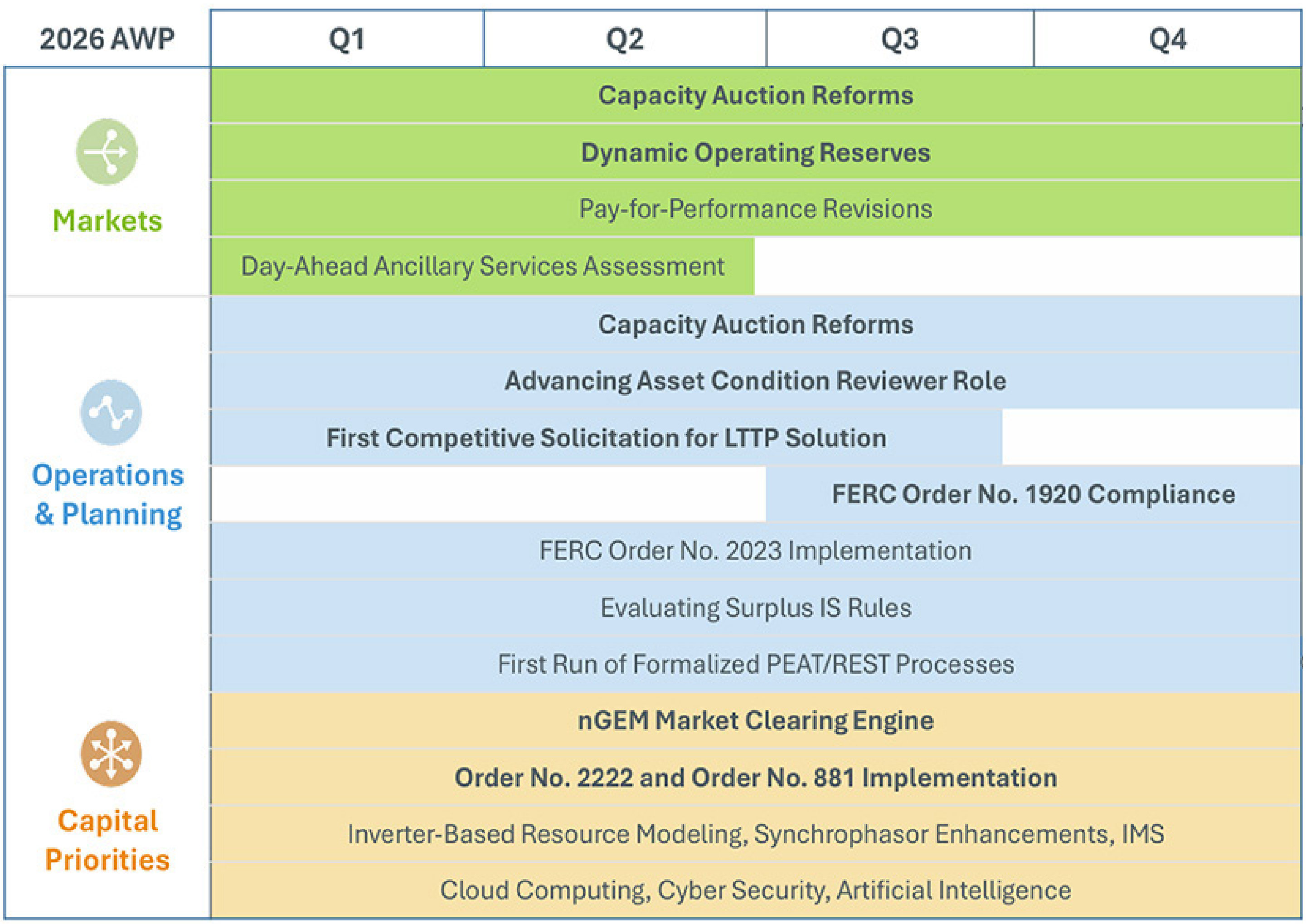
ISO-NE is planning to seek technical committee votes in November on the first phase of the project, centered around the transition to a prompt market, followed by a PC vote in December. (See *Stakeholders Mixed on ISO-NE Prompt Capacity Market Proposal*.)

Other projects for 2026 include ISO-NE's effort to stand up a new "asset condition reviewer" role. The role is intended to provide increased transparency around pooled costs associated with upgrades to aging and degrading transmission infrastructure, which have ballooned in recent years. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

Why This Matters

A significant portion of ISO-NE's work in 2026 will focus on preparing the region's grid for increasing intermittent renewable generation and growing and more variable demand for electricity.

As ISO-NE works to develop its in-house review capabilities over the next year, "the ISO plans to use a consultant to begin reviewing some [asset condition] proposals in an interim phase and facilitate stakeholder review and discussion of the consultant's feedback," the RTO wrote in its work plan.



ISO-NE's estimated stakeholder discussion timing for 2026 | *ISO-NE*

Transmission Planning

Also in 2026, ISO-NE plans to evaluate and select a preferred transmission solution for the first Longer-Term Transmission Planning (LTTP) solicitation, which is intended to increase transmission capacity in Maine and help interconnect new onshore wind generation in the state. (See *ISO-NE Releases Longer-term Transmission Planning RFP*.)

According to ISO-NE spokesperson Randy Burlingame, the RTO received six qualified responses prior to the Sept. 30 deadline. Burlingame declined to comment which companies submitted proposals, but said ISO-NE will publish summaries of the proposals within 60 days.

ISO-NE wrote in the work plan that it plans to select a preferred solution "as early as September 2026."

"Upon completing, reviewing and adjusting for any lessons learned from the 2025 cycle, the LTTP process could then proceed with a subsequent cycle, which would seek stakeholder input," the RTO added.

In the third quarter of 2026, ISO-NE plans to begin work to comply with FERC Order 1920, which establishes long-term planning requirements for grid operators. In February, FERC accepted ISO-NE's request to push back the compliance deadline for the order by two years, extending it to June 2027. The RTO has said the delay will enable it to "implement and gain experience from conducting the first LTTP" request for proposals.

"While New England's new LTTP framework accepted by FERC in July 2024 went far in complying with [Order 1920], notable differences must be addressed," ISO-NE noted.

The RTO said Order 1920 compliance discussions will likely include a focus on "further including [grid-enhancing technologies] into transmission planning assessments," along with the development of a process for right-sizing asset condition upgrades "as a way to address long-term needs."

Dynamic Operating Reserves

To prepare the system for increasing variability in both generation and demand, ISO-NE "is assessing and commencing development of dynamic, operating reserve demand curves for incremental quantities of existing real-time reserve products (10- and 30-minute reserves), in amounts that vary during the operating day based on the system's near-term potential ramping needs," it wrote.

The RTO is also considering adding a 60- or 90-minute reserve product, which could include "dynamically determined demand quantities," to prepare the system for "unanticipated supply and demand changes."

In a *memo* published in March, ISO-NE wrote that, to address increasing uncertainty and ramping requirements, it plans to develop "a dynamic, real-time probabilistic forecast of the system's energy ramping needs," which could inform these new reserve products. (See "Flexible Response Services," *ISO-NE Gives Updates on Prompt, Seasonal Capacity Market Changes*.)

The RTO plans to begin stakeholder discussions on these potential changes in the fourth quarter of 2026.

Pay-for-Performance

ISO-NE also wrote that changes may be needed to its PFP rules following a recent New England Power Generators Association (NEPGA) complaint to FERC about "serious flaws" in the construct's design.

In response to the complaint, ISO-NE has said it is open to capping the PFP balancing ratio but opposed NEPGA's proposed changes to the stop-loss mechanism. (See *ISO-NE Open to PFP Changes Following NEPGA Complaint*.)

"The ISO may assess and discuss with stakeholders possible cost-allocation related revisions to the stop-loss mechanism and balancing ratio, depending on FERC action on NEPGA's filing," ISO-NE wrote in its work plan.

Surplus Interconnection Service

Prior to the publication of the work plan, some stakeholders pushed ISO-NE to pursue updates to surplus interconnection service rules, arguing that the RTO should allow increased flexibility for interconnecting resources that are willing to accept limits based on the existing capacity resources at an interconnection point. (See *Stakeholder Forum: Surplus Interconnection Can Maximize Capacity in ISO-NE*.)

ISO-NE wrote that it plans to initiate discussions with stakeholders in the first quarter of 2026 "to identify the objectives, issues and scenarios driving stakeholders' inquiries around existing and future access and use of assigned interconnection service rules."

Following initial discussions, the RTO plans to "conduct a gap analysis of the use cases against the existing interconnection rules to determine the scope of potential solutions," which would inform additional stakeholder discussions on potential rule changes.

ISO-NE also is scheduled to complete its first cluster interconnection study under transitional Order 2023 rules in August 2026. The next cluster study will begin in October 2026.

Other Initiatives

The work plan also includes initiatives intended to improve ISO-NE's modeling of inverter-based resources, boost cybersecurity and deploy a new market clearing platform.

The RTO also plans to publish a report on the performance of its new day-ahead ancillary services market that will include "any potential recommendations for enhancements."

ISO-NE will discuss the draft work plan with NEPOOL members at the PC meeting in West Hartford, Conn., on Oct. 9. ■

Gas Industry Sees Political Opportunity in New England

By Jon Lamson

Why This Matters

As demand grows, the role of new natural gas infrastructure in New England appears poised to be a major point of contention between business groups and climate advocates.

MARLBOROUGH, Mass. — Speaking at an industry conference Sept. 30, representatives of major gas pipeline companies said they are optimistic that political shifts at the federal and state levels will create opportunities for gas infrastructure expansion in New England.

Panelists at the Northeast Energy and Commerce Association's annual Fuels Conference emphasized the importance of reducing the region's gas constraints to alleviate affordability and reliability concerns, while downplaying climate concerns about long-term reliance on natural gas.

"After decades of disagreement, a lot of key states are coming around, and a lot of it centers around the need for electric generation," said Rick Smead, managing director at RBN Energy. He added that data center demand growth in the Boston area has increased the urgency to address gas constraints.

Brooke Thomson, CEO of the Associated Industries of Massachusetts (AIM), the largest business association in the state, said she has "seen a shift" in the political acceptance of natural gas.

"A lot of the change that has come out of the shift in federal administration is trickling down to the local level," Thomson said, adding that Massachusetts Gov. Maura Healey (D) has emphasized that "everything's on the table, including natural gas."

She said the conversation around gas in the state has shifted significantly since the Biden administration, when Massachusetts lawmakers sought to ban new natural gas hookups and succeeded in passing a pilot program allowing 10 municipalities to ban gas connections for most new buildings.

From left: Rob Mosher, Interstate Natural Gas Association of America; Mike Dirrane, Enbridge; Christopher Stutz, Iroquois Gas; Natalie Cooper Grindle, Williams; Alana Daly, Northeast Gas Association | © *RTO Insider*

Bill Ryan, chairman of Pilgrim Strategies, a lobbying firm whose largest client is Enbridge, said Healey "has almost gone out of her way to talk about the reality of natural gas in the current energy mix and the future energy mix."

While the industry was on the defensive in Massachusetts under the Biden administration, "I think we're in a different arc right now," with political leaders in the state "singing a different tune," Ryan said.

Speakers at the event stressed that the gas industry should double down on their efforts to drive the narrative around gas in the state.

"We've really made some gains in having people better understand the impact of natural gas," said Mike Dirrane, director of Northeast marketing at Enbridge. "We've seen a change in the narrative, even in the media."

"I think we need to be even more aggressive in pointing out the benefits of the natural gas industry," he added.

Earlier in September, Enbridge *announced* a $300 million project to expand the capacity of its Algonquin pipeline into Massachusetts by about 75,000 Dth/d. Dirrane said the company has reached agreements with seven utilities in New England to support the expansion, which Enbridge expects to be completed in 2029. The project would not require any new compression, he added.

The project would be a relatively small expansion of the pipeline, which has a peak day *capacity* of over 3 million Dth. It appears to be a significantly scaled-back version of Enbridge's 2023 proposal to increase Algonquin's capacity to Massachusetts by 250,000 Dth/d. (See *Enbridge Announces Project to Increase Northeast Pipeline Capacity*.)

Dirrane said the project will meet "some of the critical needs right now" but speculated that a subsequent project may be necessary "to meet additional needs further down the road." He said Enbridge has met with "all of the administration officials in New England" and has "had some great dialog and really good education on the benefits of natural gas and its impact on affordability."

The project will likely be met with significant resistance from climate organizations in the state, which have opposed all efforts to expand gas capacity into the region. Environmentalists argue that increasing the long-term reliance on natural gas is not compatible with reaching net-zero emissions by 2050; methane is a potent near-term greenhouse gas and a *key contributor* to manmade climate change.

Smead applauded the effort to increase pipeline capacity to the Northeast. While the Algonquin expansion is "not a huge project," he expressed his hope that "there's going to be more of these that keep ramping up capacity, rather than a big monster that gets in all the papers."

He stressed that, despite changing political attitudes around gas expansion, key barriers to addressing New England's gas constraints remain.

He highlighted a pair of large pipeline projects to the region that were shelved during President Donald Trump's first term: Kinder Morgan's Northeast Energy Direct project and Enbridge's Access Northeast project.

"The reason stuff didn't get built in New England was because people didn't want to pay for it, not because environmentalists lay down in the right of way," Smead said.

The financing challenges for new pipelines in New England are often attributed to the fact that gas utilities have been reluctant to sign long-term contracts to support major projects; electric utilities are not allowed to use ratepayer funds for pipeline contracts; and gas generators typically do not sign long-term firm supply contracts. (See *New Pipelines Unlikely for New England, Experts Say*.)

While New England generators often struggle to access pipeline gas during the coldest days of the year, gas generation in ISO-NE has increased steadily in recent years, hitting its all-time high in 2024 amid reduced electricity imports from Canada. (See *New England Gas Generation Hit a Record High in 2024*.)

"It's not necessarily in the interest of the generators to pay for it if they make their money off of volatility," Smead added.

The Role of LNG

Multiple speakers emphasized the importance of the Everett LNG import terminal to the region and said there may not be a single solution to replace the facility when its contracts with Massachusetts gas utilities expire in 2030.

When approving the contracts, the Massachusetts Department of Public Utilities directed the utilities to develop a plan to reduce their reliance on the import terminal. (See *Massachusetts DPU Approves Everett LNG Contracts*.)

Everett, which is north of Boston, supports direct injection into the gas network and the dispatch of LNG trucks to other points on the system.

Jeff Tounge, development lead at Cashman Preload Cryogenics, outlined the company's proposal to build an LNG storage tank in Northern New England that could supply 200,000 Dth of gas for winter reliability and inject enough gas to supply a 1,300-MW gas plant for 10 days during peak demand.

He said the project would provide reliability benefits during cold winter periods and that Cashman is seeking long-term utility contracts for the project.

Charlie Riedl, executive director for the Center for Liquefied Natural Gas, said he sees an important role for both LNG infrastructure and additional pipeline capacity.

"What the Northeast really needs is additional pipeline capacity to complement LNG," Riedl said, adding that "pipelines are the most cost-effective way to meet growing demand."

Emissions Limits

Also at the meeting, several speakers said they hope Massachusetts will re-evaluate its legally binding decarbonization targets, which require the state to cut its emissions by 50% by 2030 and at least 85% by 2050, relative to 1990 levels.

"There should be a real hard look at going back and providing some flexibility there" to account for "what's potentially feasible right now," AIM's Thomson said.

"I think it's possible that the House does this," she added. "Do I think the Senate would do this? I don't think they would, but I hope they consider it." ■

Court Dismisses Claims of NextEra Antitrust Violations to Block NECEC

By Jon Lamson

A U.S. district court judge in Massachusetts has granted NextEra Energy's motion to dismiss claims the company violated federal and state antitrust laws in its efforts to block the New England Clean Energy Connect (NECEC) transmission project.

In a September ruling on an Avangrid lawsuit alleging that NextEra undertook an "anticompetitive scheme" to block the NECEC line, District Judge Mark Mastroianni found that Avangrid failed to prove that NextEra exercised monopoly power.

NECEC is an under-construction 1,200-MW transmission line connecting Québec and New England. The project, which was selected in a 2018 procurement by Massachusetts, is intended to facilitate large-scale baseload imports of power into ISO-NE.

Avangrid's lawsuit, issued in November 2024, alleges that NextEra "has reaped hundreds of millions" from its efforts to stop or delay the NECEC line. Avangrid wrote that it has suffered at least $350 million in damages. (See *Avangrid Sues NextEra over 'Scorched-earth Scheme' to Stop NECEC*.)

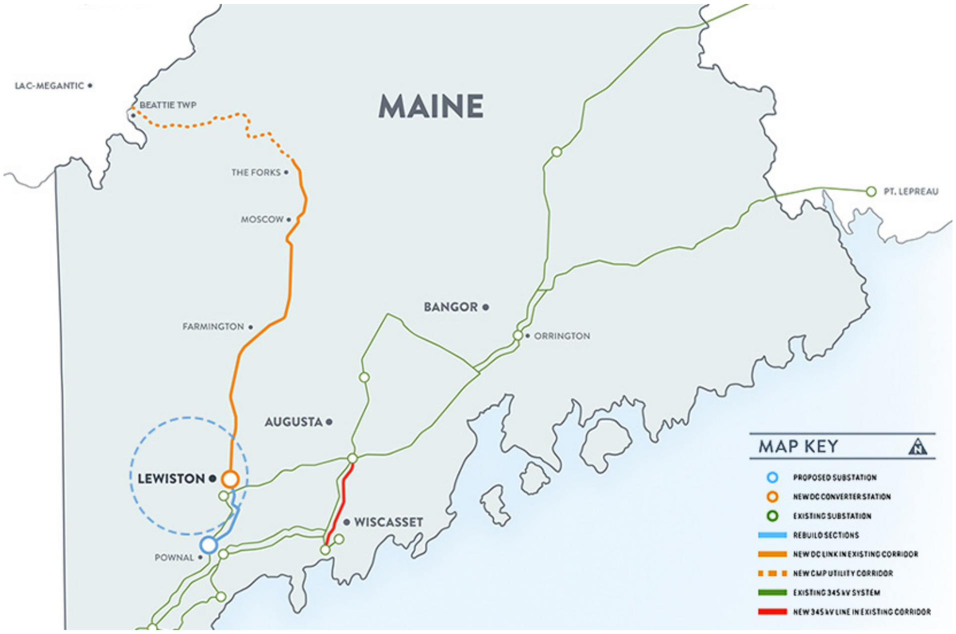
NextEra, which owns over 2,700 MW of generation capacity in New England — including the Seabrook Station nuclear plant in New Hampshire — opposed NECEC in regulatory proceedings in Maine and Massachusetts, funded a pair of ballot initiatives in Maine to block the project, and clashed with Avangrid over the upgrade of a near-capacity breaker at Seabrook that was required to interconnect NECEC.

The company's opposition to NECEC appears to have successfully delayed its development for multiple years. While the referenda on the line ultimately were struck down in court and NextEra-funded political groups were fined for multiple campaign finance violations, the second referendum caused a two-year pause in construction on the line.

Avangrid initially expected to complete the project in late 2022; it remains in the *late stages* of construction.

NextEra filed a motion to dismiss Avangrid's lawsuit in January, arguing that "all of the federal and state antitrust claims should be dismissed for the failure to properly plead monopoly power in a relevant market."

In his Sept. 22 ruling, Mastroianni found that Avangrid failed to demonstrate that NextEra had monopoly power in New England.



NECEC project map | *Avangrid*

Why This Matters

The multiyear delay of NECEC has likely led to higher wholesale power prices across New England.

"Avangrid has not identified NextEra's percentage of market share in the relevant markets or even alleged, more generally, that NextEra possessed a predominant share" of ISO-NE's markets, Mastroianni wrote.

"While Avangrid has alleged interconnection of NECEC was likely to lower NextEra's revenue in the relevant markets, there are no facts from which the court could plausibly conclude NextEra was able to set above-market prices in marketplaces operated by ISO-NE," he added.

Regarding Avangrid's claim that NextEra resisted replacing the breaker at Seabrook to prevent new participants from entering the market, Mastroianni wrote that "a bottleneck that limits entry into the relevant market, on its own, is insufficient evidence of monopoly power." (See *D.C. Circuit Affirms FERC Ruling on Seabrook Circuit Breaker Dispute*.)

"There must also be a basis for finding the defendant can 'profitably set prices well above its costs' or would gain such power through the challenged conduct," he added.

"In the absence of sufficient allegations to support a finding that NextEra was able to charge supracompetitive prices within the relevant markets, or was likely to become able to do so if it could delay or prevent NECEC from entering those markets, the court cannot find NextEra's multi-pronged campaign to delay or derail NECEC violated Section 2 of the Sherman Act," Mastroianni concluded.

He wrote that the court intends to issue a separate order on additional claims made by Avangrid alleging unjust enrichment, intentional interference with a contract and unfair business practices. ■

MISO Eschews Latest Data to Limit CONE Increase for 2026

RTO to Use New Reference Technology Beginning in 2027 for Capacity Auction Caps

By Amanda Durish Cook

Inflation and higher borrowing costs pushed MISO's cost of new entry up by about 5% heading into the 2026/27 planning year, but stakeholders are questioning the RTO's use of 2020 data in calculations in order to keep prices lower.

This year, MISO's cost of new entry (CONE) varies from $142,970/MW-year in Missouri's Zone 5 to $123,250/MW-year in Mississippi's Zone 10. On average, the 2026/27 CONE is almost $359/MW-day, higher than the roughly $341/MW-day used in the 2025/26 capacity auction and the $330/MW-day used during the 2024/25 planning year.

CONE is the annualized, capital cost of constructing a power plant. In MISO's case, the RTO calculates values per local resource zone and uses them to establish price caps in its capacity market.

MISO used data from the U.S. Energy Information Administration's (EIA) 2020 Capital Costs Report for its hypothetical, advanced combustion turbine example instead of relying on the agency's new figures from the 2024 report.

The RTO said it wanted to stick with its usual, theoretical 240-MW simple cycle plant instead of the EIA's new norm, which would more than double the size of the example plant. The RTO upped the cost of the 2020 plant to reflect inflation.

Joshua Schabla, senior market design economist at MISO, said the RTO didn't meaningfully alter its CONE calculations this year but would probably change them by the time it crunches numbers again in 2026.

MISO plans to change the reference technology used for its power plant example for the 2027/28 planning year. Schabla said MISO plans to begin discussing its new CONE resource reference beginning in November. (See *Transition Spurs Power Producers to Ask for Fresh Look at MISO Cost of New Entry*.)

Some stakeholders attending an Oct. 1 Resource Adequacy Subcommittee meeting said MISO should have used more up-to-date information to inform CONE. By not upping its reference prices to reflect the true state of the industry, MISO could risk its reliability, they said.

Why This Matters

Some stakeholders were apprehensive about MISO's decision to use 2020 data instead of 2024 data in its 2026/27 cost of new entry values. MISO said it relied on years-old information to keep the prices consistent year over year.

Representing the Coalition of Midwest Power Producers, Travis Stewart expressed concern that MISO's reliance on

Continued on page 39

ZONE	PY 2026/27 CONE $*(MW*yr)-1	PY 2025/26 CONE $*(MW*yr)-1	PY 2024/25 CONE $*(MW*yr)-1
LRZ 1	$ 134,160	$127,720	$124,541
LRZ 2	$ 131,310	$125,090	$121,731
LRZ 3	$ 127,330	$121,220	$117,600
LRZ 4	$ 132,380	$126,040	$121,434
LRZ 5	$ 142,970	$136,170	$131,725
LRZ 6	$ 130,710	$124,360	$120,340
LRZ 7	$ 137,510	$130,930	$127,135
LRZ 8	$ 125,070	$118,960	$113,810
LRZ 9	$ 123,890	$117,710	$112,804
LRZ10	$ 123,250	$117,330	$112,263

MISO CONE values compared to those of the last two planning years | *MISO*

MISO IMM Recommends Changes to Handling of Midwest-South Tx Constraint

MISO's Independent Market Monitor has called for the RTO to change how it manages its Midwest-South transfer limit in ways he contends will open line capacity and reduce costs for Midwest market participants.

IMM David Patton asked MISO to create more steps on the limit's transmission constraint demand curves to use more megawatt space on the transmission path and create headroom for deviations.

At a Sept. 30 MISO Market Subcommittee meeting, Patton said the Midwest-South limit has been binding more frequently since 2022 and contributed to $41 million in congestion over summer 2025, a 121% increase over 2024.

MISO IMM David Patton | © RTO Insider

He said the regional transfer constraint has been used more in recent years due to solar additions in the South, a long-lived drought in Manitoba that has the Midwest exporting more power than usual and a drop in natural gas prices that has made MISO South's plentiful gas generation more attractive.

Patton said reformulated demand curves on the transfer limit would allow greater energy transfer capability, increased use of MISO South generation and reduced costs to loads in MISO Midwest. He said adjusted curves could allow the RTO to tap into more than 200 MW on average in the South and increase flows by 50-60 MW.

Patton contended that adopting his demand curve recommendations would have reduced Midwest average energy prices by $3.48/MWh and driven down the region's market costs by $515 million just over summer 2025.

Why This Matters

MISO's IMM says his recommendation could save Midwest market participants money by opening up more capacity on the Midwest-South constraint to tap cheaper generation.

Patton said also that he's long advocated MISO renegotiating its contracts with SPP and other neighbors to stipulate how MISO is allowed to use the transfer limit. He said because the transfer limit is a "contractual constraint that does not reflect any physical limits," MISO should work to get more out of it. ■

— Amanda Durish Cook

MISO Eschews Latest Data to Limit CONE Increase for 2026

Continued from page 38

2020 data is "inconsistent with market signals that we're hoping to create."

"New gas turbines are two to three times more expensive than they were a year ago. That information should report back to the market. The objectivity of this is important," Stewart said. He added that he worried that consumer advocates could draw on MISO CONE values to argue against cost recovery proposals for new generation in public service commission proceedings, since prices would not match.

Pelican Power's Tia Elliott said MISO was possibly setting itself up for a "wide spread" between it and other grid operators.

However, Anna Sommer, principal at the Energy Futures Group, said she appreciated MISO being cautious before making "major" changes to CONE. She said because MISO's capacity auction is only a prompt-year auction and most member utilities are vertically integrated, the capacity auction should not be considered a source for long-term planning signals.

Schabla said MISO didn't want to impose "supply shocks" on the market if they're not going to last, adding that the RTO wanted to avoid publishing high prices only to have to downgrade them in ensuing years. He said there have been questions over the legality and the longevity of the tariffs imposed by the Trump administration. Had MISO incorporated all variables, CONE might have risen by a factor of two or three, Schabla said.

"It's a little too early for us to make a decision like that and factor that into the price caps," he said.

Werner Roth, economist with the Public Utility Commission of Texas, said had MISO produced numbers as much as three times higher than in 2024, governors of MISO states would have reacted poorly and made PJM's continuing fallout over record-high capacity prices look like a "pillow fight."

Schabla said he thought wildly volatile numbers year-over-year would be worse than not drawing on the freshest data available.

"Stability matters," he said. ■

Stakeholders Demand Answers on Repeat MISO South Capacity Advisories

By Amanda Durish Cook

Entergy's River Bend Nuclear Station in Louisiana | *Entergy*

Stakeholders told MISO they need a better explanation of the every-other-day capacity advisories issued for MISO South, which have become customary since the beginning of summer.

Jim Dauphinais, an attorney for multiple industrial end-use customers, commented that there's been an "extraordinary" number of capacity advisories in MISO South in recent months.

"We don't know if it's a change in MISO practices or a change in resource availability," Dauphinais said at a Resource Adequacy Subcommittee meeting Oct. 1. He asked MISO staff to speak on its raft of declarations in the South.

"It makes people ambivalent. … I don't know if that's too strong of a word. The situational awareness goes down because they are happening so frequently," Dauphinais said.

Mississippi Public Service Commission consultant Bill Booth agreed that the regularity of the alerts has made them easier to ignore.

"An alert is useful if there are instructions following it. We're not sure what to do with these," Booth said.

MISO Resource Adequacy Director Neil Shah said one of the drivers behind the advisories is a larger number of outages in the South. Beyond that, he said his colleagues would be better equipped to speak on the continual advisories at an upcoming stakeholder meeting.

The RTO has extended its steady stream of capacity advisories from summer into September, *issuing* 15 capacity advisories over the month, with a few including MISO Midwest.

Why This Matters

Stakeholders say the onslaught of capacity advisories since the beginning of summer has made them more likely to ignore them.

At MISO's quarterly Board Week in September, Executive Director of System Operations Jessica Lucas said the RTO is trying to indicate periods of elevated reliability risk in the South so that no one is caught off guard by potential emergency orders. (See *MISO Recounts Tough Summer; Monitor Praises Lack of Emergencies* and *MISO on Track to Wrap Summer with 122-GW Peak, Addresses Frequent South Advisories*.)

Stakeholders have speculated that advisories are the direct outcome of the RTO's load-shed orders in Greater New Orleans during Memorial Day weekend. (See *MISO Says Public Communication Needs Work After NOLA Load Shed*.)

Public Utility Commission of Texas economist Werner Roth told Shah to expect similar questioning from the Entergy Regional State Committee at its Oct. 7 meeting.

"We're going to expect some more clarity around this. We are curious to get more of a dive in this," Roth said.

Pelican Power's Tia Elliott said she's been fielding questions about the advisories.

"Is MISO being more conservative because of what happened in May? More information from MISO would be useful," she said.

WEC Energy Group's Chris Plante also said his coworkers have been approaching him for answers.

"Was there a change to operational procedures? And if there was, would that potentially extend to MISO North? Those are questions I don't have answers for," Plante said.

Minnesota Power's Tom Butz asked whether the frequent advisories would affect the resource adequacy hours MISO uses in its availability-based accreditation or have an influence on how it plans to divvy up the planning resource margin requirement among its load-serving entities. (See *Stakeholders Question MISO Plan to Reassign LSEs' MW Duties Based on Risky Periods*.)

"All fair comments and questions. I hear you guys loud and clear," Shah said. He promised to take the concerns to fellow staff members and have them address the advisories publicly. ■

D.C. Circuit Vacates FERC Cancellation of Reactive Power Compensation in MISO

Order 904 Remains in Effect

By Amanda Durish Cook

The D.C. Circuit Court of Appeals on Sept. 26 vacated a FERC order allowing MISO to end reactive power compensation, though the decision has no bearing on the nationwide discontinuation of payments for reactive power in Order 904 (*23-1134*).

The court said that when FERC greenlit MISO's move to eradicate reactive power revenues, it failed to fully consider the generators' short-term financial health. The court remanded the matter back to FERC for a fresh decision.

MISO in 2023 *ended* reactive power charges in transmission rates along with cost-based compensation for generators' production of reactive power (ER23-523). (See *FERC Ends MISO Compensation for Reactive Power Supply*.) Since then, the RTO has treated reactive power within the standard power factor range — which plays a hand in stabilizing voltage levels across the grid — as an incidental product of generation and transmission and doesn't facilitate sales.

Several generators objected and argued that MISO's immediate removal would disturb their investment-backed interests. The D.C. Circuit agreed, saying FERC neglected to "consider important aspects of the problem before it."

"The generators explained that they had incurred significant debt and contractual obligations relying on MISO's longstanding practice of allowing generators to recover cost-based compensation for reactive power. In approving MISO's proposal to eliminate that compensation, FERC failed to explain why these financial concerns were unjustified, entitled to no weight or outweighed by other considerations," the court said.

In late 2024, FERC issued Order 904, prohibiting transmission providers from including charges in their rates to compensate generators for reactive power within the deadband range (0.95 leading to 0.95 lagging). The commission decided the normal range of reactive power would simply be a condition of interconnection (*RM22-2*).

The court acknowledged that FERC's nationwide ban on reactive power compensation remains in place despite its order to revisit the MISO decision. The court said that the "dispute here remains live because both orders are still under review" and said the generators are free to separately challenge the proceedings "even though success in only one proceeding might not fully redress [their] injury."

Although its ruling doesn't restore reactive power compensation in MISO, it does remove one barrier and help establish redressability, the court said.

Work inside Vistra's coal-fired Baldwin Power Plant in 2024 | *Mid-America Carpenters Regional Council*

Why This Matters

While the D.C. Circuit vacated FERC's order approving MISO's proposal, it said its ruling had no affect on Order 904, which itself is under review by the 5th Circuit.

It pointed out that MISO had been compensating generators for deadband-level reactive power production since the mid-2000s. Before the end of the practice, MISO paid about 400 generators for reactive power, which totaled $200 million annually according to one estimate. The "overnight" elimination of the revenue stream had generators claiming their wholesale power contracts would become unprofitable and undermine their ability to service debt and attract capital, the court noted.

FERC's reasoning that marginal costs of producing deadband-level reactive power are minor ignores that revenues in MISO have been significant, the court found. It also said FERC's solution that generators either renegotiate prices in existing power purchase agreements or increase asking prices in new contracts was unsatisfactory.

The court said FERC erroneously tasked generators with proving they relied on reactive power revenue when the commission should have burdened MISO with proving that an immediate end to the compensation was reasonable. It pointed out that FERC never considered a more gradual end to the compensation in MISO, even while Order 904 contained a 60-day phase-in period.

Order 904 is under review in the 5th U.S. Circuit Court of Appeals. The D.C. Circuit said that did not foreclose FERC "from giving a more thorough explanation in support of MISO's amendments on remand." ■

FERC Ends Show-cause over SPP FTR Changes

NorthWestern Agrees to Pay Penalty for Violation of SPP's Tariff

By Tom Kleckner

FERC has terminated a show-cause proceeding against SPP and accepted the RTO's proposal to revise its mark-to-auction (MTA) collateral requirement for financial transmission rights by including an additional re-marking mechanism for seasonal products.

The commission said in its Sept. 30 order that SPP's tariff "now fully addresses" its concerns in the proceeding, saying the mark-to-auction mechanism "sufficiently requires collateral to address the risk that a [transmission congestion rights] portfolio may decline in value over time" (*ER25-2261, EL22-65*).

"SPP's approach 'take[s] auction-clearing prices [ACPs] into consideration and thus incorporate[s] market expectations of the future values of the TCRs,'" FERC said, referring to a March order accepting the grid operator's MTA proposal. That order stopped short of terminating the show-cause proceeding that dated back to 2022. (See *FERC Accepts SPP Revisions to TCR Market, Maintains Show Cause.)*

"Specifically, SPP's proposal will apply ACPs from monthly auctions within the relevant season to re-mark the collateral requirements of seasonal TCRs, thereby ensuring that all TCR products are subject to a forward-looking pricing mechanism that reflects current market conditions," the commission said.

FERC said SPP's proposal to update collateral based on the most recent auction price for seasonal and monthly TCRs "provides sufficient protection when considered alongside other features of SPP's TCR collateral requirements and market design."

The commission disagreed with DC Energy's arguments that the show-cause proceeding should remain open to consider broader reforms to SPP's TCR market design. It found further reforms are unnecessary to address its concerns regarding the increased risk of default that results from a TCR portfolio that declines in value.

It also rejected the SPP Market Monitoring Unit's call to strengthen tariff language regarding ad hoc collateral adjustments. FERC agreed with SPP that under its tariff, the RTO already possesses "sufficient authority" through its existing credit policy to conduct ongoing credit assessments, revise customer credit limits and issue collateral calls in response to material changes in credit risk.

The commission granted SPP's request for waiver of the commission's 120-day prior notice requirement for good cause and accepted the proposal effective May 1, 2026, to allow the RTO to prepare for the TCR annual auction in 2026.

| © RTO Insider

Why This Matters

FERC said SPP's tariff "now fully addresses" its concerns around collateral risk related to market participants' transmission congestion rights.

FERC Penalizes NorthWestern

FERC approved a consent agreement between its Office of Enforcement and Regulatory Accounting and NorthWestern Energy, completing an investigation into whether the utility violated SPP's tariff over a wind farm's operation (*IN25-14*).

The Enforcement investigation found that NorthWestern failed to meet a deadline to convert its Beethoven wind farm project from a non-dispatchable variable energy resource (NDVER) to a dispatchable variable energy resource (DVER). NorthWestern acquired the 80-MW facility in South Dakota from BayWa Wind in July 2015, several months after it began commercial operation.

The utility, Beethoven's market participant, told SPP several times over a seven-month period before the acquisition that Beethoven was a qualifying facility (QF) and registered it as an NDVER. Beethoven was merged into NorthWestern, and in September 2015, BayWa Wind relinquished the facility's QF status.

As a wind-powered VER, the wind farm should have been registered as a DVER in 2015, according to SPP's tariff. However, it wasn't until February 2025 that NorthWestern completed the registration and conversion of Beethoven to DVER status.

NorthWestern neither admitted or denied the violation but agreed to: 1) pay a civil penalty of $40,000 to the U.S. Treasury; 2) disgorge $32,000, inclusive of interest, to SPP; and 3) provide compliance monitoring reports to Enforcement.

Enforcement opened the investigation after receiving a referral from SPP's MMU. ■

NV Energy to Withdraw from WRAP

Utility Announced Plans in Filing with Nevada PUC

By Henrik Nilsson

NV Energy has notified the Public Utilities Commission of Nevada that it plans to leave the Western Power Pool's Western Resource Adequacy Program (WRAP), citing five critical issues with the program's design.

Lindsey Schlekeway, market policy director at NV Energy, said in *written testimony* filed with the Nevada PUC on Aug. 29 that Nevada Power Company and Sierra Pacific Power Company — both doing business as NV Energy — are leaving the WRAP "due to inherent risks that outweigh the program's current benefits for both the companies and their customers."

The document containing the testimony had not been publicly available because of issues with the PUC's website.

"While the companies continue to recognize the value of regional collaboration in resource adequacy planning to ensure reliability across the West, there are five critical issues within WRAP's existing framework that significantly elevate risk exposure," Schlekeway wrote. "These concerns must be addressed before the companies can consider rejoining the program."

WPP Chief Strategy Officer Rebecca Sexton told *RTO Insider* on Oct. 2 that WPP is aware of NV Energy's filing but noted that WPP has not received formal notice that the utility is exiting WRAP.

"The deadline for notice is Oct. 31, in order to provide two years' notice before the first binding season," Sexton said. "We do expect some participants will exit the program. We understand this and respect it, and the door is always open for them to return. As we announced earlier this week, with the commitments we have in place, there is a critical mass of participants to move forward with our first binding season in winter 2027/28." (See *WRAP 'Binding' Phase Set for Winter 2027/28 After Utilities Affirm Commitment*.)

"Meanwhile, participants and stakeholders are able to suggest changes or updates to the WRAP, through our open and transparent governance process and task forces," Sexton added. "In fact, we currently have task forces and discussions with participants addressing some of the concerns being raised. We continue working hand in hand with participants and stakeholders to refine and optimize the program."

Why This Matters

NV Energy's withdrawal suggests that WRAP participants are dividing along Western day-ahead market choices.

The first issue highlighted in NV Energy's testimony concerns deficiency charge penalties. Schlekeway noted penalties could range from $16 million to $22 million for a 100-MW deficiency if it occurred during every month of the summer season.

"This makes joining the program troublesome for load-serving entities that are planning to catch up and meet increasing loads in an unprecedented time," according to the testimony.

'High Financial Risk'

Schlekeway said also that the electricity industry is grappling with a host of challenges, including supply chain issues and load growth that could cause projects to delay or miss commercial operational dates, potentially exposing NV Energy to deficiency penalties.

The Planning Reserve Margin policy is also subject to volatility, with year-over-year changes ranging from "minor adjustments to swings as large as 10%," Schlekeway contended.

"The combination of the high deficiency charges and the volatile PRM requirements creates high financial risk and planning challenges, especially amid supply chain disruptions and rapid load growth," according to the testimony.

The second issue relates to the emergence of day-ahead markets in the West. SPP requires all load-serving entities in its Markets+ day-ahead market offering to participate in WRAP. This could potentially disadvantage those WRAP members that choose to remain in CAISO's Western Energy Imbalance Market or opt to join the competing and soon-to-be-launched Extended Day-Ahead Market (EDAM), Schlekeway argued.

"Essentially, the WRAP voting model may dilute the influence of non-Markets+ participants leading to potential harm prior to the ability for the participant to exit the program, which occurs two years following a notification," Schlekeway wrote. "The WEIM and EDAM WRAP members may lose their veto power with the addition of participants that participate in Markets+."

The other issues include what Schlekeway called a "lack of market oversight and procurement mechanisms," as well as underutilization of transmission and uncertainty around operational holdback availability.

"The companies will continue to monitor the program's development and remain open to future participation should WRAP evolve to address these five critical issues," she wrote. "Until then, the companies will pursue alternative avenues to ensure regional reliability and resource adequacy for their customers."

The news extends a string of developments related to WRAP as the participation deadline looms.

On Sept. 29, 11 members reaffirmed their commitment to the program, saying they would begin participating during WRAP's first binding period in winter 2027/28. All but one of those members have also committed to joining Markets+.

The following day, PacifiCorp issued a letter asking the WPP's Board of Directors to allow WRAP participants to defer their decision to commit to the program's binding phase by at least one year, citing issues related to the development of Western day-ahead markets and other challenges. (See *PacifiCorp Asks WPP to Delay WRAP 'Binding' Phase Commitment Date*.)

PacifiCorp will begin trading in EDAM in 2026, while NV Energy is leaning heavily in favor of joining that market.

NV Energy did not respond to a request for comment for this story. ■

Xcel Battles Colo. Counties over Tx Project

Colorado's Power Pathway Aims to Encourage Eastern Plains Renewables

By Elaine Goodman

Xcel Energy is fighting two counties that are blocking a segment of the company's Colorado's Power Pathway transmission project.

Elbert and El Paso counties denied siting permits for the Power Pathway project in July.

Now, Public Service Company of Colorado (PSCo), an Xcel subsidiary, has appealed the permit denials to the Colorado Public Utilities Commission. PSCo is asking the commission to use its backstop siting authority to allow the project to move forward.

"While Public Service acknowledges that counties … have certain regulatory siting authority, they cannot and should not use such authority to preclude infrastructure projects that are necessary for Colorado's statewide interest," PSCo said in its application to the PUC.

During its Oct. 1 meeting, the commission set an Oct. 22 pre-hearing date for the Elbert County and El Paso County cases.

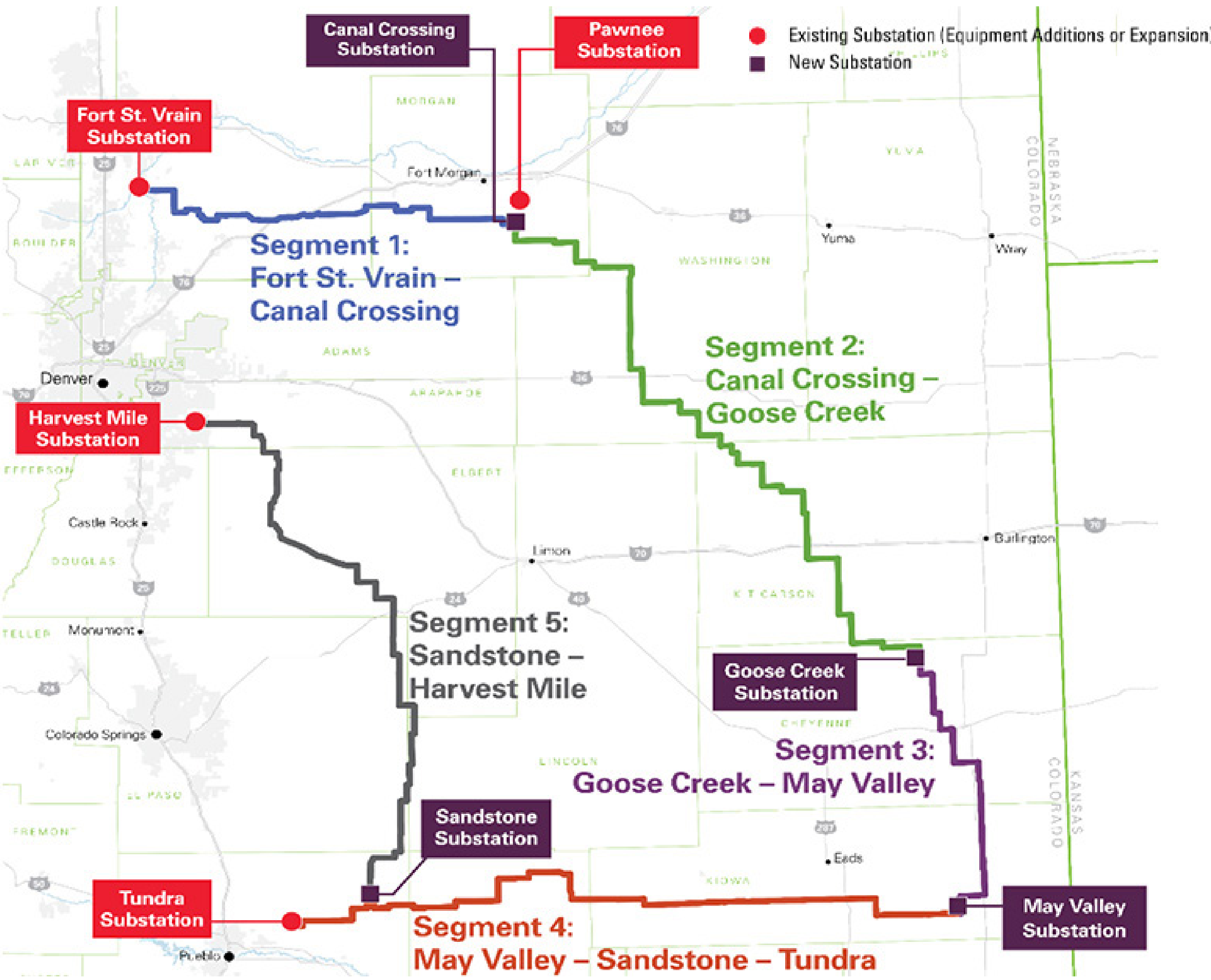
$1.7B Project

Colorado's Power Pathway is a $1.7 billion project that aims to transport wind and solar energy from the state's Eastern Plains to the Front Range region, which includes Denver and other cities. Plans call for 550 miles of new double-circuit, 345-kV transmission line along with four new substations and upgrades to four existing substations.

The project is being built in five segments. Segments 2 and 3 went into service in 2025, and construction is

Why This Matters

The Colorado's Power Pathway project aims to provide a backbone network transmission system in the eastern part of the state and contribute to grid reliability and resiliency.



Elbert and El Paso counties have denied permits for Xcel Energy to build Segment 5 of its Colorado's Power Pathway transmission project. | *PSCo* underway on segments 1 and 4. But the 130-mile-long Segment 5 has stalled due to permitting issues.

PSCo said the project is needed to meet the state's clean energy targets, including an 80% reduction in greenhouse gas emissions by 2030. The project will encourage development of new wind and solar generation in Eastern Colorado, PSCo said, in part by reducing the need for long gen-tie lines to connect resources.

The PUC approved a Certificate of Public Convenience and Necessity for the Power Pathway project in 2021, calling it "one of the most expansive and significant transmission proposals to be considered by the commission."

"This proposal comes at a critical time for Public Service, Colorado's largest utility, to transform its system and the ways in which it reliably generates and delivers energy for its customers in advance of clean energy targets," the commission said in an order granting the CPCN.

But in Elbert County, the board of county commissioners denied siting permits for a 48-mile section of the project. County commissioners said the company hadn't addressed wildfire risks, and residents' requests to move the line farther east "were dismissed." In addition, the transmission line would hurt ranching and farming in the county, reduce residential property values and create an "industrial scar" that would impact the rural aesthetic, the county commission said in a resolution.

PSCo said it provided documentation showing the transmission line would operate safely and that it was in a low wildfire risk area. And commissioner comments during public hearings revealed their real concerns, PSCo alleged.

According to PSCo, the commission chair stated that the line "serves no purpose here for Elbert County. And frankly, I don't care about Denver and Aurora. I really don't."

PSCo is not the local electric service provider for either Elbert County or El Paso County.

El Paso County Concerns

In El Paso County, where about 45 miles of transmission line would be built, the board of county commissioners expressed similar concerns. One commissioner wanted to know why the solar and wind farms couldn't be built closer to Denver, PSCo said in its application, while a resident pleaded to not turn their area into a "green energy dumping grounds of Denver."

PSCo also filed complaints against Elbert and El Paso counties in district court but said that's a separate matter from its application with the PUC.

PSCo asked the PUC to process its request on an expedited timeline so the company can stick to its construction schedule and avoid increased costs. In addition, "delayed availability of these resources also raises resource adequacy concerns as the Pathway project is necessary to deliver generation to meet increasing demand throughout Colorado," the company argued.

PSCo wanted a commission decision by January, but the PUC on Oct. 1 denied its request for expedited treatment. Instead, commissioners said they'd do their best to move the matter along quickly. ■

Minnesota PUC Approves BlackRock's Purchase of Allete

By Amanda Durish Cook

The Minnesota Public Utilities Commission approved the $6.2 billion sale of Allete to BlackRock's Global Infrastructure Partners and the Canada Pension Plan Investment Board in a unanimous decision Oct. 3.

All five commissioners agreed that the transaction, which would make Allete a private company, is in the public interest (E-015/PA-24-198). Allete — which owns Minnesota Power; Allete Clean Energy; and Superior Water, Light and Power — said in 2024 that the buyout is necessary to fund the fleet transition necessary to hit clean energy targets. (See *Canada Pension Board, Global Infrastructure Partners to Buy Allete*.)

The Minnesota PUC will issue a written order later in 2025. It gave Minnesota Power until Jan. 15, 2026, to file an alternative resource plan that reflects its new owners' commitments.

During deliberations at the commission's Oct. 3 meeting, Assistant Attorney General Richard Dornfeld said provisions to the deal negotiated in summer allowed it to cross the threshold of the public interest.

GIP and CPPIB agreed to several settlement provisions, including $50 million in rate credits for customers; another $50 million in clean energy funding for future resources that cannot be recovered in rates; $10 million in home efficiency improvements for low-income customers; up to $3.5 million in residential customer arrearage forgiveness; a reduction in return on equity from 9.78% to 9.65%, with a future cap of 9.78% through Dec. 31, 2030; a pledge to maintain local employment levels and seek local staffing on future projects; an agreement to participate in audits conducted by the Minnesota Department of Commerce; and penalties for noncompliance with commitments.

Minnesota Power's Boswell Energy Center undergoing environmental control construction | *The Boldt Co.*

Why This Matters

All five Minnesota regulators said they were initially uneasy with two private equity firms taking Allete private; however, they said late-stage ratepayer protections convinced them to approve the sale.

Additionally, GIP and CPPIB have guaranteed Allete will have access to capital to fund its five-year transmission and renewable energy plans. Allete is set to retain its Duluth, Minn., headquarters and be governed by a majority independent board of directors, with multiple seats reserved for residents of Minnesota and Wisconsin.

Minnesota regulators addressed Minnesota Power's new ties to BlackRock before their vote. BlackRock, the world's largest asset manager at more than $12 trillion in accounts, acquired GIP in a $12.5 billion deal in 2024. Consumer advocacy groups are apprehensive that GIP, motivated by profit, would raise rates.

The sale is the latest in a trend of private equity snapping up public utilities. GIP is reportedly also exploring the purchase of AES. Blackstone Infrastructure, on the other hand, announced intentions to close on TXNM Energy, the parent of the Public Service Company of New Mexico and Texas-New Mexico Power, for $11.5 billion.

Commissioners Tell Firms to Build Trust

All five commissioners said they had reservations about the sale but were assuaged by the firms' additional promises.

Vice Chair Joseph Sullivan said that while he didn't know what would happen in the long term, the near- and medium-term benefits of the transaction are undeniable over Minnesota Power's status quo. He said the sale would likely "take a very significant bite" out of the utility's next rate case.

However, Sullivan advised Minnesota Power and its new owners to build credibility with its ratepayers and those who opposed the sale.

"If you don't build that credibility, that will redound unfavorably to everybody, including this commission," Sullivan said. "My hope is you take that seriously. … In the world right now, in this country, there's a significant amount of uncertainty and concern, and I think for a lot of people in Northen Minnesota right now, a lot of people in the state, they're probably saying, 'Well, just another crappy thing that's happened today.'"

Sullivan told GIP and CPPIB to leverage the current doubt surrounding the sale, calling "trust the currency of the realm."

Commissioner Audrey Partridge said she was pessimistic about the motivations of private equity and examined the deal assuming "the absolute worst" of GIP and CPPIB. Partridge said in every scenario she tested, she could not see a way that the investors would simultaneously profit while harming the utility and its customers.

"I cannot remark on the character of these investors before us, but I was unable to maintain my cynicism as I went through the exercise of applying these commitments to all of the possible scenarios raised in the docket of how they might take advantage of customers and our communities," Partridge said.

PUC Chair Katie Sieben said Minnesota Power needs "massive investment," not only because of the state's 100% carbon-free energy mandate by 2040, but also because many resources in the utility's fleet are aging out and need investment.

The Citizens Utility Board of Minnesota said in a statement following the decision that it continued to agree with an administrative law judge who reviewed evidence in docket in July and *concluded* that risks of an earlier version of the deal "outweigh the possible benefits."

"Though we disagree with the commission's decision, we genuinely hope they are correct in their assessment. We also appreciate the commission's efforts to impose conditions that help mitigate risk of harm to ratepayers," CUB said. Regardless of Minnesota Power's owners, the organization would continue to advocate for ratepayers, it said.

The Sierra Club predicted the sale would "pad private equity investors' pockets."

"BlackRock and predatory private equity firms have long proven that their mission will always be to relentlessly pursue profit, no matter the harm it causes to communities," said Jenna Yeakle, with the Sierra Club's Beyond Coal campaign.

Before the approval, Minnesota environmentalist advocacy group CURE had said, "Short-term and illusory commitments do not mitigate taking this utility into the shadows of private equity management and cannot fully remedy the harms to transparency, reliability, affordability and public confidence that will flow from an approval of this deal."

'Valuable' Pushback

Commissioner Hwikwon Ham said overall, the PUC had to balance Allete's continued risk exposure to the financial market and its industrial customers' susceptibility to business cycles against the potential risk of partners' misbehavior. He said GIP and the CPPIB offered a higher probability of providing Minnesota Power with more stable equity.

Ham urged all the opposing parties in the docket to stay vigilant and participate in Minnesota Power's upcoming rate cases, resource planning and other financial filings.

"You guys develop the record; bring it to us. If there's any misbehavior, we can deal with it. So, a lot of those risks can be managed through our regulatory process," Ham said. He also asked stakeholders not to hold preconceived notions that the new ownership will be bad.

Ham noted a potential abuse of affiliated interests but said he believes existing U.S. Securities and Exchange Commission regulations are adequate to manage BlackRock.

"I started with very strong skepticism in this transaction," Ham said. He thanked opposing parties and ratepayers for their arguments and said he was surprised by the firms' flexibility to agree to new provisions.

Ham also advised GIP and CPPIB against making "Minnesota Power ratepayers mad."

Commissioner John Tuma likewise said he was uneasy about what the deal would mean for Minnesota's regulatory compact and said the concerns around affiliated interests are "real." However, he said if the deal grows Minnesota Power as promised, it would be a win for ratepayers.

"This is a new, different way of doing it, as opposed to, say, some of the other mergers we've seen in the past," Tuma said. He said the "pushback" from CUB was valuable and asked it to continue to serve as a watchdog.

"It's a new path; there's a lot more bramble-clearing to be done. And we want you to help clear that bramble so we can cut a new path," Tuma said.

GIP founding partner Jonathan Bram told the commission that the company's fiduciary duty means that it would not disadvantage Allete to benefit another company under BlackRock's umbrella.

"Trust … is our stock and trade, and establishing that trust, maintaining that trust, is paramount to how we will … manage this. It is essential," Bram said.

Bram also said the SEC and "international equivalents" regulate what GIP does, even before the BlackRock acquisition.

Andrew Alley, CPPIB's head of infrastructure for North America, said the board could face "significant ramifications" if it tried to benefit one account at the expense of another.

"By our research, no other utility acquisition in America is generating this amount of value per customer, which we estimate to be approximately $200 million," Jennifer Cady, Allete vice president of public policy and external affairs, told the commission before the vote. "None of these financial benefits exist without this transaction."

Sieben said she was proud of the work the firms, environmental groups, labor unions and other stakeholders did to hammer out the final terms of the transaction.

"I think it's pretty clear that because of the collective work of the agency, of us, our staff, the process we've engaged in a public and legal manner, we have made the petition better, and it will be to the betterment of Minnesota Power customers," Sieben said. ■

Duke Asks for More Gas and Batteries, Delayed Coal Retirements to Meet Demand

By James Downing

Duke Energy on Oct. 1 filed its long-range plan for its system in the Carolinas with the North Carolina Utilities Commission, calling for more natural gas-fired generation and batteries while keeping existing coal plants online to meet accelerated demand for electricity.

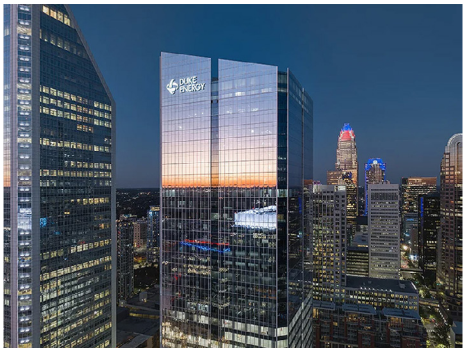
The 2025 Carolinas Resource *Plan* reflects the $19 billion in investments, representing 25,000 jobs, the states have attracted so far this year, most of which are from new manufacturing plants.

"North Carolina is the top state for business, and our focus is on ensuring Duke Energy's low energy rates continue to support this region's economic success," Duke Energy North Carolina President Kendal Bowman said in prepared remarks. "By expanding our diverse generation portfolio and maximizing our existing power plants to meet growth needs, we will ensure reliable energy while saving all our customers money."

Duke said its plan should lead to average power bills growing by 2.1% over the next decade, which is below expected inflation and lower than the previously approved resources plan filed in 2023.

Customer energy needs over the next 15 years are forecast to grow at eight times that of the last decade-and-a-half, double the rate Duke was expecting in 2023.

Duke has a 22% reserve margin target that it plans to meet by 2031, but it said it is continuing to re-evaluate that in light of growing demand, declining imports from neighboring systems and the risk of extreme temperatures going forward.



| *Duke Energy*

"To meet the 22% reserve margin necessary for system operators to have the resources they need in real time, the companies must continue their immediate buildout of available resources to meet the increasing need for capacity driven by growing loads and retiring coal generation," Duke said in testimony at the NCUC. "New gas combustion turbines and combined cycle units, battery storage and solar are the resource types that are executable over the near term to put flexible megawatts into the hands of our system operators."

As in 2023, Duke plans to build five combined cycle natural gas power plants, but it now also plans to build seven combustion turbine gas plants, up from five in the last plan. It also wants to build more LNG storage to cut fuel costs and hedge against price volatility.

The target for battery storage was also expanded in the plan — 5,600 MW by 2034, up from 2,900 MW in the 2023 iteration — which will help meet near-term growth and use federal tax credits, the company said.

The plan calls for 4,000 MW of new solar power by 2034, to be deployed in a way that maximizes customer benefits from the remaining federal energy tax credits.

Expanding nuclear power is also being considered, with Duke evaluating the potential for new light-water reactors in addition to small modular reactors. New nuclear capacity could be up and running by 2037 at its Belews Creek plant in North Carolina or its Cherokee County plant in South Carolina.

Wind is not an economically viable resource for the Carolinas through 2040, though Duke said it would reassess that in 2027.

With the federal government easing regulations on coal, Duke said it is targeting two- to four-year extensions of its units that have dual-fuel capability (the Belews Creek, Cliffside and Marshall plants), as it said a few more years of operation would help deal with load growth. Over the long term, Duke said it was maintaining "an orderly exit from coal as approved by state regulators."

Why This Matters

Duke Energy wants more dispatchable capacity (both batteries and fossil-fired plants) to help meet rising demand, which has seen its projected growth accelerate since its last major update filed in 2023.

The utility is also working to expand capacity at existing plants, adding nearly 300 MW to the grid at four nuclear stations, expanding its Bad Creek pumped storage plants by an additional 280 MW and upgrading seven other hydro facilities. It also plans to upgrade its natural gas fleet in ways that cut costs and emissions, it said.

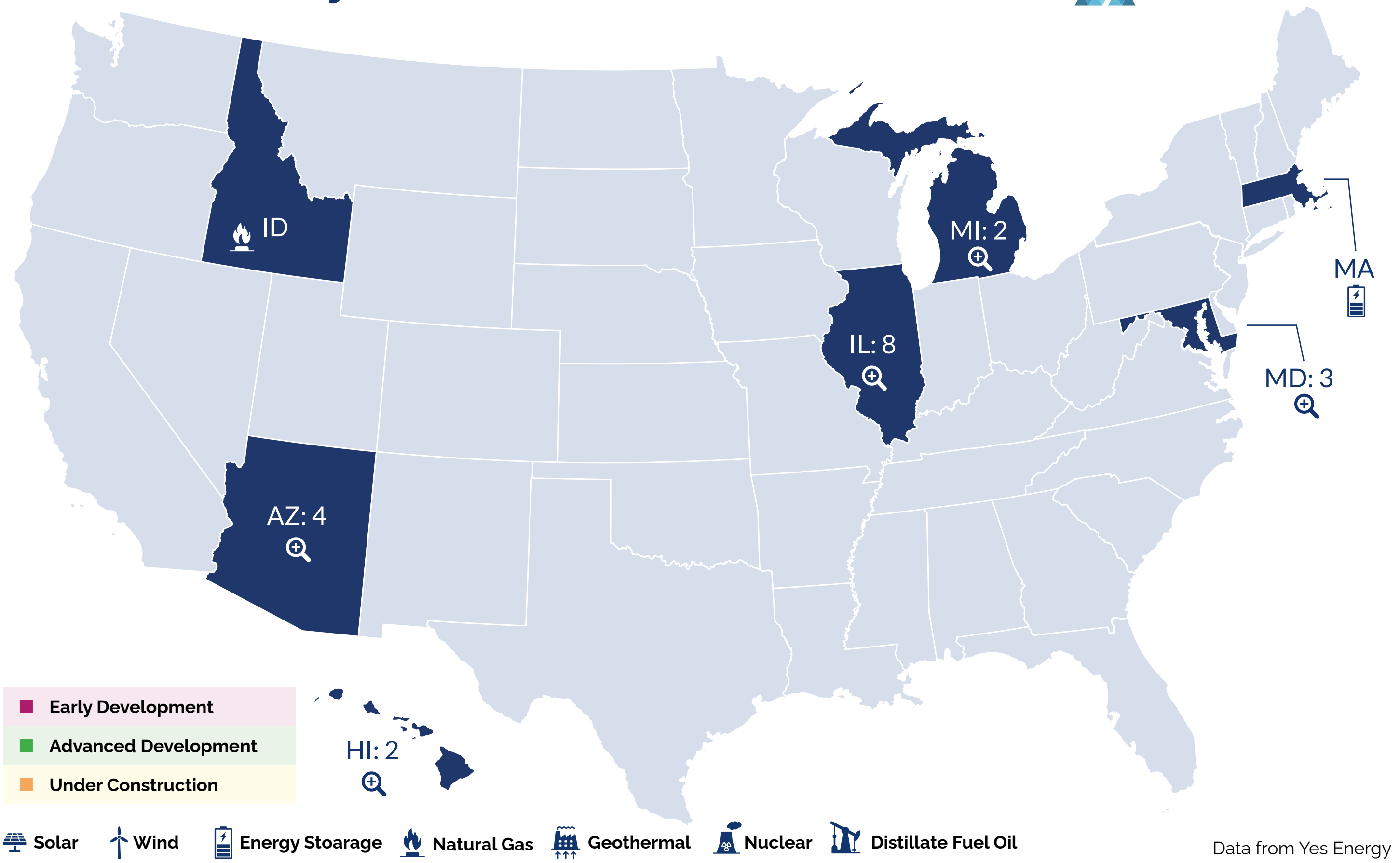
The proposed plan came under criticism from the Southern Environmental Law Center, the Sierra Club and Vote Solar, which are active in the proceeding before the NCUC. The plan comes after a new North Carolina law that eliminated the state's interim carbon-reduction target of 70% by 2030. The groups argue the plan risks higher bills by backing new natural gas and unproven new technologies. (See *Duke Highlights Legislative Wins in Q2 Earnings Call*.)

"We're concerned that regulated monopoly Duke Energy is continuing to rely on expensive new gas power plants, leaving North Carolina families on the hook for escalating fuel costs and making it harder to reach the 2050 carbon-neutrality requirement," SELC Senior Attorney David Neal said in a statement. "Duke yet again appears to have fallen short of taking full advantage of energy efficiency, load flexibility, renewables and storage, which remain the cheapest and fastest suite of options for meeting rising demand."

Parties have 180 days to file comments and critiques on the plan with the NCUC, which will hold public hearings and an evidentiary hearing as it weighs the merits of Duke's filing. ■

Generation Projects Added in the Past Week

YES ENERGY



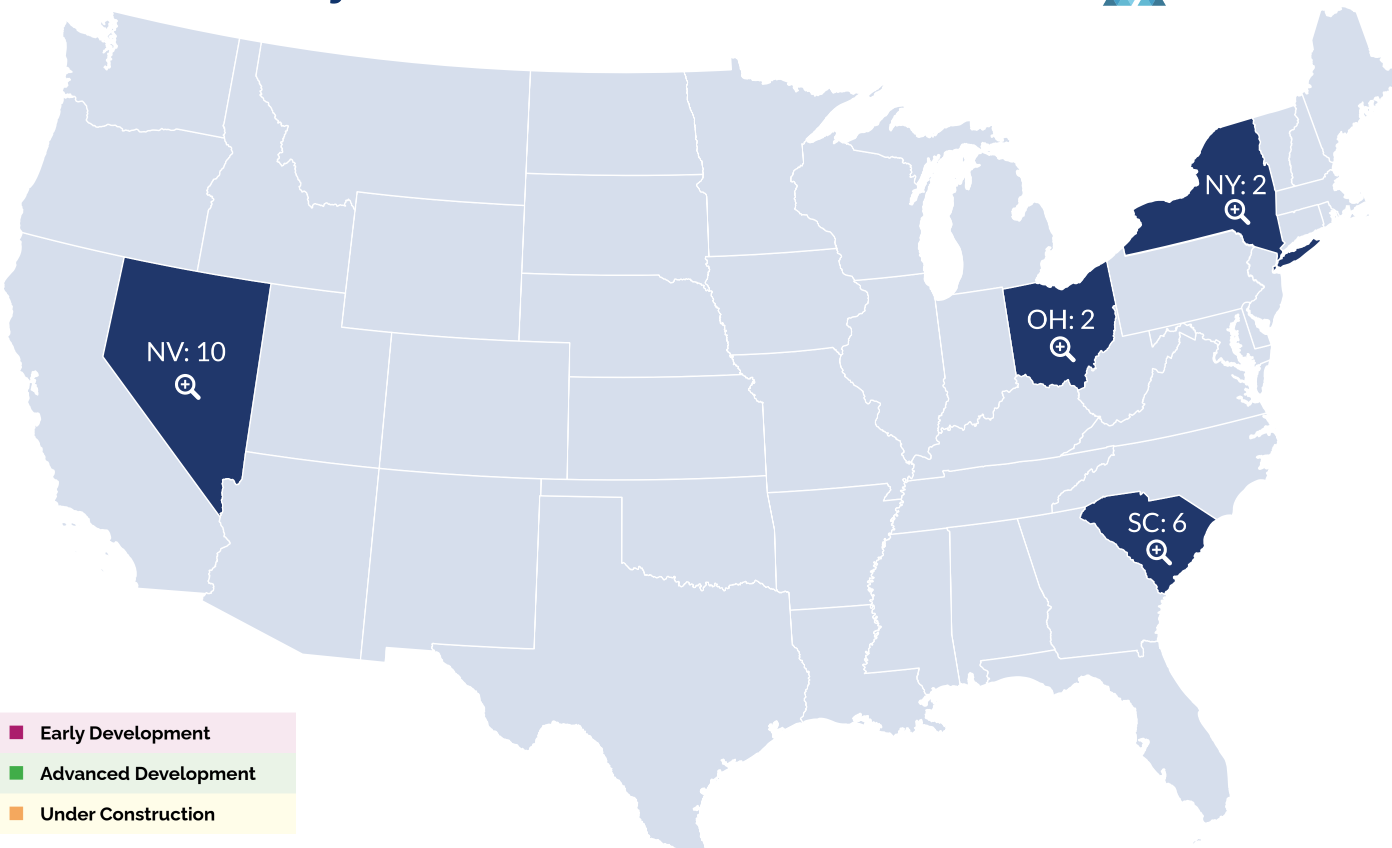
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Harquahala Sun VI (Harq 6 Solar)	Carlyle Group LP	Copia Power	AZ		2028
	Copper Crossing BESS (Phase 3)	Salt River Project		AZ	5	2028
	Maricopa Energy Center	Carlyle Group LP	Copia Power	AZ	550	2028
	Maricopa Energy Center BESS	Carlyle Group LP	Copia Power	AZ	550	2028
	Kaawanui Solar	AES Corp.	AES Hawai'i	HI	43	2028
	Kaawanui Solar BESS	AES Corp.	AES Hawai'i	HI	43	2028
	Bennett Gas Expansion Project	IdaCorp	Idaho Power Company	ID	167	2029
	TPE IL DE447 Solar	TurningPoint Energy	TPE Development, LLC	IL	5	2100
	Polk Road Solar	Trajectory Energy Partners		IL	5	2100
	CSG Kingston Solar	Neumann Companies	SunVest Solar, LLC	IL	5	2100
	Marion Township Solar 2	Energy Capital Partners	New Leaf Energy	IL	5	2026
	Donato Solar	BTB Energy		IL	4	2100
	Donato Storage	BTB Energy		IL		2100
	Johnson Lake Solar 3	Encore Renewable Energy	Encore Green, LLC	IL	5	2026
	Johnson Lake Solar 4	Encore Renewable Energy	Encore Green, LLC	IL	5	2026
	Pear Tree Energy Center	Mission Clean Energy		MA	170	2029
	Tower Logistics Solar Project	Wunder Power		MD	9	2026
	Amish Road Solar Project	Energy Capital Partners	New Leaf Energy	MD	5	2100
	Bessie Clemson Road Solar	Alder Energy		MD	5	2027
	Fiddlehead Solar	InfraRed Capital Partners	Hecate Energy	MI	225	2028
	Butterworth Landfill Solar	Grand Rapids, City of		MI	15	2027

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

Generation Projects Added in the Past Week

YES ENERGY



- Early Development
- Advanced Development
- Under Construction

Solar | Wind | Energy Stoarage | Natural Gas | Geothermal | Nuclear | Distillate Fuel Oil

Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	North Valmy Peaking (Valmy Capacity Project)	Berkshire Hathaway Energy	NV Energy	NV	400	2028
	Arida 2c Solar	EIG Management Company	Avantus	NV	200	2028
	Arida 2c Storage	EIG Management Company	Avantus	NV	200	2028
	Flygirl Solar Farm	Brookfield Asset Management	Scout Clean Energy	NV	3,000	2032
	Flygirl Storage	Brookfield Asset Management	Scout Clean Energy	NV	3,000	2032
	Star Peak Solar	Brookfield Asset Management	Scout Clean Energy	NV	300	2031
	Star Peak Storage	Brookfield Asset Management	Scout Clean Energy	NV	300	2031
	Tidewater Solar	Brookfield Asset Management	Scout Clean Energy	NV	1,200	2031
	Tidewater Storage	Brookfield Asset Management	Scout Clean Energy	NV	1,200	2031
	Scorpio Energy Center	Arevia Power		NV	400	2100
	Horning Solar	Aspen Power		NY	5	2025
	Orleans DG Solar	NextEra Energy, Inc.		NY	5	2025
	Highland County BESS	NextEra Energy, Inc.	NextEra Energy Resources	OH	200	2100
	Hanging Rock Energy Solar	Mitsubishi Corporation	Nexamp, Inc.	OH	6	2027
	Brush Hollow Solar	Renewable Energy Services Limited	SR1 RES Holdco I LLC	SC	68	2030
	Brush Hollow Solar BESS	Renewable Energy Services Limited	SR1 RES Holdco I LLC	SC	25	2030
	Seeley Solar BESS	Renewable Energy Services Limited	SR1 RES Holdco I LLC	SC	27	2027
	Stripe Solar	Palladium Energy		SC	65	2028
	Throwback Solar	Palladium Energy		SC	75	2030
	Fieldstone Solar	Grenergy Renewable Energy Co	Grenergy USA, LLC	SC	75	2030

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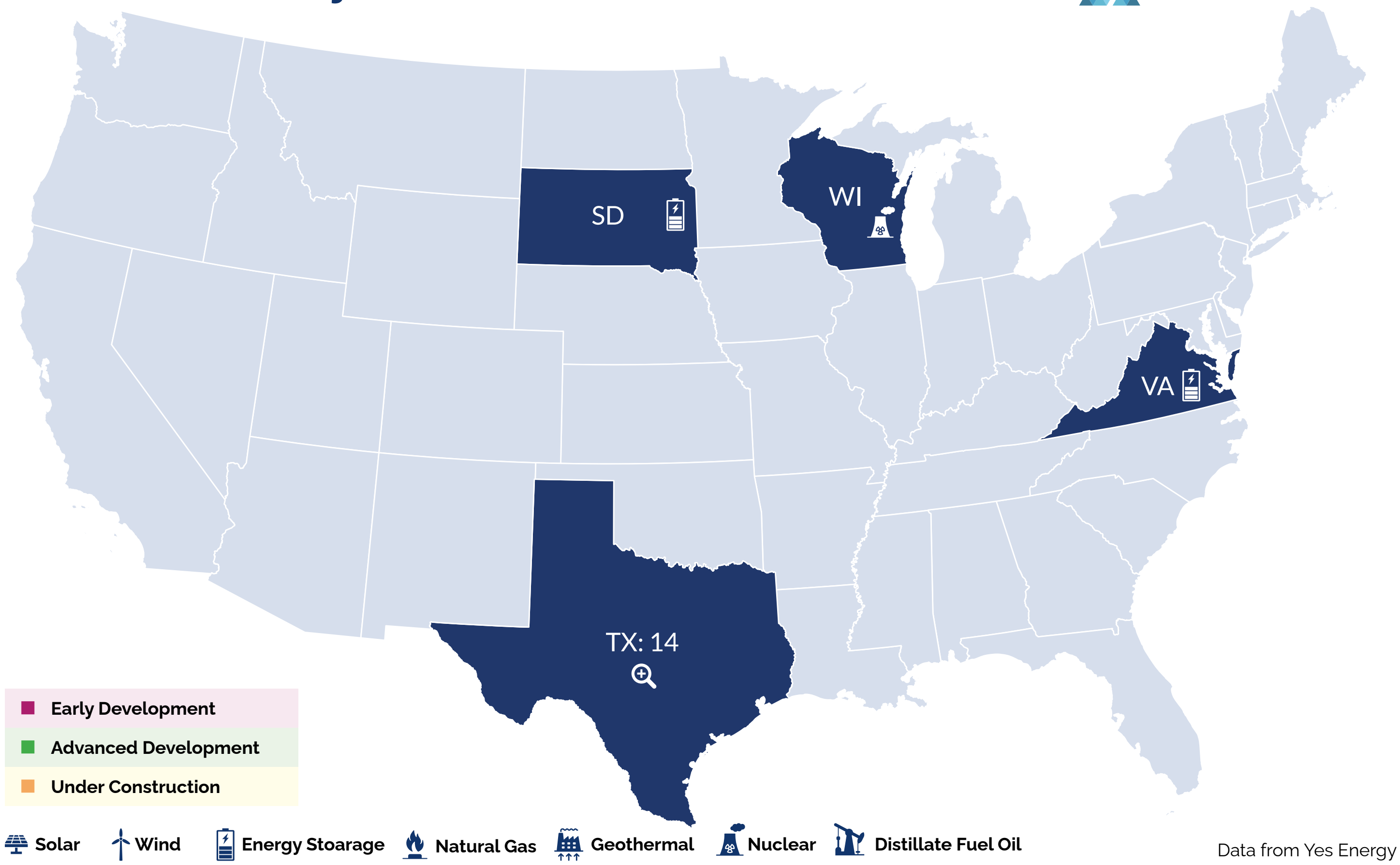
Generation Projects Added in the Past Week

YES ENERGY



Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Crowned Ridge Energy Storage	NextEra Energy, Inc.		SD	120	2027
	Cielo Vista Power Gas Plant	Ownership Undisclosed		TX	335	2028
	Cowboy Power Gas Plant	Ownership Undisclosed		TX	252	2028
	Falcon BESS	Ownership Undisclosed		TX	517	2028
	Galaxy I Solar	Ownership Undisclosed		TX	83	2028
	Gulf Gateway Storage One	Ownership Undisclosed		TX	301	2027
	Prairie Branch BESS	Ownership Undisclosed		TX	310	2028
	River Boat Power Gas Plant	Ownership Undisclosed		TX	334	2028
	Sweetheart BESS	Ownership Undisclosed		TX	310	2029
	Sweetheart Solar	Ownership Undisclosed		TX	301	2029
	Three Ranches BESS	Ownership Undisclosed		TX	103	2027
	Tri-X BESS 1 SLF	Ownership Undisclosed		TX	206	2027
	Star Of Texas Solar	NextEra Energy, Inc.	Bouldevard Associates, LLC	TX	415	2029
	Barkley Creek Solar	Hanwha Group	174 Power Global	TX	312	2029
	Magnet Storage	BNB Renewable Energy Holdings	BNB Renewables	TX	427	2028
	Muy Grande Solar	AES Corp.		TX	503	2028
	Bakers Pond Storage	RWE	RWE Renewables Americas	VA	20	2026
	Kewaunee Power Station Unit 2	WEC Energy Group		WI		2038

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

Company Briefs

Automakers See Record EV Sales

Ford Motor, General Motors and Hyundai all reported record quarterly sales for EVs from July through September.

GM and Ford said third-quarter sales increased roughly 8% from a year earlier, with EV sales more than doubling for GM. Ford said EV sales increased by 30% compared with the third quarter of 2024. Hyundai reported a 13% year-over-year sales increase during the third quarter, also led by doubling sales of EVs.

Other automakers reported increases as well.

More: *CNBC*

OpenAI Announces Plans for 5 More Data Centers

OpenAI announced its flagship AI data center in Texas will be joined by five others around the U.S. as the ChatGPT maker aims to make good on the $500 billion infrastructure investment promoted by President Donald Trump earlier this year.

Stargate, a joint venture between OpenAI, Oracle and Softbank, said it is building two more data center complexes in Texas, one in New Mexico, one in Ohio and another in a Midwest location it hasn't yet disclosed. The first center in Texas will require about 900 MW to power eight buildings.

More: *The Associated Press*

Vistra Gets FERC Approval for Gas Acquisition

Vistra last week announced it has received FERC approval for its previously announced acquisition of seven natural gas facilities from Lotus Infrastructure Partners.

The acquisition, first announced in May, would add 2,600 MW of capacity from five combined-cycle gas turbine plants and two combustion turbine plants to Vistra's portfolio.

The transaction remains on track to close within a few months.

More: *Vistra*

Federal Briefs

Judge Denies Proposed Pause of US Wind Lawsuit amid Shutdown

Judge Stephanie Gallagher last week issued a denial to the Trump administration's motion to stay a lawsuit challenging US Wind's proposed wind farm off the coast of Delmarva, quashing the possibility of the lawsuit's pause during the government shutdown or a delay of a scheduled status hearing.

The Trump administration filed a motion to stay the ongoing lawsuit against it and US Wind on Oct. 2, arguing the current government shutdown has limited its attorneys' ability to respond to the suit. The administration also asked the judge to delay an upcoming status conference on Oct. 7 until funding has been restored to the Department of Justice.

US Wind objected to the stay, saying one "would be inappropriate at this juncture, considering the imminent and existential risks that US Wind faces given the government's abandonment of its defense of the project."

More: *WBOC*

EPA Moves to Relax Climate Super Pollutant Rules

The EPA last week announced it plans to relax a Biden-era rule on hydrofluorocarbons (HFCs).

EPA Administrator Lee Zeldin claimed the Biden administration's plan for cutting the production and consumption of HFCs, which aimed for an 85% reduction by 2036, did not give companies enough time to meet the deadlines. Under a new proposal, the residential air-conditioning sector, retail food refrigeration sector, cold storage warehouses and semiconductor manufacturing would potentially have five more years to switch to alternative coolants.

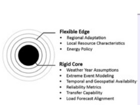
The public will have 45 days to comment on the proposal once it appears in the *Federal Register*.

More: *The New York Times*

National/Federal news from our other channels

Lawsuit Seeks Reinstatement of Solar for All — NetZero Insider

Lawmakers Divided on CISA 2015 Reauthorization — ERO Insider



NERC Staff Call for Resource Accreditation Guideline — ERO Insider

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

State Briefs

ARKANSAS

Google, State Officials Celebrate Start of $4B AI Data Center

Google last week officially announced the first phase of its West Memphis cloud and artificial intelligence data center project.

West Memphis Mayor Marco McLendon lauded the $4 billion investment through 2027, located on 1,100 acres near the Arkansas-Tennessee state line.

Entergy Arkansas will provide power to the facility via a solar array and existing generation.

More: *Arkansas Advocate*

CALIFORNIA

PG&E Unveils $73B Plan to Meet Data Center Demand

PG&E last week announced plans to spend $73 billion by 2030 for transmission upgrades to meet data center demand.

The company said in July it was working to serve 10 GW of new electricity demand from data center projects over the next 10 years.

PG&E has also been blamed for sparking numerous wildfires and aims to build nearly 700 miles of underground power lines and complete 500 miles of additional wildfire safety system upgrades between 2025 and 2026.

More: *Reuters*

FLORIDA

Gov. DeSantis Appoints Payne, Ortega to PSC

Gov. Ron DeSantis last week appointed former Rep. Bobby Payne and Ana Ortega to the Public Service Commissions.

Payne, a former Seminole Electric Cooperative executive who now owns and operates an eponymous consulting firm, served in the House from 2016 to 2024. Ortega is a chief policy adviser to PSC Chair Mike La Rosa.

Both appointments are subject to Senate confirmation.

More: *Florida Politics*

MASSACHUSETTS

Gov. Healey, Lawmakers Decry Liberty Utilities' Proposed Rate Hikes

Gov. **Maura Healey** last week condemned Liberty Utilities' proposed gas rate hike, describing it as "disappointing and deeply problematic."

Attorney General Andrea Campbell also filed a notice of intervention, which calls for an investigation into the proposal.

The proposal, which is under review by the Department of Public Utilities, calls for an average rate increase of 55.5%, though certain customers could see monthly bills increase by roughly 80%. Liberty Utilities estimates the rate hikes will generate more than $55.8 million in revenue. If approved, the rate hikes would go into effect in May 2026.

More: *WPRI*

MICHIGAN

PSC Approves Gas Rate Hike for Consumers Energy

The Public Service Commission last week approved Consumers Energy's request for a natural gas rate hike.

The $157.5 million increase, which will go into effect Nov. 1, will raise the average residential bill by $6.44/month.

Consumers initially sought a $248 million rate increase before amending its request to $217 million.

More: *Detroit Free Press*

RHODE ISLAND

Providence Gives 1st Passage to Gas-powered Leaf Blowers Ban

Providence councilors last week voted 8-3 to approve a citywide ban on gas-powered leaf blowers in its first of two votes on the proposal.

If the ordinance becomes law, the first phase allows the use of gas-powered blowers only between Oct. 1 and Dec. 15 from 2028 through 2033. City departments would also stop using the blowers in 2028.

The ordinance will need to be voted on by the full city council once more before heading to Mayor Brett Smiley's desk.

More: *WPRI*

WEST VIRGINIA

Mon Power, Potomac Edison File IRP with PSC

Mon Power and Potomac Edison, subsidiaries of FirstEnergy, last week filed their 10-year Integrated Resource Plan with the Public Service Commission.

The plan proposes keeping the Fort Martin and Harrison coal-fired plants operational through the next decade, exploring the addition of a 1,200-MW natural gas combined-cycle plant by 2031 and adding 70 MW of utility-scale solar by 2028.

More: *WVNews*

WISCONSIN

NextEra Nuclear Units Get 20-year License Extension

NextEra Energy last week announced that the Nuclear Regulatory Commission has approved the license renewal for two units of its Point Beach plant for another 20 years.

The approval extends operations at Units 1 and 2 through 2050 and 2053, respectively.

NextEra said the units, which began operations in the early 1970s, supply about 14% of the state's total electricity.

More: *Reuters*

WYOMING

Naughton Plant to Stop Burning Coal

Rocky Mountain Power last week reaffirmed its plans to convert its Naughton coal power plant to natural gas by the end of the year.

The company has also switched two of the units at its Jim Bridger coal plant to natural gas. It plans to do the same for three of the four units at its Dave Johnston coal plant by the end of the decade. The other unit will fully retire in 2027.

More: *Wyoming Public Radio*