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CAISO/WEST

California Pathways Bill Delayed After Organizations Withdraw Support

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The delayed hearing showcases the difficulties in drafting a law to create an independent RO that can balance California's interests with those of the rest of the West.

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ISO-NE

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Retiring ISO-NE CEO van Welie Reflects on 25 Years at the RTO (p.28)

ISO-NE CEO Gordon van Welie, who has led the organization for the bulk of its history, said he's confident about the organization's direction, but that a supportive federal and state regulatory environment will be key to ensuring resource adequacy in the 2030s and beyond.

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Sternberg, Naccari & White

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Canada's electricity grid will need major infrastructure investments to handle a projected doubling in load over the next 25 years.

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In this week's issue

Rubber Stamp? Has the NRC Lost its Independence?

By Stephen A. Smith

Stephen A. Smith

The pace of undermining the statutory authority of the Nuclear Regulatory Commission to serve as the cornerstone of nuclear safety in the United States and across the world is accelerating.

The recent directive by Department of Government Efficiency (DOGE) staff member *Adam Blake to NRC staff to "rubber stamp"* Department of Energy (DOE) and Department of Defense (DOD) nuclear projects highlights how far and fundamentally these cracks have advanced in the pillars of nuclear safety culture within the federal government.

There is a saying: "Nuclear power is not inherently unsafe, but nuclear power is inherently unforgiving." The implication is clear: Inattention to safety details has significant consequences. These concerns led Congress to wisely separate the original Atomic Energy Commission (AEC) into two agencies with constructive tensions. One is the DOE, which studies and promotes multiple forms of energy, including nuclear power. The other is the NRC, with the function of nuclear safety above all else.

During the 70-plus-year experiment with nuclear power, "defense in depth" safety margins have prevented nuclear accidents from the mundane to the catastrophic. Yet we have also seen *numerous near misses*, such as Browns Ferry (1975) and Three Mile Island (1979), and tragic failures at Chernobyl (1986) and Fukushima (2011).

With the advent of lower-cost hydraulically fractured fossil gas burned in combined cycle turbines and low-cost renewable wind, solar and storage, nuclear power no longer is a low-cost provider. New nuclear projects also failed to stay on budget and on schedule.

The past three nuclear reactors to come online, all in the nuclear-friendly southeastern U.S., highlight the failures. TVA's Watts Bar 2 was *over 40 years behind schedule and cost $6.1 billion*, while Georgia Power's Vogtle 3 and 4 were *seven years delayed and $21 billion over budget*. While thoughtful utility managers have moved away from nuclear power to embrace less risky, more predictable, and less complex energy solutions, nuclear zealots have sought to blame "over-regulation" and "government bureaucracy" for problems inherent in nuclear technology itself.

Why This Matters

The ultimate tragedy is that weakening safety oversight precisely when unproven reactor technologies need the most rigorous review sets the stage for the kind of serious accident that could devastate public confidence in nuclear power for generations, says Stephen A. Smith.

TVA's Watts Bar Unit 2 | *TVA*

Over the past decade, the NRC has become the favorite whipping boy of zealots beholden to a stagnant industry. Industry lobbyists have persistently chipped away at the structural pillars of safety and independence at the NRC while justifying the restructuring — i.e., weakening — of the NRC as needed for nuclear power's survival.

The Nuclear Energy Innovation Capabilities Act (NEICA) of 2017, Nuclear Energy Innovation and Modernization Act (NEIMA) of 2019, and Accelerating Deployment of Versatile, Advanced Nuclear for Clean Energy Act (ADVANCE Act) of 2024 have all been the hammers and chisels in the legislative toolbox. These moved with bipartisan support, further eroding safety and the NRC's independence.

The ADVANCE Act proved particularly damaging, as it required the NRC to alter its mission statement to ensure licensing "does not unnecessarily limit the benefits of civilian use of radioactive materials and nuclear energy technology to society." This represents a fundamental departure from the agency's safety-first mandate, introducing promotional language that echoes the very conflicts of interest that led to the AEC's dissolution in 1974.

Former NRC commissioners have sounded the alarm about these dangerous trends. "An independent regulator is one who is free from industry and political influence," *warned Allison Macfarlane,* who served as NRC chair under President Obama. "Once you insert the White House into the process, you don't have an independent regulator anymore." *Three former NRC chairs jointly warned* that recent changes "serve to weaken protections for those who work in or live near reactors."

The irony is profound: Just as the nuclear industry seeks to expand deployment of advanced reactor designs — technologies that are largely unproven and require more rigorous safety review, not less — the regulatory framework is being systematically weakened. These new reactor designs, from small modular reactors to advanced fast reactors, represent significant departures from existing light-water reactor technology. They require intensive safety analysis precisely because they lack the decades of operational experience that inform current safety protocols.

This regulatory erosion threatens to undermine the very public confidence the nuclear industry desperately needs to expand. Edwin Lyman of the Union of Concerned Scientists warned that the Trump administration's approach could "take talent and resources away from oversight and inspections and put them into licensing," *calling the strategy* "totally misdirected."

The potential consequences extend beyond U.S. borders, as former NRC officials noted: "If it becomes clear that the NRC has been forced to cut corners on safety and operate less transparently, U.S. reactor vendors will be hurt" internationally, since "a design licensed in the United States now carries a stamp of approval that can facilitate licensing elsewhere."

As an unbridled Trump returned to the White House pontificating about a "golden era" and "energy dominance in America," the die was cast for the NRC. DOGE staff infested the NRC and DOE, *Trump's May nuclear executive orders* solidified the collapse of the NRC's safety role and independence, and Adam Blake's "rubber stamp" comment was just the silent part said out loud. The structural pillars that have protected Americans from nuclear accidents for five decades are cracking under the weight of industry pressure and political interference.

The ultimate tragedy is that weakening safety oversight precisely when unproven reactor technologies need the most rigorous review sets the stage for the kind of serious accident that could devastate public confidence in nuclear power for generations — the very outcome the industry claims to want to avoid. ■

Stephen A. Smith is executive director of the Southern Alliance for Clean Energy.

LaCerte Nominated to Complete Phillips' Term at FERC

By Ken Sands

The White House has *nominated* David LaCerte to be a FERC commissioner for the remainder of the term expiring June 30, 2026. The position became open when Willie Phillips resigned April 22.

LaCerte is the principal White House liaison and a senior adviser to the director of the Office of Personnel Management. Before joining the Trump administration, he was an attorney at Baker Botts. He was among hundreds of contributors to the Heritage Foundation's *Project 2025*, a road map for advancing conservative principles.

LaCerte served in the Marine Corps and is a graduate of *Nicholls State University* and Louisiana State University's *Paul M. Hebert Law Center*. He *fought criticism* of his time at the Louisiana Department of Veterans Affairs, which was marred by *controversy*. He also served with the U.S. Chemical Safety and Hazard Investigation Board.

According to his LinkedIn profile, LaCerte doesn't have the typical energy regulatory background of most FERC nominees. But in his last two years at Baker Botts, he specialized in "Energy Litigation/Environmental, Safety, Incident Response (ESIR)." (See his *full resume*.)

In June, the White House nominated Laura Swett to replace Chair Mark Christie, whose term is expiring. (See *Trump Replacing FERC Chair Christie with Laura Swett*.) If the nominations of Swett and LaCerte are confirmed by the Senate, FERC would have a Republican majority of commissioners.

David LaCerte | *Sternberg, Naccari & White*

Why This Matters

If LaCerte and fellow nominee Laura Swett are confirmed by the Senate, the Republicans will have a 3-2 majority on the commission.

POLITICO first reported the pending nomination July 15. Reaction was swift to the official nomination July 17.

Advanced Energy United issued the following statement from Managing Director Caitlin Marquis:

"As LaCerte goes through the confirmation process, we hope senators focus on the importance of competition, innovation and regulatory certainty when making their decision. Maintaining FERC's mission of ensuring a reliable, safe, secure and economically efficient energy system requires an independent body able to set appropriate regulatory market rules that promote confidence in the system and investment from energy resource providers."

Americans for a Clean Energy Grid Executive Director Christina Hayes congratulated LaCerte on the nomination. "As a bipartisan coalition of transmission policy advocates, we look forward to engaging with LaCerte as he approaches important issues before the commission related to transmission's role in the American energy dominance agenda through a reliable, affordable and resilient energy grid."

The White House also nominated *Arthur Graham*, a commissioner on the Florida Public Service Commission, to be on the Board of Directors of the Tennessee Valley Authority for the remainder of the term expiring May 18, 2026. Graham is a member of the National Association of Regulatory Utility Commissioners and served on the Jacksonville City Council. ■

FERC Faces Challenge in Balancing Executive Order and Legal Requirements

By James Downing

FERC is working to comply with an *executive order* from President Donald Trump requiring a review of all regulations it's issued under its major governing statutes. The commission's former general counsel warned it could be a boondoggle if handled incorrectly.

The order directs FERC and other energy agencies to include sunset provisions in its regulations, to the extent permitted by law. That would require FERC to reexamine them periodically or allow them to lapse, said Matt Christiansen, who was general counsel at FERC during the Biden administration and now is a partner at Wilson Sonsini Goodrich & Rosati.

"The CFR [Code of Federal Regulations] that pertains to FERC is like three or four inches thick," Christiansen said in an interview with *RTO Insider*. "It's at least 1,000 pages. So, we're talking about a lot of regulations that are potentially subject to this order. That means FERC staff has to spend a huge amount of time determining what would stay, what would go, what would happen to the industry and what would need to follow on if certain regulations are removed."

That includes fundamental rules that regulate the power industry such as allowing wholesale transactions using market-based rates.

"If the market-based regulations just disappear, it's not clear what would fill that vacuum and what would happen to regulated entities," he said.

FERC headquarters in D.C. | © RTO Insider

Why This Matters

FERC has 10 weeks to comply with an executive order that seeks to add sunset clauses to energy regulations, and if it gets the process wrong, it could gum up the works at the agency.

The U.S. Code is more than 60,000 pages and "unelected agency officials" wrote most of the legally binding rules, which often stretch the statutory provisions beyond what Congress enacted, said the executive order called "Zero-Based Regulatory Budgeting to Unleash American Energy."

"In particular, the previous administration added more pages to the *Federal Register* than any other in history, with the result that the Code of Federal Regulations now approaches a staggering 200,000 pages," the order said. "These regulations linger in such volume that serious reexamination seldom occurs. This regime of governance-by-regulator has imposed particularly severe costs on energy production, where innovation is critical. The net result is an energy landscape perpetually trapped in the 1970s."

Another big challenge to implementing the order is the Administrative Procedure Act (APA), which under Supreme Court precedent requires agencies to use the same procedures to amend a regulation that they used to enact it, Christiansen said.

"FERC uses notice-and-comment rulemaking to amend the CFR, which entails an opportunity to be heard on every aspect of every provision that's added or removed from the CFR," he added. "Then FERC, as part of its reasoned decision-making obligations under the Administrative Procedure Act, owes a non-arbitrary, non-capricious response to all those comments, which is a huge amount of work. I don't think you can just

Continued on page 8

CATF Report Argues for 'No-regrets' Approaches to Meet Demand Growth

By James Downing

The power industry can meet growing demand in a timely and cost-effective way by deploying commercially available new technologies to increase the use of the existing grid and proactively planning for new infrastructure, a new *report* from the Clean Air Task Force said.

The "Optimizing Grid Infrastructure and Proactive Planning to Support Load Growth and Public Policy Goals" report, prepared for CATF by The Brattle Group, highlights how to deal with demand growth from data centers, reshoring manufacturing and electrification.

"By mobilizing demand-side flexibility, increasing the utilization of the existing grid and recognizing uncertain future needs through proactive planning, utilities and other grid operators can serve new loads while mitigating cost increases, thereby avoiding large bill increases for existing retail customers and protecting them from future risks," the report said.

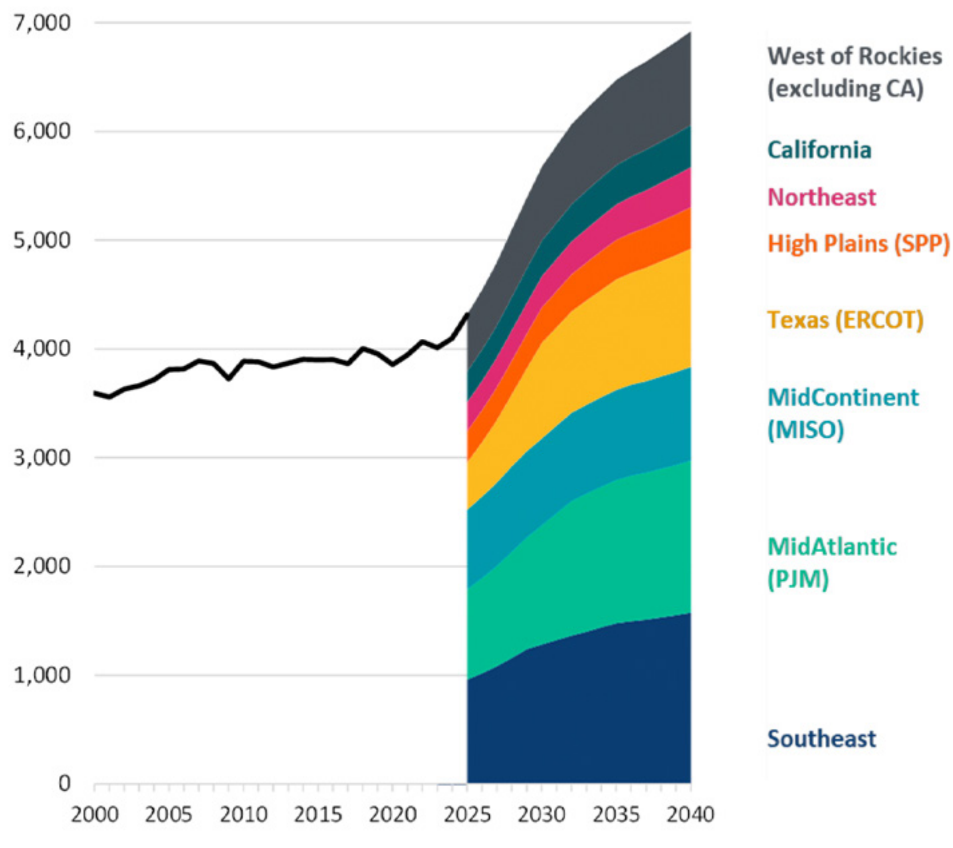
"Combining more efficient capital utilization with more proactive planning thus offers a win-win proposition that protects customers, serves new loads more quickly, benefits utilities and grid operators, and supports a wide range of public policy goals for clean energy and economic development," it said.

Demand growth has come back at a time of stressed supply chains, compounded by long interconnection queues and other factors contributing to a slowdown in the speed and scale of deploying new resources, CATF Electricity Director Kasparas Spokas said in an interview.

"We hope this report serves as a little bit of a menu of options of underutilized, but effectively no-regrets solutions that policymakers can evaluate and assess and hopefully adopt to both grow load while minimizing emissions and cost as much as possible," Spokas added. "And so, the goal really here was to highlight ... some of the near-term, no-regrets solutions that even if demand, which is highly uncertain, were not to materialize, would still be beneficial for ratepayers."

Why This Matters

CATF's timely report covers the biggest issue facing the power industry: how to meet growing demand reliably and affordably while complying with other policy needs.



The Brattle Group produced this graph for the report, which breaks down demand growth by region through 2040 by using ISO/RTO and utility forecasts. | *The Brattle Group*

The paper offers actionable recommendations for grid planners, but it does not cover the full scope of potential reforms that could be needed under the new demand paradigm, such as changes to wholesale power markets or technology innovations that might become commercially viable.

The pressure from demand is most acute with large loads such as hyperscale data centers and advanced manufacturing facilities because they often require access to vast amounts of reliable electricity and can start operating in a few years, while installing new infrastructure can take decades.

Some of the quicker ways to help manage that rapid demand growth include use of demand-side resources, grid-enhancing technologies and advanced transmission technologies, as well as taking advantage of upsizing opportunities when power lines are refurbished and facilitating interregional trade, the report said.

"Regulators and advocates just have to be very disciplined about requiring planners to effectively evaluate some of these [virtual power plant] demand-side solutions and advanced transmission solutions before committing to new buildout," Spokas said.

'Political Feasibility'

Policymakers should also establish and

expand efficiency and bill assistance programs for low-income customers and extend demand-side management to those customer classes. Another option is to establish rules that ensure customers with large loads don't end up imposing stranded costs and financial risks on other customers, the report said.

"I think that there's a lot of very acute and near-term political pressure that policymakers and legislators and others are feeling with regard to increases in customer prices for electricity, increases in utility bills," Nicole Pavia, CATF's director for clean energy infrastructure, said in an interview.

"We think that the political feasibility of implementing a broad suite of solutions kind of depends on gaining and maintaining political will for the energy transition," Pavia said. "A lot of that has to do with how consumers feel about rates and if affordability is top of mind. And, so, we think some of the measures around affordability can help reduce the political pressure in terms of the increasing rates and utility bills."

Transmitting energy more efficiently, speeding up queues and addressing affordability concerns will help, but the power system will eventually need new generation and transmission. Those investments can be assisted by facilitating customer-sponsored generation investments and procurements, and collocating generation and load in "energy parks."

Planning and procurement process should pick the flexible, least-regrets solutions and, where needed, attract new investments in a timely manner. Load forecasts can be improved, clean energy development can be sped up by picking zones that can be connected proactively with transmission and deliberately planning the distribution system to more cost-effectively manage load growth.

The return of demand growth has also increased interest in developing new natural gas-fired power plants around the country.

"There are a lot of low-cost, no-regrets solutions that need to be considered before you get to the point of building a new gas plant," Spokas said. "Once you get to that point as well, you need to consider the life of that asset."

Spokas thinks there's "a lot of talk" about future gas-fired plants being built as "hydrogen-ready" without much consideration about the investments needed to make them so.

"Where will the hydrogen come from? What will be the cost? So, I just think we all need to be very disciplined about what it takes to get to the point of saying, yes, a new gas plant is the solution," he said. ■

FERC Faces Challenge in Balancing Executive Order and Legal Requirements

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insert a sunset clause and stop enforcing those provisions or [remove] them altogether."

That's potentially a huge task for an agency that has lost staff and is dealing with a federal hiring freeze. Christiansen said FERC already was understaffed, compared to its growing responsibilities, under the Biden administration.

"I think adding such a big task as the EO at least seems to contemplate on its face would be really taxing on staff and could complicate FERC efforts to do some of its bread-and-butter statutory requirements," Christiansen said.

Christiansen said that there are regulations that could be streamlined, but FERC needs to get the process correct so it doesn't lead to extended litigation. Chair Mark Christie said the same thing in his press conference following the April open meeting just after the order was released.

"I think the idea of a regulatory house cleaning where you look at all your regulations is a very, very good idea," Christie said. "We're already in the process of looking at — for example, we're starting with regulations that were proposed that never got a final vote. They're sort of like zombie proposals that somebody at one time thought was a good idea. They got them out as a NOPR [Notice of Proposed Rulemaking], but they just sort of have been there for years."

Christie was describing proposals that never advance to a final rule because of leadership changes or changing priorities of the chair. But when it comes to rules that actually are finalized, the APA needs to be followed.

"You've got to follow it. And whatever we do, I want it to be effective. And I want it to stand up in court, because losing in court is not something I like to do," Christie said in April. "I want to win in court."

E&E News by POLITICO published a *story* on the executive order and got hold of a document circulating among commissioners that offers a potential response. However, FERC votes publicly and, especially with a looming leadership change at the agency with a new chair awaiting confirmation, much could change by the White House order's deadline of Sept. 30.

Executive orders can have short shelf lives depending on who wins the next election. If this one were to stay in place, it would require regular reviews of major FERC rules such as Order 888, which set up the open access transmission rules, and other foundational orders. Those rules have helped to establish the entire market-based regulatory structure that governs most of the power industry.

"There might be pockets of the industry that are OK with big changes, but I think on the whole the industry would prefer stability rather than the upheaval that I think this rule at least contemplates," Christiansen said. There are strategies that FERC, if so inclined, "could employ to mitigate some of that uncertainty." ■

Industry Experts Find Faults in DOE's Resource Adequacy Analysis

By James Downing

With over a week to digest it, grid planning experts in interviews said that the U.S. Department of Energy's recent *report* on grid reliability overestimates demand growth and underestimates likely supply additions with the goal of preventing power plant retirements. (See *DOE Reliability Report Argues Changes Required to Avoid Outages Past 2030*.)

The report includes 50 GW of data centers, which likely exceeds the supply of chips that would be needed to build them, Grid Strategies Vice President Michael Goggin said. (See *Doubt Cast from Different Angle on Data Center Load Demand*.)

"They also assume 51 GW of non-data center load growth, and that's pretty high, much higher than other projections that are out there, and particularly after the recent bill gutted incentives for electrification as well as for cleantech manufacturing in this country," Goggin said.

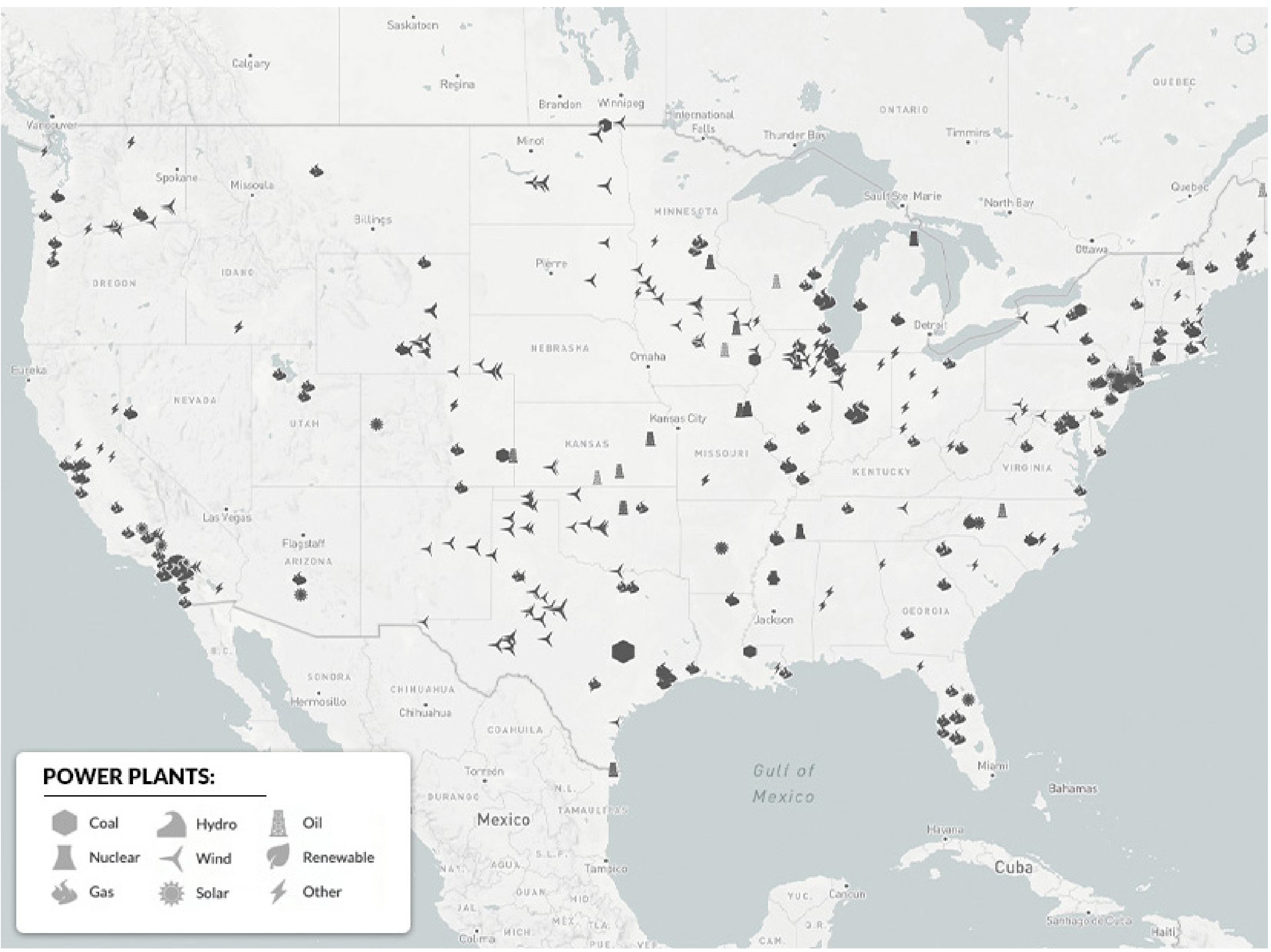
A DOE spokesperson said its load growth assumptions are based on NERC's Interregional Transfer Capability Study, with the addition of 50 GW of data center load picked as a midpoint from 2024 studies by the Electric Power Research Institute and the Lawrence Berkeley National Laboratory.

"Using a single planning midpoint addresses concerns of double counting and enables consistent load allocation across national transmission and resource adequacy models," the spokesperson said.

The report's prediction of 104 GW in generator retirements comes from NERC's

Why This Matters

DOE's recent resource adequacy report appears to be justification for keeping more existing power plants online.



A map using Yes Energy data showing recent power plant retirements. The DOE report argues that retirements need to be curtailed going forward to preserve reliability. | *Yes Energy*

Long-Term Reliability Assessment released in December and the Energy Information Administration's Annual Energy Outlook earlier this year. Both assumed that EPA regulations such as the greenhouse gas rules under Clean Air Act Section 111(d), which the Trump administration is actively working to overturn, will stay in place, Goggin said.

It also assumes additions of 20 GW of natural gas, 31 GW of four-hour batteries, 124 GW of new solar and 32 GW of new wind. It based them on NERC's projections of "Tier 1" assets — those in development most likely to be completed. But Goggin and others said that more capacity than that will be built by 2030.

"It also doesn't appear to account for the contributions of renewables to providing output during peak demand periods," Goggin said. "Wind and solar — solar more in the summer, wind more in the winter — provide dependable capacity value, just like other resources."

Overall, it seems like the report assumes that markets and states' integrated resource plans are not going to respond to load growth in the next five years beyond what is already in place, GridLab Executive Director Ric O'Connell said.

"It assumes NERC Tier 1 capacity additions, which is basically, as the report says, projects built in 2025 that are going to come online in the next two years," O'Connell said. "And, so, it essentially assumes that nothing's going to get built in 2027, 2028, 2029 and 2030, which is just not realistic."

A DOE spokesperson said the report's use of Tier 1 generation additions was grounded in reliability planning principles.

"DOE aimed to model a conservative yet realistic baseline. This approach is consistent with how NERC and planning authorities assess near-term reliability risks," they said. "While we recognize that many additional resources are advancing through utility IRPs and interconnection queues, we also note that there is considerable risk and supply chain delays when it comes to dispatchable generation with lead times in many cases as far out as 2030."

Even before the report came out, it was clear that the administration was focused on keeping old fossil fuel power plants online.

"They're retiring for a reason," O'Connell said. "They're uneconomic. They're old. And instead of thinking about building new, they're thinking that the only way to save the grid is to keep old stuff online. And I just think that's not really what most utilities and markets are thinking about."

PJM, MISO and SPP all have enacted rule changes to speed up new capacity additions, while utilities outside of the markets are actively addressing load growth through state regulations, he added.

"I think that's one of the things the report also misses … [the] self-correcting, inherent nature of both power markets as well as the regulatory constructs … around resource adequacy," Goggin said.

Higher prices from narrowing reserve margins are helping to bring new resources online and keep existing power plants that would have otherwise retired, he added. Vertically integrated utilities have their own mechanism addressing the same issue with state oversight and IRPs.

"State commissioners are certainly aware of the load growth and are making plans accordingly," Goggin said.

O'Connell said that ultimately, the answer to DOE's concerns is to get new resources online.

"We've got terawatts of capacity sitting in interconnection queues that haven't been coming online," he said. "Let's get that capacity online. Let's focus on streamlining the interconnection process, building new transmission, getting permitting reform right — clear the roadblocks for getting new capacity online. I feel like that the administration's answer — 'Let's just keep these 60-year-old plants online' — is just not the right answer."

What Will DOE Do with its Report?

"It was fairly underwhelming," Advanced Energy United's Mike Haugh said. "It didn't give any recommendations. It felt like the whole idea of this is a setup to basically issue more of the [Federal Power Act Section] 202(c) emergency filings."

DOE recently used its power under the section to order the Campbell coal plant in Michigan and the Eddystone plant in Pennsylvania, which can burn natural gas or oil, to remain online. The Campbell order is being appealed. (See *Order to Keep Campbell Plant Running Challenged at DOE and FERC*.)

The report includes different scenarios, but the one with the highest reliability has no power plants closing for the next five years, which is why Haugh thinks DOE could use it to issue more such orders. That could happen with the Campbell and Eddystone plants because 202(c) orders are limited to 90 days.

Demand growth is contributing to tighter reserve margins around the country, which in organized markets are leading to higher prices that send the signal that more power plants are needed, but it is running into the fact that new plants take time to build.

"There's a little bit of a lag," Haugh said. "But it should incentivize some of these units to stay open a little bit longer. The problem is, some of these are so inefficient and they're getting the capacity prices. … They're not actually running the plant very often."

So, while the natural market reaction will be to keep some power plants running longer than they otherwise would, others are too old and inefficient to bring in enough energy market revenue to stay open, and it will make economic sense to shut them down even with higher prices, he added.

The solution to the issue is clearing out the interconnection queues, Haugh said, which FERC and the industry were already working on before the new wave of demand growth came to dominate planning efforts. But that can still take up to five years, which is a snag in this whole process.

"You have projects that are ready to put steel on the ground," Haugh said. "And you can get these combined advanced resources that can be built a lot faster than a gas plant."

The industry already has regulatory mechanisms in place that have been working, and continue to work, to reliably meet the growing levels of demand, said Ari Peskoe, director of Harvard Law School's Electricity Law Initiative.

"DOE has never played this role before, and it doesn't need to try to play this role now, as sort of a master centralized planner," Peskoe said. "It was sort of ironic from an apolitical faction that has historically kind of respected states' rights on some of these issues."

Peskoe noted that the report has a major disclaimer under the "Acknowledgments" section saying its analysis "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level," where grid planners have access to better data.

DOE's spokesperson explained that point further, saying: "The intent of the report is to complement, not override, the more granular, region-specific planning processes that incorporate a broader range of resources."

"The bottom line is that the DOE team that wrote this paper acknowledges that its usefulness is very limited, and it should not supplant what happens at the regional level," Peskoe said. "Because the utilities, RTOs, states and other entities involved in those decisions have better, more detailed information. So, I think that's the most important takeaway from this paper."

DOE's main tool for addressing resource adequacy is Section 202(c), but its impact is limited to just 90 days and specific plants. The department could also try to get FERC to make some rule changes to stem retirements as it did in President Donald Trump's first term, but that is just speculation, Peskoe said. And its main ability is to analyze the issues, which contributes to understanding the problem and developing solutions.

"If you look at the Biden administration, there was a lot of focus on transmission, and DOE put out a few reports about the country's transmission needs, but they put those reports out after years of work, detailed consultation with industry and affected parties, and they were carefully done reports, whether you agree with them or not," Peskoe said. "This was done in 90 days."

Americans for a Clean Energy Grid Director Christina Hayes praised DOE for taking on the issue of load growth, which has dominated industry discussions for the last 18 months in part because of the uncertainty about how much of potential data center load will materialize.

"Generally, the way that this paper looks at the big challenges ahead of us is positive," Hayes said. "What concerns me is that it tends to look backwards to the solutions. So, it's thinking about it in terms of plants that are on the system, rather than how to plan going forward."

That new planning will involve new generation coming onto the system, but it will also require more transmission to move power around a bigger power system. Winning the "AI race" is a bipartisan goal, and Hayes noted that the U.S.' competitors are investing in their grids.

"I think there was a statistic to something like in 2022, China invested $168 billion in their grid," Hayes said. "The United States invested $22 billion in its transmission system. So, just on an apples-to-apples investment in the wires needed to support all of this new load and all of the new generation, we are far behind."

Infrastructure investment is starting to ramp up, Congress could take another crack at permitting legislation in Trump's term after the Manchin-Barrasso bill failed to advance last year, and some of the regions are moving forward with more transmission investment.

"We're seeing it on the ground, with 765-kV lines being proposed in Texas to support the oil and gas industry and their needs for power," Hayes said. "SPP, PJM and MISO are all looking at 765-kV lines to help support their greater electrification needs as well. So, we're seeing the region start to move on it, not because it's a partisan idea, but because it's a good idea."

Lines at 765 kV have been rarely used in the U.S. so far, but they can help move more power and can avoid building out multiple lines at lower voltages. Another option for getting more electrons around is to use advanced conductors at lower voltages, Hayes said. ■

Report Calls U.S. Transmission Buildout Inadequate

Anticipated Load Growth Requires Thousands of New Miles per Year, Authors Say

By John Cropley

A *new study warns* that the U.S. is not building anywhere near enough high-voltage transmission to support the anticipated needs of the evolving economy.

Americans for a Clean Energy Grid and Grid Strategies said July 21 that *just 322 miles of lines* rated at 345 kV or greater were completed in 2024, the third-lowest total in the past 15 years.

This creates potential stress for critical sectors whose electricity needs are growing, they said, such as artificial intelligence, computer chip fabrication and advanced manufacturing.

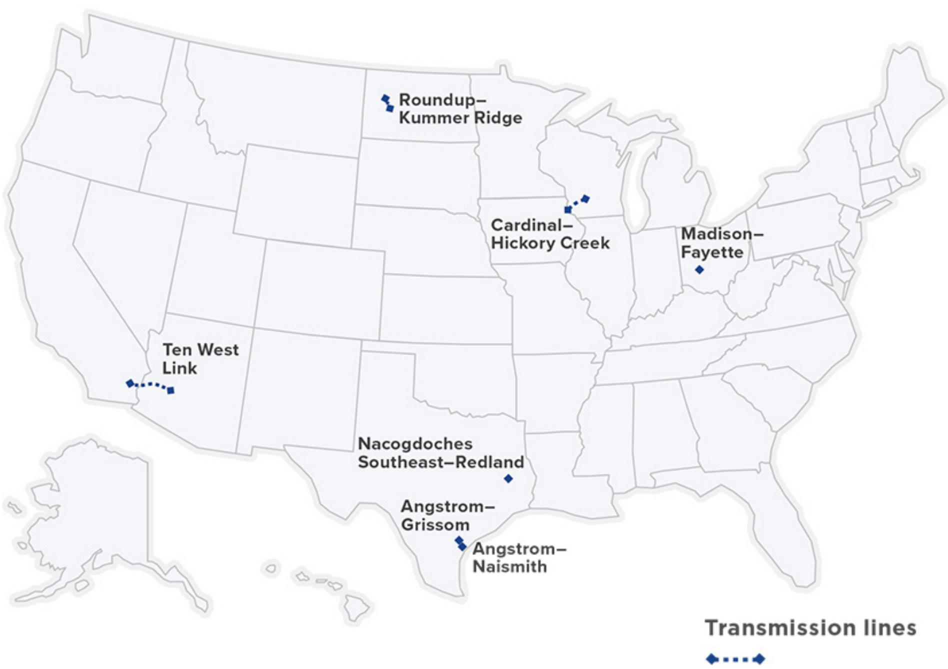
"We're seeing a serious mismatch between where we are and where we need to be," Christina Hayes, executive director of Americans for a Clean Energy Grid, said in announcing the report.

The two organizations called for ambitious multiregional transmission planning, as well as permitting reform.

"We know that thousands of miles of transmission can be built each year because in 2013 we did it, with California, Texas, the Southwest Power Pool and Midcontinent Independent System Operator all building hundreds of miles," Grid Strategies President Rob Gramlich said in a news release.

The U.S. Department of Energy in October 2024 addressed the issue with release of its *National Transmission Planning Study*. (See *DOE Funding 4 Large Tx Projects, Releases National Tx Planning Study*.) That study found that under various scenarios, the transmission network in the contiguous United States would need to be 2.1 to 3.5 times larger in 2050 than in 2020.

The 2.1x model would imply an addition of roughly 5,000 miles a year, the ACEG/GS report states. The only year in the study period that approached this was 2013, when approximately 4,000 miles of 345-kV and 500-kV lines were completed.



A handful of U.S. projects rated at 345 kV or greater were completed in 2024. | *Grid Strategies*

Why This Matters

Anticipated demand growth could be crimped by inadequate transmission infrastructure.

As an added benefit, the report noted, high-voltage lines are more cost-effective per megawatt and enhance resource adequacy by allowing capacity sharing across regional boundaries at times of grid stress.

The *Interregional Transfer Capability Study* that NERC filed in November 2024 recommended 35 GW of such capacity be added. (See *NERC Releases Final ITCS Draft Installments*.)

The ACEG/GS report notes that significantly more miles of natural gas pipelines than high-voltage transmission have been built in the past five years, and notes that no siting authority for power lines exists that is comparable to FERC's authority to site interstate gas lines.

Looking ahead, the report cites NERC data indicating 7,098 miles of lines greater than 345 kV under construction or planned through 2032 nationwide. And multiple regions are beginning to plan new 765-kV lines as higher-capacity corridors that move energy efficiently over long distances.

The ACEG/GS report concludes with the assertion that federal leadership in adopting the requirements of FERC Order 1920 now must be matched, and strongly, by regional implementation.

"Planners should treat Order No. 1920 as a floor, not a ceiling, building on its foundation for ambitious, proactive and multi-value regional transmission planning and cost allocation," the authors wrote. "In parallel, permitting reforms, targeted funding and state-federal collaboration can help ensure that projects move from planning phases to steel in the ground." ■

California Pathways Bill Delayed After Organizations Withdraw Support

By Henrik Nilsson

Why This Matters

The delayed hearing showcases the difficulties in drafting a law to create an independent RO that can balance California's interests with those of the rest of the West.

The author behind the bill that would allow CAISO to relinquish market governance to an independent "regional organization" (RO) delayed a hearing scheduled for July 16 after several organizations withdrew support for the proposed legislation.

SB 540, which passed in the California State Senate in June, was set for a first hearing in the State Assembly's Utilities and Energy Committee but was delayed until after the Legislature's summer break at the request of the bill's author, Sen. Josh Becker (D). (See *'Pathways' Bill Passes California Senate on 36-0 Vote*.)

SB 540 is part of the West-Wide Governance Pathways Initiative, an effort to create an independent RO to govern CAISO's Western Energy Imbalance Market and the soon-to-be-launched Extended Day-Ahead Market (EDAM). The effort aims to assuage concerns that the ISO — whose Board of Governors are appointed by California's governor — would act solely in the state's interest.

"The hearing was delayed with the support of the Senate and Assembly in order to have more time to iron out some details with the bill," Becker's press secretary, Charles Lawlor, told *RTO Insider*. "There is a huge, diverse coalition behind this bill. Conversations are active and ongoing. Our collective work is going to continue over the summer, and our goal is to move the legislation when we're back in August or September."

The move comes after 21 organizations, including the Environmental Defense Fund, PacifiCorp, Advanced Energy United, Amazon and Portland General Electric, changed their position to "oppose unless amended" on SB 540.

In a July 11 *letter*, the coalition said it opposed an amendment creating a new Regional Energy Market Oversight Council responsible for ensuring CAISO's participation in the regional energy market "serves the interests of the state." (See *Amended 'Pathways' Bill Boosts — and Complicates — Calif. Protections*.) The new council would be authorized to mandate withdrawal if those interests are compromised.

The California State Capitol in Sacramento | *Andre m, CC BY-SA 3.0, via Wikimedia Commons*

The coalition requested lawmakers remove the amendment, stating "the language in this section mandates the withdrawal of California entities from the market without exception or discretion, which is unacceptable."

"Market rules should be established based on facts, evidence and reliable data rather than fear," it wrote. "Even if withdrawal from the market were to be a prudent action, the mandated 120-day time frame is far too short and exposes California customers to serious reliability concerns, especially during periods of peak demand. Lastly, this language inadvertently asserts new [California Public Utilities Commission] jurisdiction over the state's publicly owned utilities, which is inappropriate and must be removed."

The coalition also argued lawmakers should remove revisions to California's Renewables Portfolio Standard Program and restrictions on a future market. It noted that some entities in Colorado, New Mexico and Idaho are at a crossroads on whether to join EDAM or SPP's Markets+.

"A smaller market for California means less cost savings, a less reliable grid and more climate-harming emissions," the coalition wrote.

Leah Rubin Shen, managing director at Advanced Energy United, commended the legislature for delaying the hearing to "ensure a productive path forward that preserves the widely supported core purpose of the bill: to facilitate California's participation in an expanded Western electricity market that provides robust state policy and consumer protections."

"The stakes are too high for California to walk away, especially as trading partners across the West weigh their options," Rubin Shen said. "Our shared vision remains clear: A strong regional electricity market that includes California will benefit the entire West by lowering costs, increasing reliability and delivering clean energy across the region. With continued commitment to passing a workable bill this year, we can achieve this goal."

Meanwhile, The Utility Reform Network (TURN) has changed its opposition to neutral after the bill was amended to address the organization's concerns that handing over governance to an RO could lead to increased federal intervention and undermine the state's clean energy goals. (See *California Lawmakers Seek to Trump-proof Pathways Initiative Bill*.)

"We need a very enhanced level of protection and guarantees that this entire experiment is voluntary and that the state of California has … full control over whether we would continue to participate over time," Matthew Freedman, staff attorney at TURN, said in an interview.

"We're mindful of the [Trump] administration's threat to force utilities throughout the West to subsidize legacy coal-fired generation that might be at risk of retirement, either under Section 202 of the Federal Power Act, or sent through some other mechanism that they invent," Freedman added. "We want to make sure that this regional market is not weaponized against California."

But Katelyn Roedner Sutter, California state director at the Environmental Defense Fund, said in an interview that fears the federal government will get involved are overblown, and that the bill makes clear California's existing climate or clean electricity policy will not change.

"None of this … is going to impact our renewable portfolio standard. And the same is true for other states. Other states get to uphold their existing policy as well," Roedner Sutter said.

"Where the real concern seems to come from is our relationship with FERC," Roedner Sutter noted. "And I think what people who raise that are not understanding is that CAISO [tariff revisions] … already have to go before FERC. That is the case right now; … that relationship does not change in any way with this bill or with California entities being part of a regional electricity market. So, nothing is actually changing about our relationship with FERC."

In separate statements released July 16, Gov. Newsom and Speaker Rivas both pointed to California's "opportunity" to improve electric reliability and affordability through increased regional coordination.

"We have the opportunity to expand regional power markets that help drive down energy costs and increase grid reliability — or we can turn our backs on this proven model and opt for higher costs and power outages," Newsom said. "The answer is clear: California must further enable continued cooperation with Western partners to secure our clean, reliable and affordable energy future. This is our best shot at lowering energy costs. Now the legislature must take action this year and deliver for the people of California."

"There is an urgent opportunity now — this year — to lower energy costs for California families and businesses, and we can help achieve this by expanding regional collaboration," Rivas said. "California must continue to lead and step up, or others will. We need to continue to facilitate cooperation with our Western neighbors through a voluntary, regional power market, because that is our best path toward driving-down costs and delivering a sustainable, reliable, affordable energy future for Californians. Let's get this done now." ■

CAISO Suggests CPUC Consider New Procurement Order for 2028

Projected Load Growth from 2028 to 2032 Greater than Previous Forecasts

By David Krause

CAISO is asking the California Public Utilities Commission to consider issuing a new procurement order to meet the state's electricity reliability needs from 2028 to 2032, citing significant forecasted load growth in those years.

New resources could be needed over the period in addition to existing procurement orders and load-serving entity resources, CAISO said in its *filing*.

The California Energy Commission's most recent demand forecast shows more load growth in those years than prior forecasts, CAISO said. CPUC's existing procurement orders provide resource requirements up to 2028.

Without explicit new procurement orders, LSEs might not schedule new development projects with sufficient lead time, risking capacity shortfalls when options to cure shortfalls may be limited, CAISO said.

"This outcome not only creates reliability concerns but could also result in a tight Resource Adequacy (RA) market and high RA prices in nearer-term years where new development is not an option," CAISO said.

CAISO asked CPUC to conduct a near-term needs assessment for 2028-2032, which could lead to a new procurement order issued as soon as the end of 2025, and develop a comprehensive Reliable and Clean Power Procurement Program (RCPPP) framework over a longer period.

Why This Matters

CPUC issues energy resource procurement orders to ensure California's grid can meet demand, and CAISO is now asking the agency to consider issuing a new procurement order because of potentially increasing demand in a few years.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CPUC's RCPPP *proposal*, published in April 2025, will develop long-term procurement requirements to allow LSEs to plan and implement their procurement of reliable and clean electric resources, the proposal says. CAISO supports the RCPPP goal to shift procurement away from emergency-based or "just in time" orders to more proactive procurement approaches, the ISO said in its filing.

CAISO is concerned about relying on the state's RA program to meet demand from 2028-2032. In previous CPUC decisions, the agency set planning reserve margin (PRM) levels and thus RA requirements below levels needed to meet a 0.1 loss of load expectation (LOLE) due to the risk of project delays and tight supply conditions, CAISO said in the filing.

Concerns about tight supply conditions persist, so CPUC should seek to minimize risks of supply shortfalls that result in the CPUC setting binding RA requirements below levels needed to meet a 0.1 LOLE reliability target, CAISO said.

CAISO's Cluster 14 interconnection queue contains significant potential new capacity, which could come online between 2028 and 2032 if CPUC determines new resources are needed, the ISO said. Many of these projects do not currently have power purchase agreements.

In 2021, Cluster 14 had 373 interconnection requests for a total of about 150,000 MW of proposed generating capacity, CAISO said in a 2021 *staff proposal*. In total, CAISO's generator interconnection queue contains 246,000 MW of potential generating capacity.

CAISO's 2024 peak demand was 48,323 MW. Even with robust procurement in the future, the potential generation available in the region exceeds demand by a significant margin, CAISO said in the proposal. ■

WRAP Task Force Explores Optimization Under Day-ahead Markets

By Henrik Nilsson

A new task force is examining how the Western Power Pool's Western Resource Adequacy Program (WRAP) can continue to operate efficiently under the new multimarket environment emerging in the West.

The WRAP Day-Ahead Market (DAM) Task Force held its second meeting July 17 and discussed some of the thorny issues that lie ahead for the resource adequacy program as CAISO and SPP prepare to launch their respective day-ahead markets. The group's members include entities like Bonneville Power Administration, Idaho Power, Portland General Electric and Powerex.

The purpose is to present a proposal aimed at enhancing WRAP's Operations Program to make it compatible with both SPP's Markets+ and CAISO's Extended Day-Ahead Market (EDAM). The task force is focusing on market optimization and changes to transmission requirements in WRAP's Southwest Region. (See *WRAP Members Align on Key Issues to Prioritize*.)

Representatives from WRAP participant organizations will chair the task force and formulate the proposal.

"WRAP was designed to work alongside all markets, as well as for participants who do not join a market," Michael O'Brien, WPP's senior policy engagement manager for the WRAP, told *RTO Insider*. "Much of WRAP's design was created before EDAM and Markets+ existed, though. This task force will look at if and how WRAP should be optimized to work alongside the markets. It's a chance to re-examine WRAP's Operations Program through the lens of the day-ahead markets to potentially identify any efficiencies and opportunities, such as taking advantage of market optimizations and internal connectivity."

Attendees of the July 17 meeting discussed issues such as data sharing between WRAP and market operators, handling holdback requirements, energy deployment and delivery, serving load in different markets and settlement pricing, among other potential challenges.

Why This Matters

WRAP was designed before Markets+ and EDAM and must now adapt to the multimarket environment that is developing in the West.

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The group will meet throughout the summer and fall to create a formal proposal that will go out for public comment and review by WRAP committees.

"If approved, the proposal could result in changes to business practice manuals or a potential FERC filing to make changes to the WRAP tariff," according to O'Brien. "While the task force will look at WRAP through the lens of the day-ahead markets, the scope of the task force is limited to modifications of WRAP only."

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 that they have secured their share of regional capacity needed for the upcoming season. Once WRAP enters its binding phase, participants with surplus 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. The binding phase is now expected to start in summer 2027. (See *WRAP Members Vote to Delay 'Binding' Phase to Summer 2027*.) ■

FERC Proposes to Eliminate Western 'Soft' Price Cap

Commission Says Regional Market Changes Negate Need for Anti-manipulation Policy

By Robert Mullin

FERC is moving to rescind the West-wide wholesale electricity price cap mechanism it instituted in 2002 in response to widespread price manipulation during the Western energy crisis of 2000/01, which resulted in rolling blackouts in California and famously led to prison sentences for leaders at energy trading company Enron.

The commission on July 14 opened a Section 206 proceeding to examine discontinuing its policy of maintaining a "soft" price cap for short-term electricity sales in the West to prevent the exercise of market power in areas outside CAISO (*EL10-56*).

Under the policy, any electricity sales exceeding the cap — currently set at $1,000/MWh — are subject to cost justification and refund upon review by FERC.

(While the policy is referred to as the "WECC soft price cap," the Western Electricity Coordinating Council is not involved with it or any regional market operations.)

"We preliminarily conclude that the requirement is no longer necessary to ensure just and reasonable rates and propose to eliminate it," the commission wrote in the order establishing the proceeding.

The proceeding comes a year after the D.C. Circuit Court of Appeals *ruled* the commission must apply the *Mobile-Sierra* doctrine when reconsidering a series of 2022 orders requiring electricity sellers to refund a portion of the high prices they earned during an August 2020 heat wave. (See *FERC Must Apply Mobile-Sierra to Western Soft Cap Refunds, Court Finds*.)

That case dealt with the surging prices associated with tight electricity supplies stemming from soaring temperatures over Aug. 18-19, 2020, as CAISO scrambled to prevent a repeat of the rolling blackouts it was forced to order Aug. 14-15 — the first such blackouts in California in 20 years.

During the heat wave, wholesale prices at Arizona's Palo Verde hub on the Intercontinental Exchange (ICE) hit records of $1,515/MWh on Aug. 18 and $1,750 on Aug. 19, compared with average prices that summer of $52/MWh, according to filings Southern California Edison and Pacific Gas and Electric submitted with FERC to contest the prices.

| Shutterstock

Why This Matters

FERC's proposal to eliminate the Western "soft" price cap signals that the commission thinks evolving market structures are adequate to protect the region from manipulation.

In 2022, FERC issued a series of decisions rejecting the justifications of sellers who sold electricity at those price levels during the event, having found that the ICE index prices reflected scarcity conditions and that the selling companies had failed to justify their premiums based on costs, as required under the soft cap framework.

The commission also rejected the sellers' contention that it must apply the *Mobile-Sierra* standard to the transactions because the contracts had been freely negotiated between the buyers and sellers and had not harmed the public interest.

The commission held that it had the authority to enforce the soft cap through refunds without conducting a *Mobile-Sierra* public-interest analysis because the soft cap was part of the sellers' filed rate — a finding the D.C. Circuit rejected when it said FERC was required to conduct such an analysis before ordering refunds.

"Even assuming that the soft-cap order was incorporated into sellers' tariffs and contracts, the commission did not displace the *Mobile-Sierra* presumption in the soft-cap order itself, and so that presumption continues to apply to the Sellers' contracts," the court found.

'Substantially Different' Market Landscape

In the July 14 order instituting the soft cap proceeding, the commission recounted the D.C. Circuit's findings and noted that, while FERC has over time revised the soft offer cap to reflect increases in CAISO's caps, it has never reassessed whether the framework is necessary to ensure just and reasonable rates in the West.

The commission wrote that the region's wholesale market landscape in 2025 is "substantially different than in 2002," when it created the soft cap.

"At that time, the commission sought to address the widespread effects of the Western energy crisis and establish robust, stable and competitive bulk power markets across CAISO and WECC outside of CAISO's footprint," it wrote. "As part of that effort, the commission recognized the interdependency of the CAISO and WECC markets and adopted the soft price cap outside of CAISO while the commission, CAISO, market participants and stakeholders pursued holistic reforms to CAISO's organized wholesale markets."

Regional market changes since then "call into question the need for" the soft cap, FERC said.

"In addition to the continued development and refinement of the CAISO market, the West now features widespread adoption of centralized real-time energy imbalance markets," the commission wrote, referring to CAISO's Western Energy Imbalance Market (WEIM) and SPP's Western Energy Imbalance Service (WEIS).

The commission also noted it has approved tariffs for two day-ahead markets expected to go live in the next two years — CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+ — as well as authorizing expansion of the SPP RTO footprint into the Western Interconnection.

"Notably, these real-time and day-ahead markets encompass transactions over the majority of the same spot markets to which the WECC soft price cap applies. These markets also include robust market monitoring and mitigation that addresses the potential exercise of market power in those constructs," FERC said, adding that market monitoring and mitigation in the more centralized markets "also has a disciplining effect on associated bilateral markets."

"Given these developments, we preliminarily conclude that the WECC soft price cap is no longer needed to discipline WECC spot market sales activity," the commission said.

The commission also pointed out that the Energy Policy Act of 2005 has given it "more robust legal authority and monitoring capabilities to address wholesale market misconduct" and greater authority to pursue allegations of price manipulation in its jurisdictional markets than it had when it established the soft cap in 2002.

Furthermore, the commission said it "preliminarily" concluded that the "filing burden" associated with the soft price cap "is no longer warranted, given the limited monitoring benefits that it provides." It said the requirement "imposes costs on market participants and the commission and creates uncertainty for individual transactions while those filings are pending review at the commission."

"Given the developments noted above, and the D.C. Circuit's clarification of how the currently effective soft cap operates, we question the benefit of requiring individual sellers to submit an informational filing for spot market transactions above the $1,000/MWh threshold simply to facilitate the commission's review of those sales through the *Mobile-Sierra* framework," FERC wrote. ■

Calif. Electric Reliability Outlook Strong, CEC Report Says

By David Krause

The Bottom Line

Grid reliability has been shaky in California over the past decade, but now the state is in a stronger position due to the installation of new energy resources over the past few years.

California should have plenty of electricity available to meet demand over the next few years, even during extreme weather events or if new energy resource installations are delayed, the California Energy Commission said in a new report.

The positive outlook is a change in flavor after difficulties over the past decade with rolling blackouts, emergency flex alerts, public safety power shutoffs and capacity shortages.

Now, the Golden State is expected to have more than 4,000 MW of surplus capacity this summer under normal conditions, while under an extreme shortage scenario, more than 700 MW of surplus will be available, the California Energy Resource and Reliability Outlook 2025 *report* says.

In 2024, California set "another record year for resource development — adding more than 6,800 MW of new capacity," the report says. More of these new resources started operating before the summer season compared with the prior four years, with more than 49% of the added capacity in 2024 operating before the start of summer, which "contributed greatly to supporting grid reliability during the heat waves in July and September" of 2024, the report says.

Much of the credit for the optimistic reliability outlook also goes to eight new transmission projects, including the TransWest Express project, the Greenlink project, the Gateway South and West projects and the Southwest Intertie project. Some of these projects are operating, while others are close to operation or under construction.

Tariff and Import Uncertainties

One reliability unknown going forward, however, is the effect that the Trump administration's recent tariffs could have on electricity infrastructure equipment. The CEC warned that new tariffs could have a major impact on electricity resources, such as circuit breakers, transformers, solar panels and battery storage systems. Tariffs on equipment might "significantly reshape market dynamics across the energy sector," the report says.

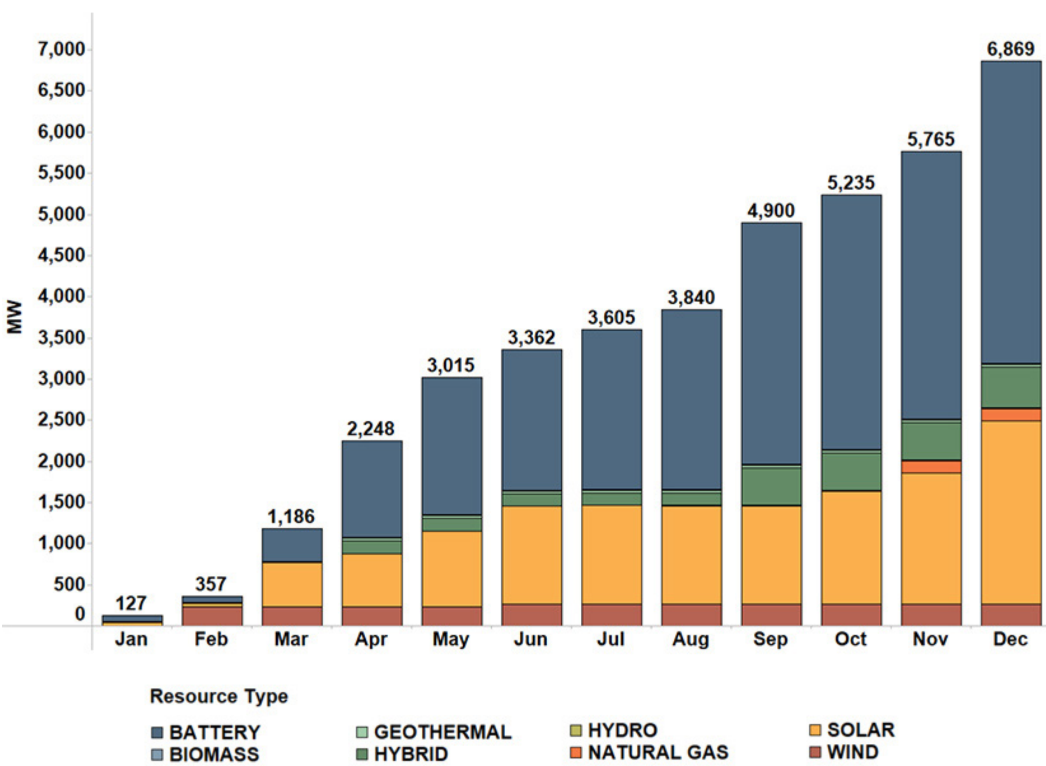
"For utilities and renewable energy developers, tariffs can delay project timelines, create uncertainty and increase installation costs, potentially delaying completion dates," the report says. "The impact varies widely depending on domestic manufacturing capacity — areas with robust local production might see minimal disruptions, while sectors reliant on specialized imported components could experience substantial price increases and supply shortages."

Over the past two years, California has also become less reliant on imported power. In 2023 and 2024, CAISO requested less imported electricity than in 2021 and 2022 due to the installation of new energy resources — mostly battery storage facilities — in the state.

But even so, California continues to be a net importer of power: It pulls about 29% of its electricity from outside the state, particularly in the evening when electricity demand is highest.

Import availability is also decreasing for California due to tightening supply West-wide, the report says. CAISO has a total import limit of 11,665 MW and 5,500 MW during resource adequacy risk hours.

Beyond 2030, California's grid can be "quite sensitive to a reduction in the resource build or a reduction in import availability," according to the report. Even if the state adds all of its planned new resources between 2025 and 2035, the grid will nonetheless remain dependent on its neighbors for resource adequacy, the report says. ■



Cumulative resource additions in 2024 in CAISO's region | *CAISO*

Calif. Lawmakers Seek More Accountability from CPUC

Senate Energy Committee also Hears Surplus Interconnection Bill

By Elaine Goodman

A California Senate committee has advanced a bill aimed at increasing transparency and accountability of the state's Public Utilities Commission, as consumers grow increasingly irate over utility rate hikes.

Assembly Bill 13 by Assemblymember Rhodesia Ransom (D) passed the Senate Energy, Utilities and Communications Committee July 15 on a 16-0 vote, with one abstention. The bill now heads to the Senate Appropriations Committee.

And with a July 18 deadline looming for legislative policy committees to move bills, the committee considered a number of additional bills. Those included Assembly Bill 1408, which aims to make better use of surplus interconnection service, the unused portion of interconnection capacity at a power generator's point of interconnection.

Geographic Diversity

AB 13 asks the governor and Senate to consider geographic diversity when selecting members of the California Public Utilities Commission. Currently, all five commissioners are from Northern California, in Pacific Gas and Electric territory, Ransom said.

The bill would require the CPUC to submit a report to the legislature within 15 days of issuing a decision in a ratemaking case, summarizing evidence used to support any rate increases and detailing the commission's rationale for its decision.

"We are often blindsided and confused about some of these rate-setting cases," Ransom told the committee. "And we want to have an ample opportunity to respond."

Why This Matters

AB 13 would help address concerns about the CPUC's lack of representation of Southern California and the Central Valley.

California Assemblymember Rhodesia Ransom, far right, presents AB 13 to the Senate Energy, Utilities and Communications Committee on July 15. | *California State Senate*

Under AB 13, the CPUC president would be required to discuss rate affordability and recent rate-making cases during annual appearances before legislative committees, which already are mandated.

And the CPUC would be required to include in its annual report to the legislature the number of cases in which it failed to issue a decision within the statutory deadline. The provision could apply pressure to resolve rate cases faster instead of allowing them to drag on for years, according to San Diego Gas & Electric, which supports the bill.

"There's no question in my mind that the PUC needs a little change in direction," said Sen. Jerry McNerney (D), who serves on the committee.

McNerney said he'd like to see more Central Valley representation on the CPUC as well as other state commissions. He'd also like the CPUC president to appear before lawmakers more than once a year.

District Representation?

An earlier version of AB 13 would have required four of the five commissioners to represent different zones within the state, based on the four State Board of Equalization districts. The fifth commissioner would be an at-large consumer advocate.

But instead of a requirement for geographic representation, a committee amendment asks the governor and Senate to consider geographic diversity when selecting commissioners.

In 2022, lawmakers passed a similar bill, *AB 1960*, which said the governor and Senate "should consider" regional diversity in choosing commissioners.

But Gov. Gavin Newsom vetoed it, calling it "unnecessary."

"There are other factors that must also be considered in making CPUC commissioner appointments, such as professional experience, knowledge and subject matter expertise, as well as diversity," Newsom said in his veto message.

"Further, I am already deeply committed to boards and commissions that represent California's diversity, including regional representation."

Surplus Interconnection Service

AB 1408 by Assemblymember Jacqui Irwin (D) pertains to surplus interconnection service.

The unused interconnection capacity creates an opportunity to add renewable energy resources or battery storage at or near fossil plants, proponents said. It also may encourage the use of federal clean energy tax credits that will expire soon.

Irwin cited as an example the Ormond Beach generating station in Oxnard, which has a "huge" transmission infrastructure but is used only as a backup power source.

"That's an example of an incredible opportunity to place renewable energy close by," she said.

AB 1408 would require CAISO to consider surplus interconnection service in its long-term transmission planning. It also would require utilities to evaluate and consider surplus interconnection options in their integrated resource plans.

The committee's final vote on the bill was 16-0, with one abstention.

The legislature begins its summer recess July 19, returning on Aug. 18. The last day for each house to pass bills is Sept. 12. ■

Large-scale Solar and Wind Hit with One-two Punch

Federal Policy, Local Resistance Create Major Clean Energy Barriers

By Elaine Goodman

As new solar and wind developments face hurdles due to changes in federal policy, the projects are also encountering growing resistance at the local level, according to speakers at a webinar.

"In most of the United States, it's very local government — counties or townships — that have the authority to decide whether these large-scale clean energy projects can move forward or not," said Dahvi Wilson, founder and president of consulting firm Siting Clean. "And increasingly, they are saying no."

Wilson was one of four panelists at a July 17 *webinar* on obstacles to energy infrastructure. The event was hosted by Resources for the Future, a nonprofit research institution.

At the heart of the local resistance is the feeling that utility-scale solar and wind projects are transforming rural landscapes, giving them an industrialized feel, Wilson said. But the opposition to projects frequently expands to arguments that "often aren't legitimate," Wilson said, such as claims that the projects will have health impacts, hurt property values or are part of the "green new scam."

Another factor in the growing local resistance is the transmission system's limited capacity, Wilson said. As a result, clean energy developers are flocking to places where they can get on the grid.

"It leads to a ton of pressure on those places," she said. "Suddenly, the resistance to this kind of development increases."

Mapping Restrictions

Panelist Robinson Meyer, founding executive editor of Heatmap News, said that following enactment of the federal budget reconciliation bill, called the One Big Beautiful Bill Act (OBBBA), clean energy adversaries will increasingly focus their efforts at the local level.

"That is where the big fights are coming for slowing down clean energy production," Meyer said.

Heatmap News surveyed counties across the country and found that 605 counties — accounting for about 17% of the land area of the continental U.S. — restrict solar or wind development in some way. The restrictions might be in the form of an outright ban, development requirements such as setbacks that make it nearly impossible to build, or moratoria that can be slapped on at will.

Wind and solar developers also identified local opposition as a significant barrier to clean energy projects in a January 2024 *report* by Lawrence Berkeley National Laboratory. (See *Reports Detail Causes, Impact of Local Opposition to Renewables*.)

Meyer said areas such as the Southwest have had a "relief valve" for building renewable projects on federal land, where county rules don't apply. But now even that relief valve is under fire from the Trump administration.

Under a new *directive* from the Department of the Interior, all decisions concerning wind and solar energy facilities must be reviewed by Interior Secretary Doug Burgum, including leases, rights-of-way, construction and operation plans, grants, consultations and biological opinions. Critics called the order a "shadow ban" on clean energy projects. (See *Interior Dept. Places Solar, Wind Under Close Review*.)

Some states, such as New York and Michigan, are addressing local resistance to solar and wind projects by adopting mechanisms to override the opposition.

So even though the 250-MW Mill Point Solar 1 proposal in Glen, N.Y., has polarized residents, locals are limited in their ability to fight back. (See *Rural Town Grapples with N.Y.'s Renewable Energy Vision*.)

"State preemptions of these rules can be quite effective," said Meyer, who noted there are more clean energy projects on the Michigan side of the Michigan-Ohio state line than on the Ohio side.

Tax Credit Clock Ticking

With the enactment of OBBBA, solar and wind developers now face a tight timeline for starting and finishing projects in order to qualify for sunsetting tax credits.

Investment and production tax credits will no longer be available for solar and wind facilities placed in service after Dec. 31, 2027 — unless construction starts by July 6, 2026, in which case the deadline for placing the project in service is extended. The dates are subject to Treasury Department guidance; an update to the guidance is expected by Aug. 18.

> **Why This Matters**
>
> With the looming expiration of federal tax credits for wind and solar development, a delay can spell the end of a project.

The tight tax-credit timeline means that opponents only need to delay a project to derail it, Wilson said.

"They don't even have to kill the project," she said. "They have to delay them maybe a year, to knock them out of being qualified."

Webinar panelist Rich Powell, CEO of the Clean Energy Buyers Association, said there could be a rush for developers to "commence construction" of solar or wind projects to meet the tax credit deadline. That might entail starting work on a new transformer or road, or meeting a spending threshold by purchasing solar panels, turbines or batteries.

"Which is painful from the buyer's perspective, because that's going to mean prices go up for all of these things … as people sort of rush to do that," Powell said.

Panelist Allison Clements, a former FERC commissioner who is now a partner at ASG, a consultant to the data center, cloud and real estate development industries, called the administration's actions "economically irrational."

"I couldn't have guessed in my most creative moment some of these things they're doing to slow things down. [Saying] 'I really hate this color of electron versus that color of electron,'" Clements said.

But Clements said given the "durable demand" expected over the next five to seven years due in part to computing needs and electrification, she still expects projects to proceed.

"Things will just be increasingly messy but continue to go forward," she said. ■

Canadian Utilities Push Action on Net-zero Goals, Tax Credits

Backlash over Law Fast-tracking Infrastructure Projects

By Rich Heidorn Jr.

Canada's utilities are encouraged by the country's new government but say legislation to fast-track high-priority infrastructure projects does not address needs for permitting relief and more flexible clean energy targets and investment tax credits.

The Building Canada Act (*Bill C-5*), approved in June, gives the federal government the ability to override some laws, regulations and environmental assessments for projects designated as in the national interest. The bill has sparked opposition and *litigation* from Indigenous groups.

"I think the view generally is C-5 sends a good message, but it does not address any of the fundamental issues that need to be addressed," Francis Bradley, CEO of trade group Electricity Canada, said during a presentation at IESO's Strategic Advisory Committee meeting July 16. Electricity Canada, formerly the Canadian Electricity Association, *represents* 42 generation, transmission and distribution companies in Canada's 10 provinces and three territories.

C-5 is expected to fast-track permitting for 10 to 12 projects.

"If your project is not on that list, what happens?" Bradley asked. "We have not addressed any of the fundamental challenges that we have with getting infrastructure built in the country. So, we haven't addressed the Clean Electricity Regulations [CERs]; we haven't addressed the *Fisheries Act*; we haven't addressed the *Impact Assessment Act*."

'Concierge' Approach

Julia Muggeridge, Electricity Canada's vice president of communications and sustainability, recalled a meeting with the new Major Projects Office — the hub of a "one project, one review" model to eliminate duplication between federal and provincial governments — shortly after the April 28 federal elections.

"It was a very positive meeting. … They said that there's going to be this concierge approach to [C-5] projects, but then there's going to be the second tranche of projects that will have less of a white-gloved approach, but they'll also be given their own process. We haven't seen that yet, but it was something that was introduced to us."

Why This Matters

Canada's electricity grid will need major infrastructure investments to handle a projected doubling in load over the next 25 years.

Muggeridge said some of her group's members are concerned over the speed with which the bill was approved and the lack of consultation with them in advance. "But I believe that's being rectified throughout the month of July. We're hoping for positive conversations over

Francis Bradley, CEO of trade group Electricity Canada (right), and Julia Muggeridge, vice president of communications and sustainability, presented at IESO's Strategic Advisory Committee meeting July 16. | *IESO* the next two weeks, but that's generally what I've been hearing from members who are excited and looking at how they can ensure their projects are on this list of 10 to 12."

Indigenous leaders, however, were not mollified by a meeting with Prime Minister Mark Carney on July 17, saying consulting First Nations after the legislation had passed was disrespectful.

The 2025 priorities that Electricity Canada will be presenting to the government in August will "look a lot like they did in 2024," with an emphasis on improving the country's competitiveness, Muggeridge said.

"It is too difficult to build in Canada," she said. In "the latest ranking with the [Organization for Economic Cooperation and Development], we were like 64th for permitting in the world."

The group says CERs' goal of an emissions-free electric grid by 2035 will harm affordability and reliability, with impacts most acute in Alberta, Saskatchewan, Ontario, Nova Scotia and New Brunswick.

It also is seeking to change investment tax credits to include intra-provincial transmission and revise the definition of eligible small modular nuclear reactors; extend timelines for full value credits from 2030 to 2035; and eliminate the requirement that provinces and territories commit to a net-zero grid by 2035.

'Startup Vibe'

Muggeridge said the new government has "a bit of a startup vibe."

"This happened with [Prime Minister Justin] Trudeau in 2015 … an excitement and an urgency. Ministries are being staffed with new young folks that are excited to meet with Electricity Canada. We're delighted with the engagement that we've had with the new government so far."

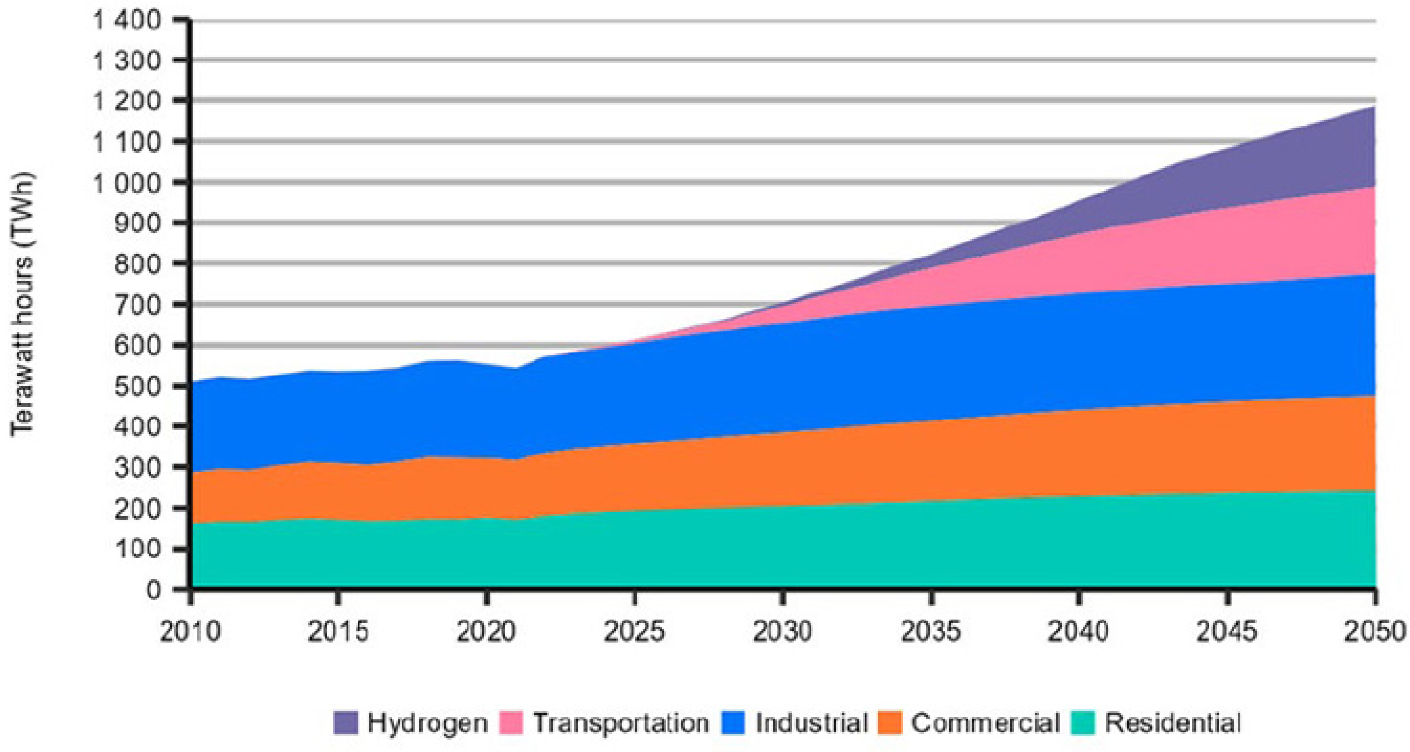
Bradley agreed. "Clearly, the tone is different. … Seven or eight months ago, nobody around the Cabinet table would even engage in a conversation about some of these topics. Now, those conversations are at least taking place. … Whether or not it actually results in in making it easier to get good projects moving forward remains to be seen.

"What we need more than anything else is … certainty so that those investments can happen," he added. "We'd like to remind people that we're not talking about investments that have a three-year lifespan or a five-year lifespan. We're talking about investments that that need to be able to stand up to the test of time for 20, 30, 40 years. These are generational investments that are required."

13 Systems

Bradley said Canada's electric regulations also are a challenge. "There is not that one electricity system in this country. There are 13 systems. And each of those systems — each province and territory — has constitutional authority over its own electricity regulation. And provincial autonomy often leads to resistance against federal initiatives, including, for example, net-zero targets or national infrastructure projects. In some jurisdictions, it's principally Crown-owned companies. In other jurisdictions, it's investor-owned companies. There's a different level of market access and market maturity.

"I will often hear from folks in the western Canadian context, talking about the interconnection between [British Columbia] and Alberta," he continued. "Why would one build more interconnection between these two jurisdictions when the current interconnection are not being maximized? Well, the current interconnection is not being maximized because there's a mismatch between the markets." ■



Canada's annual electricity demand is projected to at least double to 1,200 TWh by 2050. | *Electricity Canada*

IESO Planners Using 'Adaptive Pathways' to Address Load Growth Uncertainty

By Rich Heidorn Jr.

IESO planners are using "adaptive pathways" to account for uncertainty over future load growth, the ISO told stakeholders.

"It's not let's wait and see what happens and then … react to that, and … if there's a data center that pops up here, let's completely build the system around that," IESO planner Nikola Dimiskovski said in a July 16 *webinar* on planning for Greater Toronto Area (GTA) East.

"Adaptive planning is identifying in this region, what is the next logical step for expansion? What do we want the system to look like overall? … [We] develop a couple of different pathways for that, and then through iterative processes … every year, we can kind of revisit the plan in terms of where are we on this timeline."

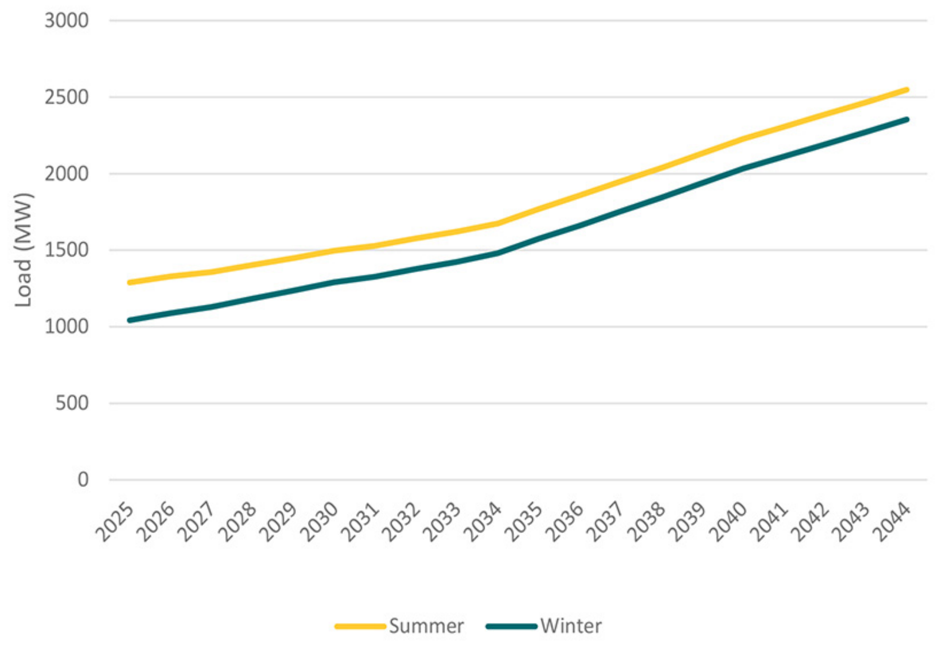
The ISO *predicts* electric demand in GTA East will increase by 98% in summer and 126% in winter by 2044 due to electrification and growth in residential, commercial and industrial loads. That's above the projection for all of Ontario, which is expected to see a 75% increase in demand by 2050.

The *GTA East Integrated Regional Resource Plan (IRRP)* is one of 11 regional plans IESO is developing, along with its *Central and South Bulk Study*, to deliver the increased power through wires and non-wires solutions. The infrastructure needed to address local electric system needs is planned by local distribution companies, which are the main sources for the province's demand forecasts.

IESO is considering several options for new transmission in GTA East, including an underwater cable, two overland options using existing corridors, and an underground line crossing the city, said Bev Nollert, director of transmission planning.

Why This Matters

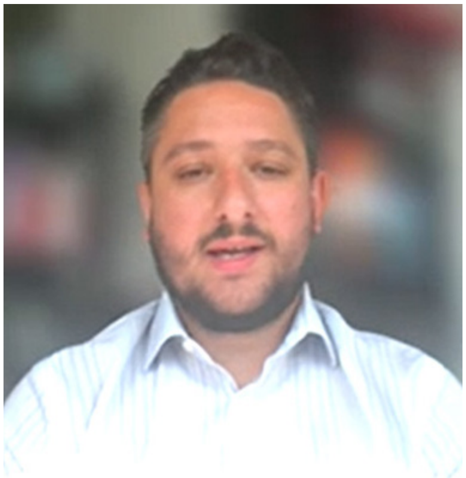
The ISO predicts Ontario's electric demand will increase by 75% by 2050, with larger increases in Toronto and Ottawa.



Demand in Greater Toronto Area East is projected to increase by 98% in summer and 126% in winter by 2044 from electrification and growth in residential, commercial and industrial loads. That's above the projection for all of Ontario, which is expected to see a 75% increase in demand by 2050. | *IESO*

Three Scenarios

The GTA East plan will consider three scenarios, including a reference case based on current trends and policies in electrification of transportation, space heating, industry and other areas, along with high- and low-demand scenarios bracketing the reference case.



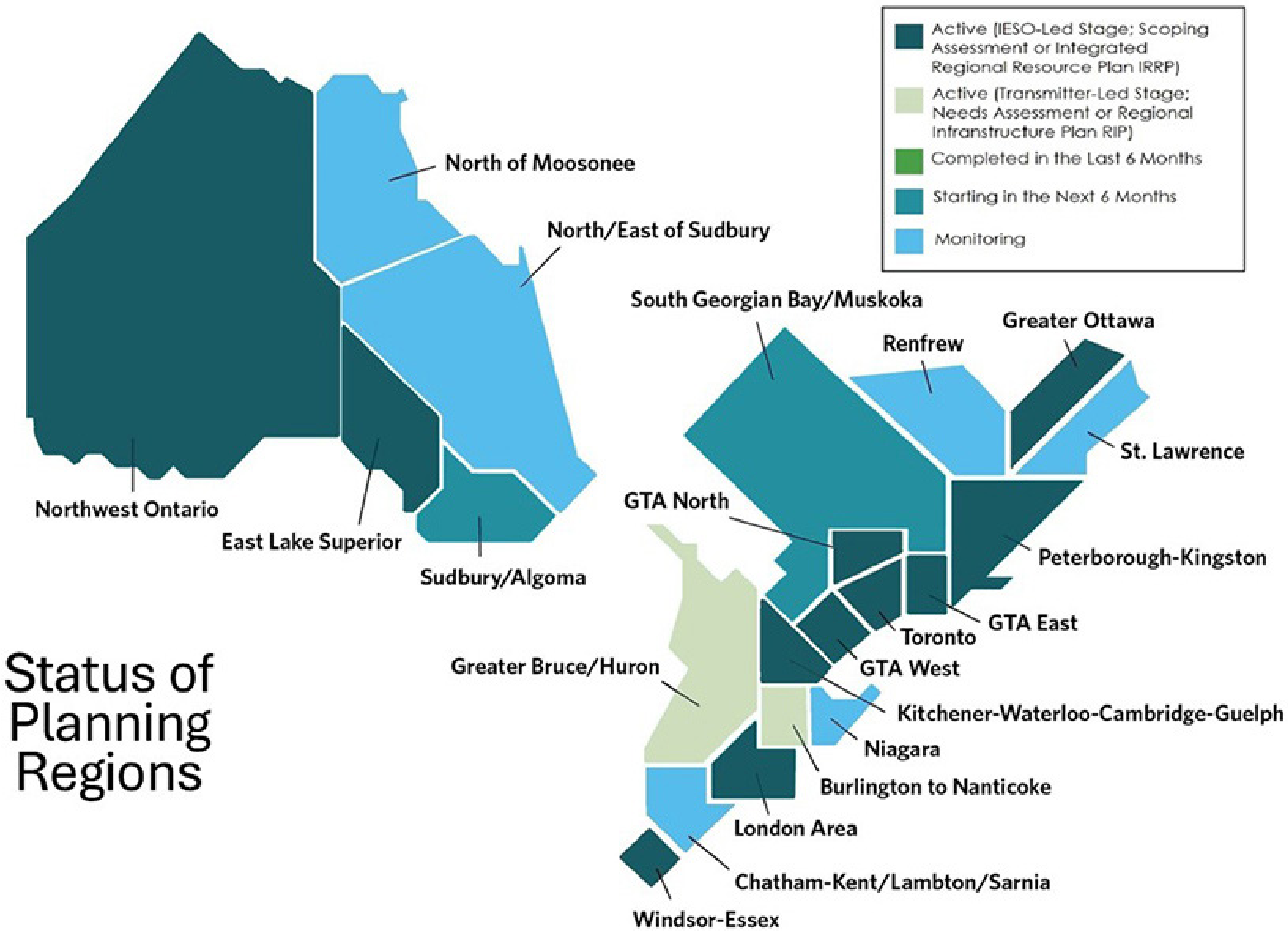
IESO planner Nikola Dimiskovski | *IESO*

IESO's recommendations will be driven mostly by the reference demand forecast, with the low and high forecasts used to "test the robustness of the plan, identify signposts to monitor forecast changes and contemplate additional actions required if lower or higher demand growth materializes," the ISO said.

Under adaptive pathways, planners calculate how much increased load would trigger the need for a new transmission line, Dimiskovski said. "Or instead of a new line … what would be the equivalent to a new line? That might be something like a 300-hectare wind farm with battery storage. So those are your two pathways. You can either build the solar panels and the wind and all those things, or you can build the lines. And then, of course, you can do kind of a hybrid of those two."

The result will be a "subway-style" map listing "no regret" investments, he said.

"You might think 2034 is really, really far away. But if this current system cannot



Status of regional planning projects | *IESO*

meet that load [in] 2034, that means we have to start building a transmission line about seven to eight years before that," he said. "Two years from now, we have to start building something if we think the load is going to come."

Uncertainty

Unlike other parts of Ontario, which are starting to shift to winter-peaking regions due to electric heating, GTA is projected to remain summer peaking, Dimiskovski said, adding, "I don't think we've 100% captured a full electrification of electric heating."

Dimiskovski mentioned uncertainty over load growth increases in the second half of IESO's 20-year projections. "In the first five to 10 years, we have a pretty good amount of certainty for what's going to come onto the system. So that's things like customer connections, large projects that you can see, community development plans, things like that. But then beyond the 10 years, governments change, new technologies come up, electrification is going to intensify."

Demand growth is predicted to become increasingly steep beyond the first 10 years. "Electrification is going to really start to manifest there," Dimiskovski said. "Whether it's 2044 or 2034 or 2064 or whatever it might be, eventually, it seems like the trend is that the lowest-hanging fruit of what can be electrified will be electrified."

Dimiskovski said he is more confident in projections for GTA than for Ottawa, where "we're seeing tripling or quadrupling of the load — so 3,000 additional megawatts."

What's Next

Written feedback on the GTA webinar should be emailed to engagement@ieso.ca by Aug. 6.

The ISO will share needs and "screened-in options" in the fourth quarter, with an analysis of the options in Q2 2026 and completion of the IRRP set for Q4 2026.

Incumbent transmission companies will lead development of wired solutions. "For non-wire solutions, implementation mechanisms for new resources and energy efficiency programs will be determined following plan publication," the ISO said. ■

IESO Capacity Market Rule Changes Advance

Rich Heidorn Jr.

IESO's Technical Panel approved measures to reduce unfulfilled capacity commitments and began discussion of proposed changes for how the ISO breaks ties in its annual auctions.

At its July 15 meeting, the panel approved by a voice vote *rule changes* to reduce unfulfilled capacity commitments by making it easier for participants to transfer their obligations and harder to buy them out. The vote recommends the IESO Board of Directors approve the changes at its meeting in August.

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

Unfulfilled obligations reduce "the capacity available to the IESO and distorts auction clearing price signals," the ISO says.

Under the changes, suppliers who fail to complete the registration process no longer would have the option of simply forfeiting their deposits and would be required to buy out their obligations. In addition, the buyout charge will increase from 30 to 50% of the obligation value.

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

Tie-break Rules

The TP also discussed a revised method for breaking capacity auction ties that the ISO has promised in time for the 2025 contest in November.

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

Under current rules, the ISO uses time stamps to select the bid submitted first, a method stakeholders have complained is inequitable. The new rules would create a multistep process IESO said will be fairer. (See *IESO Eyes New Tie-break Rules for November Capacity Auction*.)

The initial design proposed last September was to proportionally allocate capacity based on the offer amounts, said IESO Capacity Auction Supervisor Laura Zubyck.

"The feedback that we received from stakeholders was that there's a risk in that design that participants could inflate their offer amount in order to try to clear the largest amount possible," she said.

As a result, the ISO revised the rules to award an equal share in the first step and apply a proportional allocation in step two, based on what's left over from step one.

Zubyck said stakeholders have been "unanimous" that the proposed change is an improvement.

Michael Pohlod, director of energy markets for Voltus, a virtual power plant operator and DER platform, praised the ISO's movement on the issue, calling it a "a major concern."

But Forrest Pengra, director of strategic initiatives for Seguin Township, noted that the final solutions are not proportional to offers, citing one *example* in which one supplier would clear 100% of its offer, while two others receive 64 and 48% of theirs. "That, to me, doesn't seem as an equitable distribution," he said.

"You're not wrong in terms of how it's distributed," Zubyck responded. But she said the original plan to proportionally allocate in the first step based on the offer

Ontario Power Generation's Vladislav Urukov prompted a review of IESO's market rules and the Technical Panel's Terms of Reference for consistency. | *IESO*

Why This Matters

IESO says unfulfilled capacity obligations distort auction clearing price signals.

Step 1

- Divide the remaining available (tied) auction capacity by the number of auction offers involved in the tie.
- Round down to one decimal place and allot this equal share of auction capacity to participants (where possible).
- Offers can be flagged as "full" or "partial" by participants. Offers flagged "full" must be fully satisfied in step 1.

Step 2

- For auction capacity remaining after Step 1, allot a proportional share to each partial offer that was not fully satisfied in Step 1.

Step 3

- For auction capacity remaining after Step 2, allot by time stamp rank.

Proposed three-step capacity auction tie-break process | *IESO*

amounts created "the risk of offers being manipulated" to increase the amount cleared.

Pohlod said the original proposal created a "game theory problem."

"You have people wind up clearing more than they wanted because they thought other people were going to offer more proportionately. And this way … creates the right incentive."

Zubyck also said stakeholders sought a way to discourage the creation of multiple subsidiary organizations in order to clear more capacity through the tie-break.

"We acknowledge this could be a risk: The tie-break methodology does not prevent somebody from creating a subsidiary organization," she said. "However, it's one that we can't address solely through the tie-break methodology. It has larger impacts in the auction that … will be considered more broadly as part of our future enhancement discussions."

The Technical Panel is scheduled to vote to post the changes in September, with board approval anticipated in October. The Nov. 26-27 auction will seek capacity for the periods beginning May 1 and Nov. 1, 2026, with results posted Dec. 4.

No 'Misalignment' Seen

In response to questions raised at the Technical Panel's May meeting by Vladislav Urukov of Ontario Power Generation, IESO officials said they had reviewed the Technical Panel's Terms of Reference (ToR) and Chapter 3, section 4.3 of the market rules for consistency.

Urukov had asked whether provisions for amending market rules were consistent with the "deemed warrants consideration" provision in section 3.2.1 of the ToR.

"The deeming provision, although not explicit in the market rules, is supported by the IESO Board's authority pursuant to market rule s.4.3.6, whereby the IESO Board has authority to direct whether an amendment submission warrants or does not warrant consideration," IESO's Paula Lukan wrote in a *memo* to the TP. "The approval of the ToR in 2017 by the IESO Board, and in particular the inclusion of the deeming provision, constitutes the direction of the IESO Board that all IESO-driven engagements warrant consideration, thereby streamlining the process for most market rule amendments."

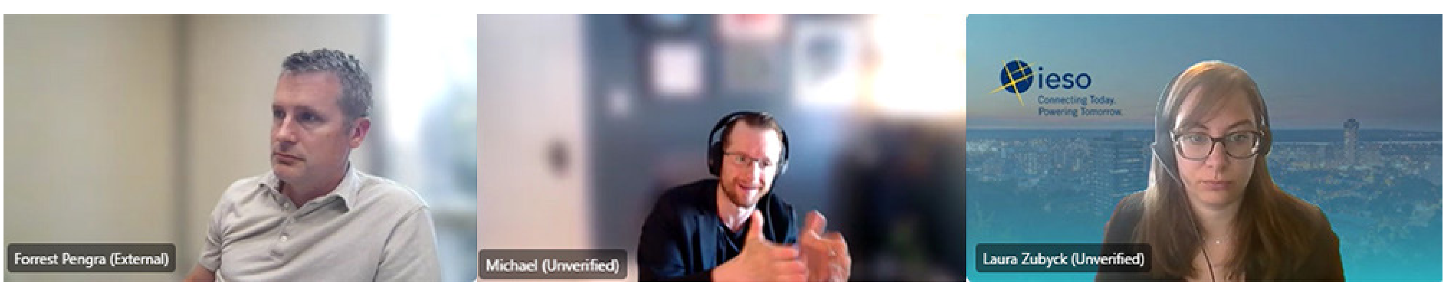
Lukan said IESO will look more broadly at section 4 of the market rules to clarify the rule amendment process as part of its initiative to review market rules and manuals not directly impacted by the Market Renewal Program.

"We conducted a review, and while we did not find any misalignment between the rules and the terms of reference, we did identify a number of instances where the market rules could benefit from greater clarity," said Lukan, who noted that the section hasn't been updated since Ontario's market opening.

"As a result, for example, it does make reference to consultations and not to stakeholder engagement."

"Are we saying that there'll be no substantive changes to the rules, just clarification that does not in any way change the rules themselves?" Urukov asked.

"I think that's right," Lukan responded. "We did recognize … in some instances it did create a little bit of confusion, but we're confident that there aren't any contradictions. It's just there is an opportunity to clarify the language. So, no substantive changes that we've identified so far. It's really just bringing them up to date, making the language a little simpler. During the [Market Renewal Program] process, this section did not get updated, so there's definitely opportunity there to make some improvement." ■



From left, Forrest Pengra, director of strategic initiatives for Seguin Township; Michael Pohlod, director of energy markets for Voltus; and IESO Capacity Auction Supervisor Laura Zubyck discuss revised capacity tie-break rules. | *IESO*

Retiring ISO-NE CEO van Welie Reflects on 25 Years at the RTO

By Jon Lamson

When Gordon van Welie first started working for ISO-NE in 2000, the organization had about 300 employees, few formalized systems and processes in place, and a resource mix dominated by nuclear, coal and oil generation.

Now, 25 years later, as he prepares to retire from the organization, ISO-NE has roughly doubled in size and oversees a rapidly evolving grid set to serve as the backbone of an electrifying and decarbonizing economy. (See *ISO-NE CEO Gordon van Welie Announces Retirement*.)

"The organization I came into was very much still in startup mode," said van Welie, who is the longest-serving head of any ISO or RTO in the country. "There was a lot of work that had to be done just to set up all the formality around an organization that's going to clear, in some years, $20 billion."

ISO-NE was created in 1997 to manage the region's grid and power markets amid restructuring, and van Welie was brought in just a few years later, initially serving as the organization's COO before his appointment as CEO in May 2001.

"I was very fortunate to be in at the early stages of the design and development of the wholesale market structure as we know it today," van Welie said.

In the few years after van Welie took over as CEO, ISO-NE developed and launched its day-ahead and real-time markets and navigated a potential three-way merger with PJM and NYISO. The merger, which was explored in response to FERC's interest in expanded ISO footprints, ultimately was abandoned due to the challenges of reconciling the differences between regions, van Welie noted.

He also oversaw ISO-NE's transition to becoming an RTO in 2005, after FERC incentivized transmission owners to join RTOs across the country. This transition, and the negotiations that surrounded it, led to NEPOOL turning over filing rights for market rules to ISO-NE and codified ISO-NE's responsibility for transmission planning in New England.

ISO-NE CEO Gordon van Welie | © *RTO Insider*

Why This Matters

ISO-NE CEO Gordon van Welie, who has led the organization for the bulk of its history, said he's confident about the organization's direction, but that a supportive federal and state regulatory environment will be key to ensuring resource adequacy in the 2030s and beyond.

"The next big adventure," van Welie said, was the creation of the region's forward capacity market, which led to a "major settlement proceeding down in Washington, D.C."

ISO-NE eventually ran its first forward capacity auction in 2008 for the 2010/11 capacity commitment period. The auction has been through 18 auction cycles, and the RTO in the midst of a major overhaul of the market intended to prepare the region for anticipated demand and supply changes associated with decarbonization efforts.

The Rise of Gas Generation

ISO-NE's resource mix has experienced a dramatic shift during van Welie's time with the RTO. As the fracking boom caused gas prices to plummet, the competitive wholesale markets helped speed the transition from oil and coal to gas generation, van Welie said.

In 2000, natural gas accounted for just 15% of generation in the region, while oil and coal accounted for a combined 40% of generation. By 2012, gas resources were responsible for 52% of generation, while oil and coal resources combined to account for about 4% of generation. Gas increased to about 55% of generation in the region by 2024. (See *New England Gas*

Generation Hit a Record High in 2024.)

Following restructuring, "there were billions upon billions of dollars invested in the region in generation assets," van Welie said. "That, I think, would not have occurred as quickly as it occurred without the establishment of wholesale markets."

The introduction of wholesale markets also has helped protect consumers from poor investments during this period, van Welie said. He highlighted Dominion Energy's decision to spend nearly a billion dollars to refurbish the Brayton Point coal plant, only for the plant to become uneconomic in just a few years because of the rise in low-cost fracked gas. The plant retired in 2017.

"That was a billion-dollar investment made by private capital that New England ratepayers never incurred," van Welie said. "It was not a good investment, and ultimately, wholesale market structure shielded consumers from those investments."

Transmission Investments

The gas generation boom was aided by the agreement in the early 2000s on a transmission cost allocation framework to regionally share the costs of reliability projects expected to bring system-wide financial benefits, van Welie said.

This helped enable major investments in transmission infrastructure, which increased transmission rates but reduced congestion costs and the need for reliability must-run contracts to retain retiring resources. These investments made it easier for new gas plants to come online, speeding up the turnover of the fleet, van Welie said.

Today, New England has the lowest congestion costs of any RTO, coupled with transmission rates that are "more than double the average rates in other RTO markets," according to Potomac Economics. (See *NEPOOL PC Briefs: June 24-26, 2025*.)

The transmission investments made during this period also have helped New England prepare for accelerating load growth and a growing influx of renewable energy, van Welie said. The RTO forecasted in its 2050 Transmission Study that the region likely will need to spend an additional $22 billion to $26 billion to meet load growth associated with heating and transportation electrification. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.)

"I think we made that investment at exactly the right time," he said, noting that the cost of new transmission infrastructure has increased rapidly in recent years.

"We laid a foundation at a time when transmission was … inexpensive relative to today," he said. "If you look at where we are today, we've got a very strong transmission system. It's well positioned to support the next stage of growth."

Resource Adequacy and Energy Transition

He said he's confident ISO-NE has adequate resources to meet load and ensure reliability through 2030 but acknowledged there are valid questions about how to ensure resource adequacy in the 2030s and beyond.

"I'm confident the ISO is going to do what it needs to do," he said, pointing to the ongoing capacity market overhaul as a "foundational ingredient to maintaining the successful trajectory we've had over the last 25 years."

However, ISO-NE cannot succeed on its own, and will need "a supportive regulatory environment for markets to be successful," van Welie added, emphasizing the need for support from both federal and state regulators and policymakers.

"If we have people pulling in opposite directions … it's going to make it that much harder for investors to have confidence in the market construct," he said.

Reiterating his testimony from the recent FERC technical conference on resource adequacy, van Welie said policymakers should work to reduce barriers to entry for new resources. He stressed that the wholesale market "rests on the premise that you can price the prevailing supply and demand conditions and produce a price signal that will attract the investment." (See *FERC Dives into Thorny Resource Adequacy Issues at Tech Conference*.)

But whatever challenges lay ahead for ISO-NE, van Welie will be off the hook come Jan. 1, 2026, when longtime COO Vamsi Chadalavada is set to take over at the organization's helm.

"I definitely will miss the ISO," van Welie said, adding that he is looking forward to spending more time with family. "I would like to stay involved in the industry in some way. So that's a new chapter in my life that I'm thinking through." ■

NEPOOL Reliability/Transmission Committee Briefs

RNS Rate Decrease

ISO-NE's regional network service (RNS) rate is set to *decrease* by about 1% in 2026, dropping from $185.28/kW-year in 2025 to $183.71/kW-year in 2026.

The slight decrease in the rate is primarily the result of a regional true-up and a year-over-year increase in load, which lowered the unit rate, Jim Augelli, representing the region's transmission owners, said at the summer meeting of the NEPOOL Reliability and Transmission Committees on July 15. He added that these factors were partially offset by ongoing transmission system investments.

The rate increased by about 20% in 2025, which the TOs attributed to increased revenue requirements. (See *NEPOOL Reliability/Transmission Committee Briefs: Aug. 13-14, 2024*.)

Over the next five years, the TOs *forecast* the RNS rate to increase to $220/kW-year by 2030, driven by growing transmission investments. However, the TOs reduced their RNS rate projections for 2027-2029 compared to the five-year forecast *presented* in 2024, lowering the forecasted 2029 rate from $217/kW-year to $210/kW-year.

Dave Burnham, also representing the TOs, stressed that the five-year forecast is solely based on "incremental revenue requirements attributable to forecasted capital investments" and "should be used for illustrative purposes only."

According to the data presented by the TOs, asset-condition projects make up 72% of the forecasted regional investments in 2025 and 2026, accounting for about $1.67 billion of $2.31 billion in anticipated capital spending.

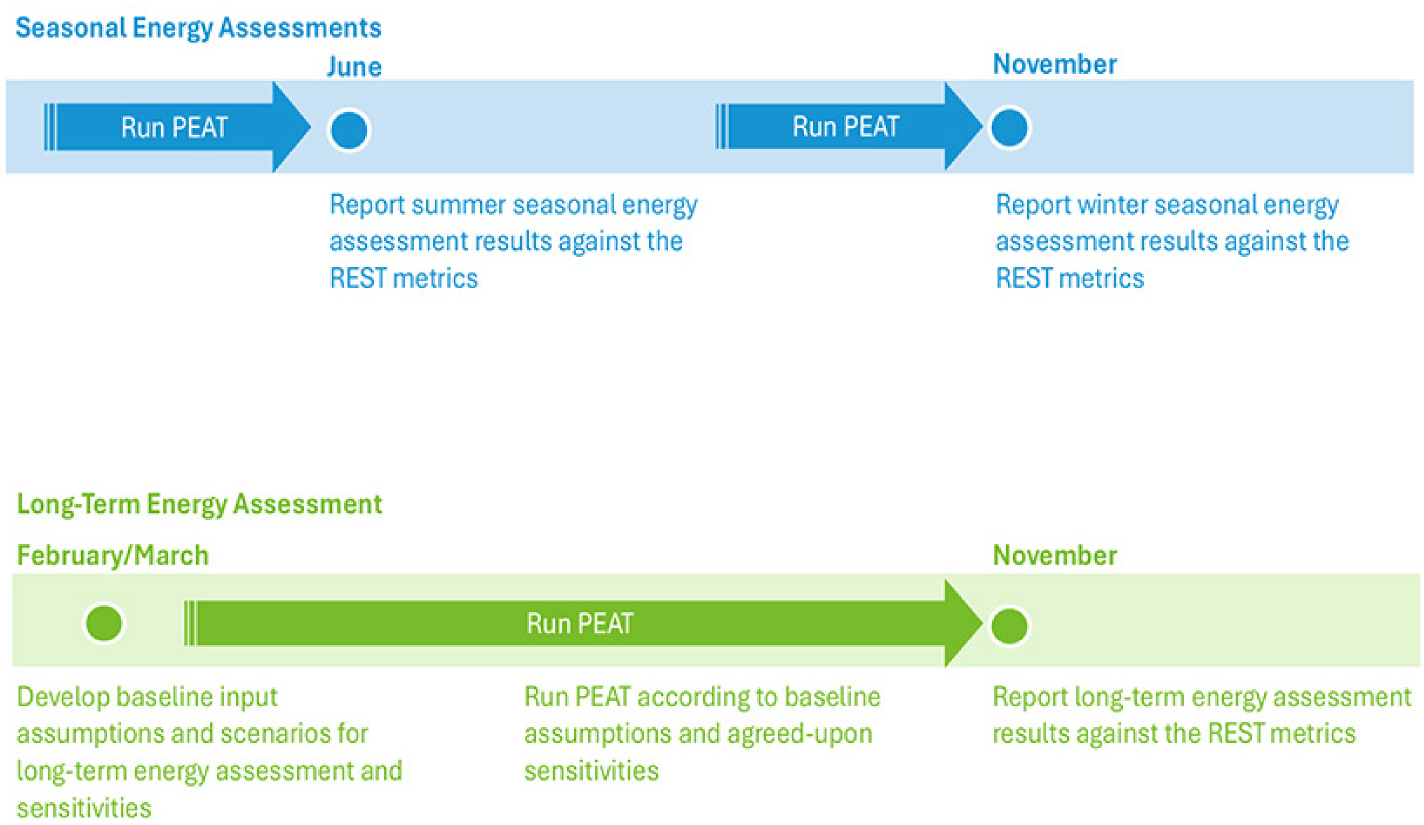
Rising asset-condition costs are a key concern of states and consumer advocates in the region, and ISO-NE is working to establish a new non-regulatory "asset condition reviewer" role at the RTO to help increase transparency and oversight on the spending. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

Costs Associated with FERC Order on Interconnection Complaint

Following up on a FERC ruling in December 2024 that TOs cannot charge interconnection customers for operations and maintenance costs associated with network upgrades, the TOs estimated that compliance with the order will increase the RNS revenue requirement by about $11.6 million and local network service revenue requirements by about $5.3 million across New England (*EL23-16*). (See *FERC Sides with New England Developers on Interconnection Complaint*.)

Regional Energy Shortfall Threshold

Also at the meeting, ISO-NE presented



ISO-NE proposed timeline for seasonal and long-term energy assessments | *ISO-NE* tariff changes associated with its proposed Regional Energy Shortfall Threshold (REST), which is intended to quantify "the region's level of risk tolerance with respect to energy shortfalls during extreme weather."

ISO-NE proposes to use the REST for short-term reliability assessments, performed ahead of upcoming summer and winter seasons, and for annual long-term assessments, looking five to 10 years into the future. The RTO plans to rely on two metrics, focused on shortfall magnitude and duration, to quantify shortfall risks against the threshold. (See *ISO-NE Details Regional Energy Shortfall Threshold Metrics* and "Regional Energy Shortfall Threshold," *ISO-NE Cuts Winter, Summer Peak Load Forecasts for 2033*.)

The RTO plans to focus the REST on the 0.25% most extreme 21-day cases it evaluates and proposes setting the threshold at 3% shortfall magnitude and 18-hour shortfall duration. The REST would be violated if the probability-weighted average shortfall duration and magnitude of the tail cases exceeds these thresholds.

It plans to publish seasonal assessments in June and November, ahead of the summer and winter seasons, and long-term assessments in November.

ISO-NE will continue stakeholder discussions at the Reliability Committee meetings in August and September.

Order 2023 Conforming Changes

Alex Rost, director of interconnection services at ISO-NE, *discussed* potential changes related to deliverability assessments for resources not subject to the RTO's interconnection procedures.

Rost noted that ISO-NE's compliance with FERC Order 2023 "removed milestones related to the assessment of deliverability" and the establishment of capacity network resource capability (CNRC) for interconnecting resources under the RTO's jurisdiction, adding that "these milestones now reside fully within the ISO interconnection process" (*ER24-2009, ER24-2007*).

Rost said ISO-NE will need to clarify its deliverability monitoring process for interconnecting resources not subject to the RTO's interconnection processes in advance of the 2026 interim reconfiguration auction qualification process.

"The ISO is proposing to formalize the concept of 'equivalent CNRC' for all resources not subject to the ISO interconnection procedures … to avoid confusion when tracking assignment of deliverability capability," Rost said.

ISO-NE has also proposed to align deliverability analysis screenings for non-RTO-jurisdiction resources with the deliverability screenings performed in interconnection cluster studies and would perform these screenings "right after the conclusion of a cluster study."

Rost said the RTO is considering tariff changes to set milestones for resources seeking to establish "equivalent CNRC," to ensure these resources "will likely achieve commercial operation." He asked for feedback from stakeholders by the end of July on potential "demonstrable commitment milestones" for these resources. ■

— Jon Lamson

CGA Says New MISO Info Guide on Queue Fast Lane Shows Plan is Unfair

By Amanda Durish Cook

AES Indiana's 200-MW Pike County BESS. The battery system was not part of the expedited queue lane. | *Fluence*

The Clean Grid Alliance claims that new information MISO has released on its interconnection queue fast lane definitively shows the plan would be detrimental to independent power producers and should be rejected by FERC.

The clean energy advocacy group wrote to FERC July 15 that a newly released informational guide from MISO that describes how the express lane would be rolled out if approved proves the plan is unfair (*ER25-2454*). Clean Grid Alliance said the *guide*, published July 11, contains a detail that would leave load-serving entities and their affiliates free to scoop up nearly 74% of the project threshold that could be allotted under the express lane.

MISO in early June refiled its fast-track proposal, this time with a 68-project limit that includes special reservations for retail choice states and independent power producers to advance their generation projects. MISO designated 10 of the 68 project slots for IPPs only. It said the dedicated spaces would discourage LSEs from using a tactic of refusing to enter into agreements with IPPs for the remaining 50 project slots. (See *MISO's Queue Fast Lane, Take 2, Nets Déjà vu Arguments*.)

But CGA said the guide's "generalized other agreement category" shows that LSEs would get preferential treatment and could shut IPPs' projects out of the 50-project fast lane if the two don't have a legally binding agreement according to MISO. MISO said it won't consider letters of intent, memorandums of understanding or term sheets as adequate for offtake agreements.

"There might have been some glimmer of hope that the generalized other agreement category would not afford LSEs unfettered veto power. However, that too has now been shut down," CGA said. "MISO's recent post puts the nail in the coffin to IPP participation in the 50-project category. LSEs will unequivocally be able to raise a unilateral barrier to IPP participation and say no."

CGA said MISO's definition of legally binding agreements leaves only power purchase or similar offtake agreements and "build-own-transfer" agreements as valid avenues to the lion's share of the fast lane. The alliance said LSEs "would wield unchecked market power to simply say 'no' to an agreement with an IPP, leaving LSEs with exclusive use of the 50 projects as they desire, including self-supply or contracting with an affiliate."

CGA told FERC the wording in MISO's guide attempts to add a late-stage revision to which interconnection requests can enter the fast lane. It also said the seemingly new requirement "follows MISO's pattern in this docket to continually revise its filed proposal." The alliance said that by burying the new condition in an information guide, MISO shut out public comment and FERC's ability to review the proposal in its totality.

"MISO did not apprise the commission of this legally binding substantive change to the other agreement category," CGA wrote and again urged FERC to reject the plan.

At press time, MISO hadn't responded to *RTO Insider*'s request for comment on CGA's claim. ■

National/Federal news from our other channels

Interior Dept. Places Solar, Wind Under Close Review

NetZero Insider

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

MISO Tries to Ward off DR Fraud with New Testing Regime

By Amanda Durish Cook

MISO has filed with FERC to impose more exacting testing requirements on its demand response resources in an effort to stop fraud in its capacity market.

The filing seeks to eradicate a standard option for DR owners to submit mock, hypothetical testing of their capabilities instead of demonstrating actual reductions through real power tests. Under the new paradigm, DR owners can proceed with a mock test only if a state authority expressly allows it or if it's a proven resource that has responded to a MISO call in the past three years and hasn't changed its specifications. (See *Amid Fraud, MISO Plans Stricter Testing of Demand Response*.)

MISO asked for a July 15 effective date in its July 14 *filing* (ER25-2845). It said making real power tests the norm is necessary to "address instances of fraudulent registration facilitated, in part, by use of the testing waiver currently in the tariff to register resources from which no demand reduction is possible." MISO plans the testing requirements to be in full force by the 2027/28 planning year.

The grid operator said it needs confidence that the demand reduction capability that clears in its seasonal capacity auctions corresponds to resource performance in real time. MISO said the stepped-up testing standards should result in improved grid reliability, with "MISO operators having greater confidence in the ability of registered resources to perform when called upon during emergencies."

If the rules go through, demand response resource owners must demonstrate they can honor their notification time while dropping demand within the same time-of-day periods that correspond to hours that MISO expects system risk to occur and has picked out ahead of time. The resources must hold their demand reduction for 15 minutes, covering at least two-meter intervals.

MISO proposed that demand response owners must show a full reduction of all the megawatts they specified in registration during a real power test. MISO said it would allow some resources that experience a weather impact during testing to show a little less than their full stated capability.

"The test is not a panacea. It is a bare minimum requirement to show us you can drop," MISO's Joshua Schabla said at a July 9 Resource Adequacy Subcommittee meeting. "We don't want the test to barrier to entry. We just want the test to validate that you can do what you say you can do."

MISO Independent Market Monitor Carrie Milton said MISO's new testing requirements are likely to weed out demand response forgeries.

The MISO IMM has been circulating this graphic (and one-liner) showing an empty field where a data center that cleared the MISO 2024 capacity auction should be located. | *Potomac Economics*

What's Next

MISO will wait to hear from FERC on whether it can require its demand response fleet to make actual megawatt reductions when fulfilling testing requirements.

Milton also said she and monitoring staff continue to review past conduct of demand response and load-modifying resources in MISO. She said there's likely more instances of manipulation and emphasized IMM David Patton's past contention that a yet-unconstructed data center was able to clear capacity in MISO's 2024 capacity auction.

"If you're just an empty field, you really can't conduct a test," Milton said at the July 10 MISO Market Subcommittee meeting.

Since 2024, MISO has planned five total FERC filings in response to recent instances of demand response gaming the RTO's capacity market or coming up short when called upon.

The RTO already has made three filings: one to introduce a new availability-based capacity accreditation for demand response; another to stop emergency demand response from also registering as an load-modifying resource (LMR) or demand response resource; and another to crack down on bad actors by forbidding demand response owners from double-counting participants, making fraudulent registrations or deliberately inflating their baseline electricity use to exaggerate reductions.

In addition to the testing clampdown, MISO said a fifth and final filing will put new non-performance penalties in place and allow market participants to replace their LMR capacity after clearing the MISO capacity auction if the resource is rendered unable to respond during a planning year. ■

FERC Sides with Market Monitor over MISO in Compensation Dispute

RTO Challenged Reimbursing Potomac Economics for Reviewing Tx Planning Process

By James Downing

FERC on July 18 rejected a petition from MISO seeking approval to not pay its Independent Market Monitor, Potomac Economics, for monitoring its transmission planning process (*EL25-80*).

MISO's petition argued that the IMM's review of its recent long-range transmission plans exceeds the scope of the Monitor's authority and has contributed to recent cost overruns compared with the IMM's contract.

IMM David Patton has argued that MISO's tariff unambiguously authorizes him to monitor transmission plans, which have clear impacts on the wholesale markets. (See *MISO IMM Contends He Should Have Role in Tx Oversight*.)

RTO tariffs give rise to and define the scope of an IMM's authority, and FERC and the courts have consistently found Monitors are limited to the authority laid out for them there and in agreements they sign with grid operators. In interpreting the MISO tariff, FERC had to address whether it unambiguously addresses the issue at hand — and the commission found that it does.

As the order pointed out, section 53.1 of the MISO tariff says the IMM can review any RTO actions that affect any of its markets and services.

"We also find that MISO's transmission planning is an action that affects its markets and services, and that section 53.1.e unambiguously authorizes the IMM to review and analyze the competitive or other market impacts of MISO's transmission planning," FERC said.

FERC said it found no conflict in letting the IMM monitor transmission plans while MISO retains the sole authority to conduct transmission planning. The tariff does not let the IMM engage in transmission planning but simply authorizes him to review its impact on the market.

"We see no conflict between our finding here and the fact that the costs of transmission planning and of market monitoring are recovered under separate schedules to the tariff," FERC said. "The cost recovery of transmission planning under Schedule 10 of the tariff is not relevant to the instant proceeding."

MISO IMM David Patton | © *RTO Insider*

Why This Matters

In siding with the Market Monitor in a dispute with MISO, FERC made clear the impact of transmission planning on markets falls under the Monitor's purview.

FERC rejected also MISO's argument that siding with Patton would be the same as amending the tariff absent a filing under Section 205 of the Federal Power Act.

And while MISO transmission owners had argued the case could risk the IMM involvement in any business area within the ISO, FERC found the tariff requires that the Monitor only watch issues that "affect the competitiveness, economic efficiency and proper operations of the markets and services."

FERC said also that because no party had asked it to review any specific activities undertaken by the IMM, it was in no position to determine whether specific activities in the proceeding should have been billed to MISO. The commission encouraged the parties to work collaboratively on resolving such disputes.

'Recognized and Applauded'

The order drew a pair of concurrences — one from Chair Mark Christie and another from Commissioner David Rosner.

"That transmission planning affects RTO markets is factually undeniable and thus makes this order an easy legal call," Christie said.

Growing calls for expanding transmission are coming as consumers are facing rising bills, driven in large part by the rising costs of that infrastructure.

"Despite the understandable concern and publicity over capacity market auction results in MISO and PJM over the past year, transmission costs are the single biggest driver of skyrocketing monthly power bills and have been for years," Christie said. "Transmission costs are driven not by the price of fuels such as natural gas, coal or oil, which change literally hourly and are set in global markets, but by capital expenses (capex), which are a result of intentional planning and intentional policy decisions, in this case by the management of MISO."

The latest long-range plan comes with a price tag of $21.8 billion along with additional costs such as financing and return on equity that will be passed onto consumers.

"So, to his credit, MISO's IMM has stepped up and provided a critique of the assumptions and calculations used by MISO to develop and attempt to justify this latest costly tranche of transmission projects," Christie said. "Since the transmission planning that produced this tranche obviously affects the rates consumers pay, this is exactly what the MISO IMM and any market monitor should do."

Christie noted also that state regulators and consumer advocates defended the IMM in the proceeding, which he said was in line with his experience with PJM during his time as a Virginia regulator.

"The role of an IMM requires courage and a willingness to put his job on the line by bringing to light uncomfortable (for some) facts and drawing conclusions about those facts that he is prepared to defend forthrightly," Christie wrote. "The MISO IMM has done so here and he should be recognized and applauded."

Rosner wrote separately that it is important that a Monitor and its RTO should have a good working relationship, and ideally MISO and Patton should have settled the dispute on their own.

"In a situation like this one, which is essentially a contractual dispute, the best outcomes are achieved when the parties reach agreement among themselves — not when the commission is asked to interpret decades-old language," Rosner said. "When parties ask the commission to answer a 'yes or no' question, they forfeit the opportunity to reach a compromise solution that results in better outcomes for everyone involved."

He noted also that nothing in the order should be read as a requiring an independent transmission monitor, a concept discussed in Order 1920 that the commission could not reach consensus on. ■

NY Steps Back from OSW, Halts Offshore Tx Planning Process

Underwater Wire Network's Cost Could Have Exceeded $20B

By John Cropley

New York is pausing its ambitions and halting the planning of an underwater transmission network as President Donald Trump strangles the offshore wind sector.

It is the latest of several states and developers to step back from such efforts since autumn 2024.

New York's most recent solicitation for wind turbines remains in play, but it is behind schedule, and the finances of the proposals submitted in 2024 might be altered by the recent loss of tax credits.

And of course, any of the proposals that rely on the planned underwater grid will need a different strategy.

The New York Public Service Commission on July 17 *shut down the process* to build an underwater transmission network to bring electricity to shore from the hundreds of wind turbines the state hopes to see spinning off its coastline.

With the Trump administration actively thwarting offshore wind development, the goal of 9 GW of offshore wind capacity by 2035 is out of reach, the PSC said.

It became necessary to stop the planning of a transmission network to serve wind turbines that will not soon be built, lest New York ratepayers be liable for unknown and potentially large expenses.

Unlike wind turbine developers, who begin to collect their ratepayer-funded subsidies only when their project enters commercial operation, the transmission developer would be eligible for cost recovery immediately — even if the wind turbines the wires were to connect to were delayed or never built, or even if the wires themselves never were built, only planned.

Why This Matters

One of the strongest supporters of offshore wind development has acknowledged that progress is impossible under President Trump.

Foundation components for the Sunrise Wind project planned for construction off the New York coast are shown in Coeymans in 2024. | *NYSERDA*

PSC Chair Rory Christian lamented the pause being placed on the state's offshore wind program, which has been in the works for more than a decade. He blamed the Trump administration's "deliberate and systematic action" to block offshore wind in New York and in other states.

"We at the commission cannot in good conscience ask New York ratepayers to shoulder the cost and risk of a project where we know we'll be stymied going forward," he said.

The early projects — South Fork Wind, Empire Wind 1 and Sunrise Wind — rely on radial lines, each sending their own export cable ashore in different locations. There is limited space for routing and landing such cables in the crowded downstate region, however, so the strategizing turned to a meshed design where multiple wind projects would use a single export line built through a separate transmission project.

The now-withdrawn Public Policy Transmission Need (PPTN) was formally identified by the Department of Public Service in June 2023 (*Case 22-E-0633*). It called for NYISO to solicit and evaluate proposals for a transmission project that could deliver 4.8 to 8 GW from multiple wind farms to NYISO Zone J (New York City).

At the time, it seemed like New York had a good chance of achieving its 9 GW goal. But since then, little in the offshore wind sector has proceeded as state planners had hoped.

Developers canceled contracts that no longer were viable and rebid them at much higher prices. An entire solicitation had to be canceled due to the specified turbine not being available. Proposals were withdrawn ahead of the 2024 presidential election and paused afterward. Trump's Day One directive froze some development in U.S. waters outright and cast paralyzing uncertainty over other efforts. A federal stop-work order was slapped on Empire Wind 1 for a time.

Most recently, the budget reconciliation bill throws future projects' finances into turmoil by eliminating tax credits and introducing new challenges with foreign components.

Against this backdrop, NYISO issued the PPTN solicitation in April 2024. NYISO reported in October 2024 that all 28 proposals received from four developers were eligible for evaluation.

On June 25, NYISO presented an analysis to stakeholders showing that preliminary independent estimates of the cost of those projects ranged from $7.9 billion to $23.9 billion.

NYISO was on track to potentially select a project later in 2025 under terms of the PPTN, which would result in costs beginning to accrue for ratepayers.

DPS staff looked for ways to pause, modify or break the PPTN down into phases but found none. They recommended the PSC withdraw the PPTN.

The commissioners voted 6-0 for this move July 17, and each expressed worry, frustration or even anger beforehand.

"We live at a moment when a philosophical battle is going on between those vying to wield the levers of governmental power at all levels. The battle is not between right and left, but between empiricism and magical thinking," Commissioner John Maggiore said, adding:

"But we should not respond with our own form of magical thinking — sustaining a zombie process that could result in transmission lines to nowhere will not help us achieve our 9-GW legal mandate. It will just end up costing already-stressed ratepayers more money for which they will get nothing in return."

Christian said the state remains convinced of the importance and value of offshore wind but must defer it to a future where federal policy is more supportive.

Offshore wind has been a centerpiece of New York's decarbonization strategy, but it is only one piece, he said: "In the meantime, we have to focus our attention on building the clean energy infrastructure we can, to advance to completion while remaining focused on progress toward meeting the state's goals."

The New York State Energy Research and Development Authority, a lead agency in the energy transition and manager of the offshore wind solicitations, said later July 17 that it will use this pause to refine its efforts to support the industry in New York State and engage with stakeholders and the supply chain.

It also said it's continuing to process its *fifth wind solicitation*, which attracted four developers in 2024 and is lagging behind the expected timeline for completion.

Many stakeholders and interested parties who submitted comments to the DPS about the PPTN earlier in 2025 had urged that the PSC not give up on it.

Some expressed regret that it did.

"Now is not the time for us to hold back the potential contribution of any energy source," Turn Forward Executive Director Hillary Bright said.

The New York League of Conservation Voters said it was deeply disappointed. "While the federal government continues to undermine progress on clean energy, New York should be doubling down on our commitment to become energy independent, not stalling it."

The Alliance for Clean Energy New York and its New York Offshore Wind Alliance said: "Offshore wind projects can take more than a decade to develop, spanning far beyond state and federal election cycles. We encourage New York State to continue developing infrastructure in the near-term that will enable new generation to come online, addressing reliability and affordability for New Yorkers."

Christian acknowledged these sentiments before the vote but said ignoring the Trump administration's hostility to offshore wind would be "incredibly risky" for ratepayers: "Offshore wind is unique in that the federal government has a direct permitting and financial role, and the federal government has repeatedly and deliberately withdrawn its support." ■

FERC Accepts NYISO's Firm Fuel Tariff Revisions

By Vincent Gabrielle

FERC on July 14 approved NYISO's tariff revisions that change the mechanism by which generators opt in to the "firm fuel" capacity accreditation resource class, enable modeling improvements related to natural gas constraints and update the bidding requirements for capacity suppliers (*ER25-2245, ER25-2257*).

The proposal was the subject of months of discussions between NYISO, stakeholders and the Market Monitoring Unit. (See *Firm Fuel Proposal Continues to Confuse NYISO Stakeholders*.) The Board of Directors approved the revisions in May.

The revisions, effective July 16, are aimed at shoring up winter fuel as the New York grid transitions into a winter-peaking system. Both the ISO and the New York State Reliability Council are concerned that the downstate gas turbine fleet will find itself competing with home heating for fuel during peak periods.

Suppliers will have until Aug. 1 each capability year to opt into the firm fuel capacity accreditation resource class. For the first capability year under the new paradigm, 2026/27, NYISO requested — and FERC approved — a slightly later deadline of Nov. 1 for generators to elect as firm to give market participants time to adjust to the changes.

Generators opting firm must have fuel supply, transportation and replenishment strategies in place by Dec. 1 of the capability year through the end of February. They must be able to run for 56 hours over seven consecutive days during the winter period.

If a generator is unable to secure firm fuel supplies or if something has gone wrong with the fuel supplier, it is required to notify NYISO. Doing so essentially compensates that generator as if it opted as non-firm. Failure to notify NYISO could result in audit and financial sanctions.

Failure to perform as required could result in audit and financial sanction if the failure was found to be within the plant management's control.

NYISO's tariff revisions were supported by the Independent Power Producers of New York and Ravenswood Operations. They told FERC that proposal will produce "efficient outcomes that reflect the marginal reliability value of conventional generators" and better address winter reliability risks. ■

Bayonne Energy Center in Bayonne, N.J. | *Jim Henderson, CC BY-SA-4.0, via Wikimedia Commons*

NYISO MC Liaison Brief

ALBANY, N.Y. — The NYISO Board of Directors has approved the right of first refusal for transmission owners' tariff revisions for economic and reliability projects. The board also approved the PJM joint operating agreement for the Dover phased array regulator substation.

NYISO headquarters in Rensselaer, N.Y. | *NYISO*

(See *NYISO Management Committee Briefs: June 30, 2025*.)

In a presentation to stakeholders, Board Chair Joseph Oates ran through a laundry list of items the board covered over two days of management meetings. He reported that the board is pleased with the discussion of the ongoing capacity structure review with market participants. The board also reviewed the preliminary setup of the System and Resource Outlook study, which eventually will involve meetings with stakeholders.

Oates said the board also reviewed the status of the project prioritization process and had received the results of the 2025 quarterly internal audit. Physical and cybersecurity program updates were reviewed. He also mentioned a "strategic discussion" about short- and long-term demand forecasting.

Why This Matters

The board has accepted several tariff revisions for FERC filings. The discussion of load forecasting signals concern with what demands will be placed on a stressed grid.

Oates did not provide details of these reviews or status updates. Stakeholders did not ask questions. ■

— Vincent Gabrielle

NYISO: LBMPs Spiked in June from Heat Wave

ALBANY, N.Y. — The heat wave at the end of June caused the average location-al-based marginal price for the month to increase dramatically, NYISO *told* the Business Issues Committee on July 16.

The LBMP jumped from $36.99/MWh in May to $58.96/MWh, nearly 49% higher than that of June 2024's $39.68.

| *Shutterstock*

"June 2025's average year-to-date monthly cost of $77.60/MWh is a 90% increase from $40.78/MWh in June of 2024," said Zachary T. Smith, newly promoted to NYISO director of market solutions. Smith's promotion was announced as he began the presentation.

Natural gas prices were slightly lower in June, at $2.27/MMBtu compared to $2.34 in May, but they were up about 30% year-over-year.

Smith said the higher LBMPs were driven by the extreme heat at the end of June. (See *NYISO Issues Energy Warning as Heat Wave Boils New York*.) The heat caused shortage pricing because of a lack of energy reserves. NYISO had to make emergency purchases from neighboring regions. (See *NYISO Details Late June Heat Wave for Reliability Council*.)

Given the current and recent weather, NYISO likely would see high prices in July, too, Smith said.

"We're not done with heat waves," he said. "We might see [load] of over 30,000 MW today." During the June heat wave, demand reached over 31,000 MW. ■

— Vincent Gabrielle

Virginia SCC Orders Changes to Dominion Energy's IRP Process

By James Downing

The Virginia State Corporation Commission determined in an *order* issued July 15 that Dominion Energy's 2024 Integrated Resource Plan was legally sufficient, but it ordered changes to the utility's future IRPs.

"The commission emphasizes, though, that such acceptance does not express approval in this final order of the magnitude or specifics of Dominion's future spending plans, the costs of which will significantly impact millions of residential and business customers in the monthly bills they must pay for power," the SCC said.

State law requires at least 15 years of planning in an IRP, but it gives the regulator flexibility to require more time. Dominion must file plans that look 20 years out, in line with PJM's 20-year forecast window. That also will help the IRP be better coordinated with the utility's planning to meet Virginia's renewable portfolio standard.

The utility also will have to submit at least one scenario where its generation plans are in line with the default carbon targets in the Virginia Clean Economy Act.

In the next IRP, Dominion will have to model increasing its annual build limits for storage and investigate long-duration storage as those technologies become commercially viable. Dominion also must model higher levels of efficiency for 2026 through 2028, which will influence its use of demand-side management.

Why This Matters

Dominion Energy's territory is facing major load growth, and the SCC wants it to use more tools like grid-enhancing technologies, efficiency, demand management and storage in its planning to address its needs.

Dominion Energy headquarters in Richmond, Va. | *Dominion Energy*

Its next filing also must include a narrative discussion of its potential use of grid-enhancing technologies and advanced conductors, especially using them to ensure reliability and safeguarding the physical and cybersecurity of the distribution system.

Dominion will be required to keep using PJM's demand forecast, minus efficiency targets and separating out the load associated with data centers, the order said.

A statement from the utility welcomed the SCC's thorough review and said it would follow the new requirements for its future IRPs.

"Our customers are using 5% more power each year, and demand is expected to double in 10 years. This is the largest growth in power demand since the years following WWII," a Dominion spokesperson said in the statement. "We're focused on serving our customers' growing needs with reliable, affordable and increasingly clean energy. We're investing in new power generation from every source, grid upgrades to strengthen reliability and energy efficiency programs to help our customers save."

Most of the new power generation being developed is from carbon-free resources, including the Coastal Virginia Offshore Wind project. It's the largest offshore wind project being built in the country, and Dominion has the third-largest solar fleet. The growing demand also will require natural gas, because renewables are not always available, the company said.

Clean Virginia, which was an intervenor in the IRP case, welcomed the changes from the SCC but called for further reforms so that monopoly utilities no longer control the planning process.

"This latest order underscores how broken Virginia's energy planning process is," said Clean Virginia Deputy Director Dyanna Jaye. "Year after year, Dominion files plans that ignore clean energy requirements, lock in expensive fossil fuel infrastructure and drive up electric bills. By recognizing the harm this process can cause to Virginia families and businesses, the commission has taken a step in the right direction by calling for significant reforms moving forward."

Dominion said it was focused on keeping rates affordable and delivering value for its customers.

"Our residential rates remain below the national average, and they're projected to grow by less than 3% a year," its spokesperson said. "At the same time, we're delivering more reliable service by burying power lines in the most outage-prone areas. That's substantially reducing storm-related outages and shortening restoration times for our customers." ■

FERC Opens Door for PJM to Refile RTEP Protocol Proposal

By Devin Leith-Yessian

FERC on July 14 opened the door for PJM to resubmit a previously rejected proposal to shift its Regional Transmission Expansion Plan (RTEP) protocol from its operating agreement (OA) to its tariff, while dismissing a rehearing request for a connected proposal by the RTO's transmission owners (*ER24-2336*).

PJM's RTEP protocol proposal had been linked with another proposal by several transmission owners (TOs) to revise the RTO's Consolidated Transmission Owners Agreement (CTOA), including adding "overlap provisions" that would have required PJM to consult with TOs before proceeding with a regional project that would address the same need as a local, supplemental project proposed by a TO.

The TO proposal also would have established a conflict mediation process for instances when a TO contended that an action by the PJM Members Committee conflicts with the CTOA.

PJM and the transmission owners had asked the commission to consider both filings as one proposal, arguing that one could not be approved without the other.

But in a December 2024 order rejecting the proposals, the commission found the CTOA changes would impinge on PJM's independence by providing TOs with an exclusive opportunity to affect filings PJM is able to submit under Section 205 of the Federal Power Act (FPA). (See *FERC Rejects PJM and Transmission Owners' CTOA Proposals*.)

At the same time, FERC also rejected PJM's proposal to shift the RTEP protocol to the tariff because of its tie with the CTOA revisions, while finding also that PJM had not made the case that keeping the planning protocols in the OA renders the RTO's governing documents unjust and unreasonable.

The July 14 rehearing order again rejected the CTOA revisions, saying they would grant TOs too much influence over PJM's decision making on planning, extend *Mobile-Sierra* protections to the revised language and place "substantive transmission planning rules in the CTOA."

"The CTOA amendments go beyond changes to enable this transfer and also would restrict PJM's ability to make independent FPA Section 205 filings that PJM TOs believe contravene the CTOA, add substantive transmission planning rules to the CTOA, and grant the *Mobile-Sierra* public interest standard presumption to several CTOA provisions," the commission wrote. "Thus, the broad cumulative effect of the integrated package of filings would be to shift the ability to influence PJM's FPA Section 205 filings from a diffuse right shared by the Members Committee representing diverse interests to a concentrated right possessed by a single class of stakeholders, the PJM TOs. Moreover, PJM TOs' new rights would be housed in the CTOA and granted *Mobile-Sierra* protections, which would raise the bar for any future changes."

However, the commission withdrew its determination that PJM's proposal had not met the FPA Section 206 burden of showing that the OA is unjust and unreasonable with the inclusion of the RTEP protocol, instead dismissing the proposal as moot given the rejection of the intertwined CTOA revisions.

"We emphasize that our dismissal of the PJM complaint here does not preclude a future filing proposing to move the RTEP

Why This Matters

FERC's order could allow PJM to refile a proposal to transfer its RTEP protocol from its Operating Agreement to its tariff without making revisions to its Consolidated Transmission Owners Agreement.

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Continued on page 43

$92B in Power, Data Center Infrastructure Planned in Pa.

Industry Leaders, Trump Announce Plans at Energy Summit

By John Cropley

New technology and energy facilities are planned for Pennsylvania at a cost of more than $90 billion, including multiple power plants and data centers, possibly co-located.

President Donald Trump, cabinet secretaries, the state's junior U.S. senator and leaders of industry-leading firms in both sectors announced the projects July 15 at the Pennsylvania Energy & Innovation Summit in Pittsburgh.

The vision they laid out breaks down to $56 billion in new energy infrastructure and $36 billion in new data centers. Trump and most of the other speakers framed the announcement as progress toward — and evidence of — the energy dominance the nation must have as it pursues its new Golden Age.

"Get ready, lots of jobs, lots of success, really, a beautiful thing, it's going to be beautiful to behold," Trump said.

He called EPA Administrator Lee Zeldin "the most important man on the dais" for his role in easing the regulations and limits that could slow progress toward that goal.

U.S. Sen. Dave McCormick (R), *hosting the event* at Carnegie Mellon University, said he believed people will look back at the day as a seminal moment in the history of the state and perhaps even the nation.

Trump, McCormick and many others continued the narrative that vast amounts of power are key to dominating the artificial intelligence sector, which in turn is key to the United States' future leadership role in the world.

Why This Matters

The plans are a potentially major package of new power demand and new generation to meet that demand.

President Donald Trump speaks at the Pennsylvania Energy & Innovation Summit in Pittsburgh on July 15. | *Sen. Dave McCormick*

Neither Trump nor any of the speakers who followed him indicated where the new generation equipment would be sourced for all these projects. It is widely reported to be in short supply with a long waiting list for new machinery.

Projects announced or mentioned at the event include:

- *Blackstone plans to invest* more than $25 billion in Pennsylvania's digital and energy infrastructure; subsidiary QTS already has acquired multiple data center sites in the northeast area of the state and will seek partners for the buildout. An additional $60 billion of in-state investment is expected to result.
- PPL has *formed a joint venture* with Blackstone to invest in new gas-fired power plants.
- Transmission operator *FirstEnergy plans to spend* $15 billion on infrastructure, personnel and processes to upgrade the grid in Pennsylvania through 2029.
- Google, which plans $25 billion in data center construction and AI infrastructure across the PJM footprint in the next two years, announced a *framework agreement* with Brookfield Asset Management to deliver up to 3 GW of hydropower across the United States — the first deal of its kind — starting with two Pennsylvania facilities rated at 670 MW.
- Google also plans to expand a previous grant to train new electricians in Pennsylvania and says it will offer free AI training to every small business in the state.
- AI hyperscaler *CoreWeave says it will commit* more than $6 billion to equip a new data center in Lancaster and will be the tenant of the site.
- Constellation Energy, which is investing $1.6 billion to restart the former Three Mile Island Unit 1 near Harrisburg, plans to perform 340 MW of uprates on its Limerick Clean Energy Center, Trump said, though *Constellation itself said* that work depends on securing customer commitments for the increased output.

- Westinghouse Electric, headquartered in suburban Pittsburgh, plans to collaborate with Google Cloud to use AI tools to enhance and streamline construction and operation of nuclear plants. Westinghouse in June announced it is working to start construction of 10 new reactors — a $75 billion proposition — nationwide by 2030.
- As announced in April, data centers and the nation's largest gas-fired power plant are planned for construction where Pennsylvania's largest coal-fired plant once stood, in Homer City, at a cost of $15 billion.

As he cheered the Homer City project, Trump lamented that he could not follow through on his campaign trail promise to save the coal plant there.

But he reminded the summit audience that the rule within his administration is that coal can be referenced only as "beautiful coal."

The gesture seems not to have infused the U.S. energy sector with the same level of enthusiasm so far — no one has announced construction of a new coal plant, only delays on retirements of existing facilities.

However, the president's cheerleading for coal resonates with many in Pennsylvania, once the nation's leading coal producer and still the third-highest coal-producing state.

The Keystone State is a fossil powerhouse, in fact: It was the birthplace of the modern petroleum industry and, thanks to hydrofracking technology and a massive shale formation, it is now the No. 2 natural gas producer in the nation.

It's also the second-highest state for electricity generation and is home to the second-most productive nuclear fleet.

Any of those technologies would be fine to power a data center boom in Pennsylvania, Trump allowed, then added a dig at one of his favorite targets: wind turbines.

"They'll be powered by maybe nuclear, maybe gas, maybe coal … they won't be powered by wind because it doesn't work."

No worries: Pennsylvania is far down in the ranks of wind-powered states, cranking out only 2.7% as much as nation-leading Texas in 2023.

To round out the picture, Pennsylvania has the fourth-highest amount of carbon dioxide emissions, behind the much more populous Texas, California and Florida. ■

FERC Opens Door for PJM to Refile RTEP Protocol Proposal

Continued from page 41

protocol from the OA to the tariff. The PJM board has the authority to petition the commission under FPA Section 206 to modify any provision or schedule of the OA that the PJM board believes to be unjust, unreasonable or unduly discriminatory," the commission wrote.

'Resounding Victory'

Ari Peskoe, director of Harvard's Electricity Law Initiative, said the rehearing order protects PJM's independence and creates an uphill battle for TOs appealing the commission's determination.

"The rehearing order cements a resounding victory for the region's consumers," Peskoe told *RTO Insider* in an email. "The utilities' proposed CTOA would have compromised PJM's independence by letting the utilities interfere with PJM's decision-making processes, particularly about transmission planning. That's why state regulators, consumer advocates, generators and public power lined up against the CTOA. Because FERC reiterated three separate and independent reasons for finding the utilities' CTOA deficient, the utilities will have a nearly impossible task in trying to convince the D.C. Circuit to reverse FERC's order."

Peskoe argued also that the CTOA revisions were not legally necessary for PJM to transfer the RTEP protocol to the tariff and the RTO can now pursue the changes on their own merits.

"With FERC's modification, PJM is now free to try again — on its own — to move the regional transmission planning provisions from the operating agreement to the tariff. However, rather than filing a complaint, PJM should try to work with its members to see if there's a deal on governance that might be acceptable to a majority of its members and to state regulators," he said.

PJM did not respond to a request for comment on whether it plans to refile the proposal or thinks that would require a fresh consultation with its membership.

Alex Stern, Exelon director of RTO relations and strategy, said the utility expects PJM and member TOs to continue working to find solutions to ensure the grid keeps up with accelerating load growth. Defending PJM's proposal to transfer the RTEP protocol during a May 2024 Members Committee meeting, he said TOs would be giving up stakeholder process veto rights over planning as part of the proposal in an effort to ensure PJM has the authority it needs to plan projects that can facilitate the clean energy transition while meeting reliability challenges. (See *Members Vote Against Granting PJM Filing Rights over Planning*.)

"We are still reviewing the order, and there is still an appeal pending," Stern said. "The CTOA is the foundation of the relationship between the transmission owners and PJM. Both are bound by this agreement and mutual responsibilities to work with one another. Nothing in FERC's order changes that. We expect the TOs and PJM will continue to discuss ways to ensure PJM has the necessary tools to plan transmission to support load growth, including AI needs, and the evolving grid." ■

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability and Members committee meetings on July 23. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

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

Markets and Reliability Committee

Consent Agenda (8:35-8:40)

The committee will be asked to endorse a consent agenda that includes:

C. proposed *revisions* to Manual 10: Pre-Scheduling Operations, Manual 11: Energy & Ancillary Services Market Operations, Manual 14D: Generator Operational Requirements, Manual 21B: PJM Rules and Procedures for Determination of Generating Capability, Manual 27: Open Access Transmission Tariff Accounting and Manual 28: Operating Agreement Accounting to conform with the third phase of PJM's market rules for hybrid resources. This phase aims to make clarifications to the rules developed in the earlier stages and further develop rules for non-inverter-based hybrids, such as gas and storage.

Issue Tracking: *Hybrid Resources Enhancements (Hybrids Phase 3)*

D. proposed *revisions* to Manual 14C: Generation & Transmission Interconnection Facility Construction, drafted through the document's periodic review. The changes would add detail to the milestone requirements for generation interconnection agreements and interconnection service agreements.

E. proposed *revisions* to Manual 18: PJM Capacity Market to conform with several rule changes approved by FERC (*ER25-682*, *ER25-785*, *ER24-2995* and *ER25-1357*). The package includes codifying how PJM will model the output of some resources operating on reliability-must-run agreements as capacity; maintaining a combustion turbine as the reference resource; establishing a uniform Capacity Performance penalty rate; removing a categorical exemption allowing intermittent, storage and hybrid resources to avoid submitting capacity offers; eliminating the energy efficiency addback; and instituting a capacity price floor and lowering the maximum price for the next two capacity auctions. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

Endorsements (8:40-11:25)

2. Operating Reserves Clarification (8:40-9:05)

PJM's Lisa Morelli will review a joint *proposal* from the RTO and Independent Market Monitor to rework how uplift credits and deviation charges are calculated in an effort to encourage resources to follow dispatch instructions. It includes the creation of a new tracking ramp-limited megawatt desired (TRLD) metric designed to follow how resources respond to instructions over time, rather than being limited to five-minute intervals. (See "Stakeholders Narrowly Endorse Uplift Changes," *PJM MIC Briefs: April 2, 2025*.)

The committee will be asked to endorse the proposal and corresponding tariff and Operating Agreement revisions.

Issue Tracking: *Operating Reserve Clarification for Resources Operating as Requested by PJM*

3. Manual 14H: New Service Requests Cycle Process Revisions (9:05-9:30)

PJM's Michelle Farhat will review *revisions* to Manual 14H: New Service Requests Cycle Process to conform with a FERC-approved settlement between the RTO and several developers seeking changes to the site-control requirements for new resources (*ER25-1544, EL25-22*). The RTO is also seeking to rework the site control needed for each project milestone to clarify when parcels can be added or removed. (See *PJM Presents Settlement on Site Control Requirements*.)

The committee will be asked to endorse the proposed manual revisions upon first read.

4. 2027/2028 Base Residual Auction, Installed Reserve Margin and Forecast Pool Requirement (9:30-9:55)

PJM's Josh Bruno will *present* the RTO's recommended forecast pool requirement and installed reserve margin. Both values would increase for the 2027/28 Base Residual Auction over the previous auction.

The committee will be asked to endorse the values upon first read. Same-day endorsement will be sought at the MC.

5. Sub-annual Capacity Market Issue Charge (9:55-10:20)

Jacob Finkel, with the office of Pennsylvania Gov. Josh Shapiro, will present a proposed *problem statement* and *issue charge* to explore implementing a sub-annual capacity market. (See *Pennsylvania Brings Seasonal Capacity Issue Charge to PJM*.)

The committee will be asked to approve the issue charge.

6. Dual-fuel Capacity Definitions (10:20-10:45)

Dominion Energy's James Davis will review a proposed *problem statement*, *issue charge* and proposal to revise the definition of dual-fuel capacity contained in the Reliability Assurance Agreement (RAA) to include dedicated fuel sources that are not strictly "on-site." (See "Dominion Presents Proposal to Change Dual-fuel Definition," *PJM MRC/MC Briefs: June 18, 2025*.)

The committee will be asked to approve the issue charge and endorse the proposed solution and corresponding RAA revisions. The proposal is being advanced under the quick-fix process, which allows an issue charge to be voted on concurrently with a proposed solution.

7. Storage Integration (Phase II): Transmission Asset Utilization in Operations (10:45-11:25)

A. PJM will review a proposed problem statement and *issue charge* exploring how storage as a transmission asset (SATA) could be operationally implemented.

B. Juliet Anderson of Constellation Energy will present an alternative *issue charge* that includes more consideration of the potential market impacts of SATA.

C. Alex Stern of Exelon will present an alternative *issue charge* to consider both market impacts and the use cases SATA could address.

The committee will be asked to approve one of the issue charges. (See "Stakeholders Bring Alternative SATA Issue Charges, Endorsement Delayed," *PJM MRC/MC Briefs: June 18, 2025*.)

Members Committee

Consent Agenda (3:05-3:10)

The committee will be asked to endorse a consent agenda that includes:

B. proposed *revisions* to PJM's tariff, RAA and OA as endorsed by the Governing Documents Enhancements and Clarifications Subcommittee. The changes include removing outdated references and codifying the second phase of PJM's rules for hybrid resources.

Endorsements (3:10-3:40)

1. Nominating Committee Elections (3:10-3:20)

PJM's Michele Greening will present the sector nominees for the 2025-2026 Nominating Committee. The proposed candidates are:

- Generation Owner: Josh Ghosh, Constellation
- Transmission Owner: Alex Stern, Exelon
- Electric Distributor: Kevin Zemanek, Buckeye Power
- Other Supplier: Noha Sidhom, Viribus Fund
- End Use Customer: Susan Bruce, PJM Industrial Customer Coalition

The committee will be asked to elect the sector representatives upon first read.

2. 2027/2028 Base Residual Auction, Installed Reserve Margin and Forecast Pool Requirement (3:20-3:40)

Bruno will review the recommended IRM and FPR values for the 2027/28 BRA.

The committee will be asked to endorse the values on first read. ■

— Devin Leith-Yessian

Georgia Power to Add at Least 6 GW of Generation

Utility Could Build as Much as 8.5 GW Under Terms of IRP; Green Advocates Criticize Reliance on Fossil Fuels

By John Cropley

Georgia Power will add at least 6 GW of new generation capacity by 2031 under the integrated resource plan approved July 15.

The IRP reflects heavy anticipated increases in demand. The utility had projected up to 8.2 GW of load growth when it *submitted the plan* to the Georgia Public Service Commission in January. (See *Georgia Power Proposes Nuclear Uprate, Delay in Fossil Retirement*.)

The final IRP approved by the PSC (*56002*) directs the 6-GW increase to meet that need and allows a maximum 8.5 GW, if the additional need can be proven.

The IRP also includes:

- a $161 million budget for demand-side energy efficiency programs to help ease the strain on the grid;
- a 10-year transmission plan to include upgrades across more than 1,000 miles of lines;
- nuclear plant uprates;
- modernization of the hydropower fleet;
- upgrades and operating extensions for existing coal and natural gas power plants; and
- a formal process to evaluate new grid-enhancing technologies, both to increase grid capacity and to better integrate solar and storage resources.

The PSC vote to approve the IRP was unanimous. Opinions about the details of the IRP were not.

Environmental advocates and clean energy supporters are unhappy about Georgia Power increasing its reliance on natural gas and coal through upgrades and retirement delays for existing plants.

The Southern Alliance for Clean Energy *called the IRP* "dangerously short-sighted," locking Georgia into a future use of coal and gas that will further burden ratepayers to the benefit of Big Tech — whose data center predictions are speculative and have "significant potential for overestimation of both energy and peak load."

"The strides made in solar, storage and customer programs for clean energy are sadly blunted by the continued investment in fossil fuel infrastructure in the approved IRP," the alliance said. "On top of that, the fact that Georgia Power is authorized to seek certification for up to 8,500 MW of resource capacity after the IRP means there's potential for even more spending on brand-new gas plants on the horizon."

The Clean Energy Buyers Association *was more complimentary* toward the IRP, thanks to the inclusion of a new subscription option allowing commercial and industrial customers to work with developers to bring clean energy projects into Georgia Power's system. The association and the utility collaborated for more than a year on the measure.

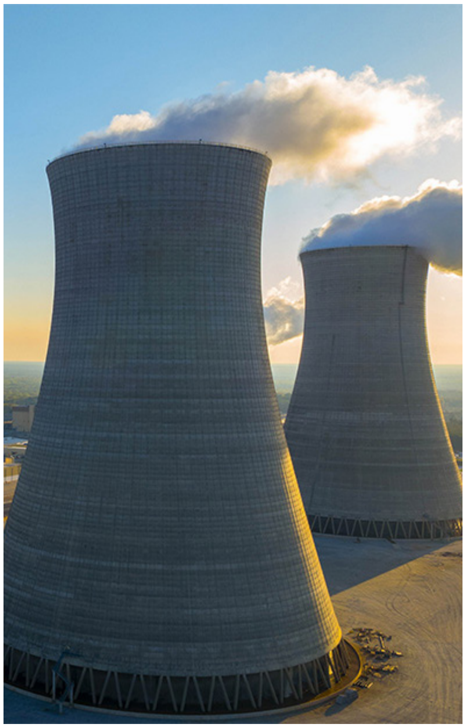
"This is a meaningful step forward in helping customers match their growing energy needs with clean, customer-funded energy resources," the association said.

Renewables are part of the IRP, just not as large a part as some would like.

Georgia Power plans to procure up to 4 GW of renewable resources by 2035, the first 1.1 GW through its competitive Utility Scale and Distributed Generation procurements, and it plans to raise its battery energy storage target above the current 1.5 GW.

The 4 GW of new capacity would bring the utility's renewable portfolio to about 11 GW.

In a July 15 news release, Georgia Power *said its projection* of load growth by 2030 now is 8.5 GW, compared with a *January* projection of 8.2 GW and a 2023 projection of 5.9 GW.



Georgia Power's Plant Vogtle Units 3 and 4 are shown in March 2024. | *Georgia Power*

In its own news release, the PSC noted the internal disagreements over load growth that led to the 6-GW/8.5-GW stipulation: "Georgia Power and the PSC's Public Interest Advocacy Staff disagreed over the amount of new energy large-load customers were expected to consume over the next several years — although both sides did agree it would be significant."

PSC Chair Jason Shaw said: "As data center construction continues in Georgia, this IRP puts us in a safe and secure spot to meet that energy need. This long-term plan continues to strike a balance between reliability and affordability."

Commissioner Tim Echols said: "With unprecedented grid growth ahead for Georgia, this integrated resource plan puts us on the right path to meet everyone's needs. I wish it had more solar, more storage, more energy efficiency — but it strikes a good compromise in the spirit of collaboration."

In the IRP, Georgia Power said components of its generation mix for retail needs in 2024 included natural gas (40%), nuclear (29%), coal (16%), solar (6%), hydro (2%) and wind (1%). ■

Why This Matters

The plan positions the utility to meet anticipated growth from large-load customers and continues its reliance on fossil fuels.

SPP 'Blazes Trail' with Consolidated Planning Process

Three-year Process Marries GI Studies, Transmission Planning

By Tom Kleckner

APA's Steve Gaw has praise for the Consolidated Planning Process. | © *RTO Insider*

LITTLE ROCK, Ark. — SPP stakeholders have unanimously approved a tariff change (*RR684*) that replaces current planning processes with an integrated three-year cycle composed of long-term 20-year and annual 10-year studies the grid operator says could "blaze a trail" for others to follow.

The *Consolidated Planning Process* (CPP) transitions SPP from its "request-then-analysis" framework to a "ready-to-go" construct, where the system needs and costs are identified before the generator asks to connect. It replaces the RTO's separate transmission planning and generator-interconnection studies and aligns system modeling, planning assumptions and cost allocation across load and generation needs.

Too often, said Sunny Raheem, SPP's director of system planning, the current process can lead to separate decisions and determinations and overlook "optimal opportunities for holistic transmission identification."

"This is really aligning cost commitment and collaboration together to aim at the right direction, the right targets and shared costs," Raheem told the Markets and Operations Policy Committee on July 15. "We believe that we're establishing a blueprint under CPP that's going to enable us to plan for the modern era of grid integration. Today, we react to requests showing up; CPP will be proactively planning for guiding them to the positions that we really want the interconnection's request to connect."

Raheem said the CPP sets a 20-year regional transmission vision and forms the basis for its grid-contribution rates. The annual 10-year assessment includes a GI capability study, a GI decision point and a regional assessment that recommends projects for construction, all within three years.

He said the CPP's forward-looking interconnection study and a "levelized" cost calculation based on benefits from using the transmission system make for a robust process. According to SPP's 2025 Transmission Expansion Plan report, 92% of system upgrades are funded by load.

According to a recent *Enverus study*, new SPP operating projects in 2024 spent about six years in the GI queue, about the industry average.

"[The CPP] helps mitigate those binary cost assignment decisions for generator interconnection. It also increases the cost sharing for generators to contribute to transmission upgrades," Raheem said.

MOPC's endorsement — and that expected from the Board of Directors in August — culminates a process that consumed more than 200 meetings, discussions and presentations with eight stakeholder groups over two-and-a-half years. The proposal was endorsed unanimously by every stakeholder group that voted on it. Staff also reached out to educate FERC and SPP's state regulators on the CPP.

"[This journey] may have seemed like a pie-in-the-sky idea that has progressed through incremental policies to get it to this point," Raheem said. "When we're assigning billion-dollar portfolios out of the ITP [Integrated Transmission Planning study], we really need transmission, load and generation all playing together."

Spearmint Energy's Michael Ratliff, while holding reservations as a storage developer, said his company will support the CPP.

"We recognize the need for creative queue reform, the value of creating more cost certainty and spreading the cost of transmission upgrades more evenly across the user base," he said. "We would appreciate some assurances that SPP will be willing to collaborate with developers to make the CPP work for different resource types and the changing resource mix. We're a little concerned that site planning may limit options for energy storage resources and prevent SPP from

Why This Matters

SPP's Consolidated Planning Process combines its transmission planning and GI studies into a three-year process that aligns system modeling, planning assumptions and cost allocation across load and generation needs.

fully realizing the value of storage."

Some of SPP's more outspoken stakeholders praised the grid operator and staff for completing the work in less than three years.

"It is a bright spot for SPP and the stakeholder process," Golden Spread Electric Cooperative's Mike Wise said. "We have had a lot of input over a long period of time, and we have a lot of discussion and a lot of blood, sweat and tears developing this compromise and this approach that can work. We should applaud the SPP staff for sticking with us and managing through this very difficult process, and I am 100% behind it."

"We're here in large part because Sunny and his team and everybody, I feel like on the CPP, really worked hard to try to find a path when we ran into walls, and we did," the Advanced Power Alliance's Steve Gaw said. "Is this the end result? No, we have a lot more work to do on this. Despite the communication that's gone, there's a huge challenge of getting this through at FERC because this is a very different approach than FERC has really seen in the past.

"I think a lot of that groundwork and education that's gone on has been very important," Gaw added. The potential

Sunny Raheem, SPP | © *RTO Insider*

help with load issues is great, he said, if it will "get us to the point where the administrative part of interconnecting both gen and load is no longer the obstacle."

Evergy's Derek Brown, alluding to SPP's now-defunct "evolutionary, not revolutionary" value principle, said he was asked within the company's headquarters whether the CPP process was evolutionary or revolutionary. (See *SPP Embraces Need for Speed to Meet Change Head-on.*)

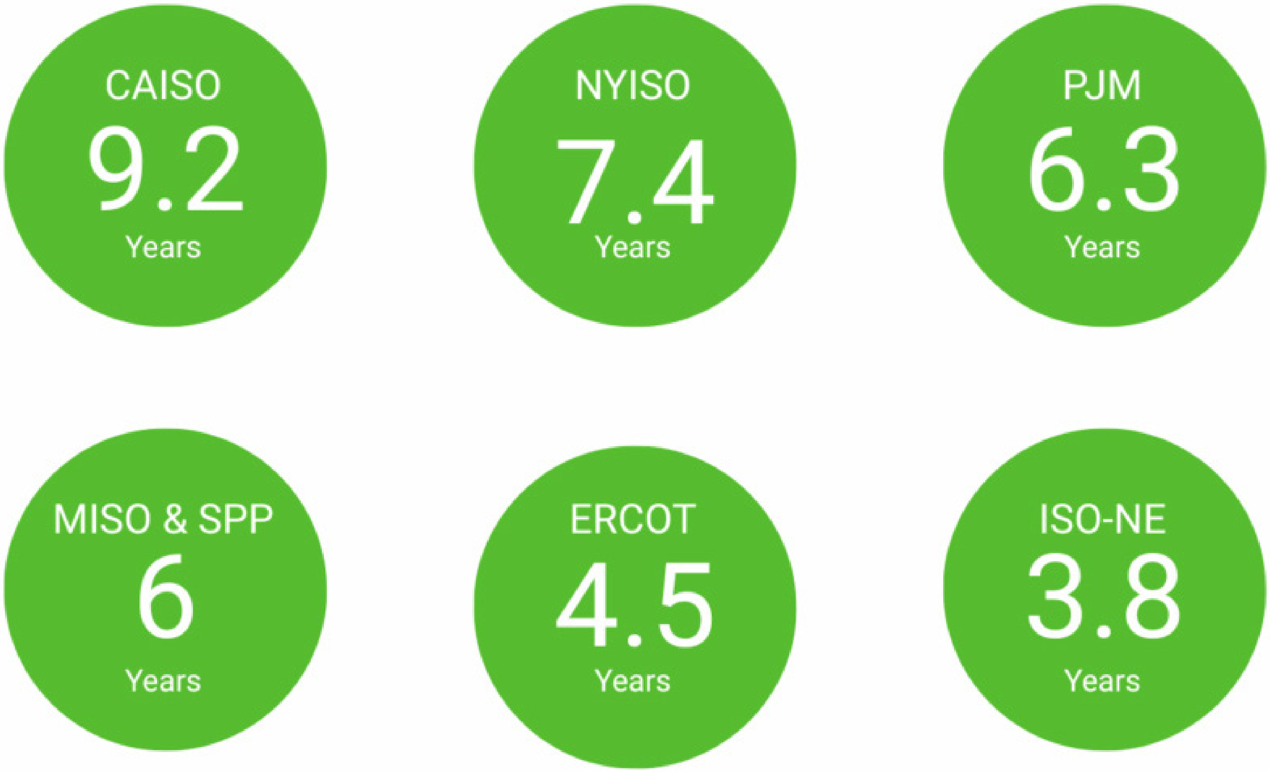
"It is revolutionary, there's no doubt about it. If there was a bright spot for the SPP process, this is it. It took a very long time to get here, to write the tariff language, to take concepts and whiteboard drawings to actual language," said the Transmission Working Group's chair. "But like others said, there's still work to be done."

Brown and other stakeholders will spend the next three months working on the CPP manuals. SPP plans to file the tariff change in the third quarter of 2025. Assuming FERC's approval, the first CPP cluster study will begin in April 2026.

MOPC also unanimously approved the scope and work schedule for a *combined assessment* of the 2026 ITP study, the 2026 20-year evaluation and the CPP transition. The document includes the initial policy items for incorporating the long-term CPP assessment and supports the study to kick off the process.

Staff and stakeholders already have completed model development and a resource plan and siting and set the assessment's futures. They now will begin a second phase, which involves a needs assessment, solutions evaluation and portfolio development.

The scope's CPP technical policies will be converted to planning criteria, the ITP manual, the 20-year assessment manual and GI manual. ■



Queue times for projects in GI queues. | *Enverus*

SPP Adds OG&E's Shuart to External Affairs Leadership

SPP has bolstered its external affairs group in the face of massive industry changes by plucking Emily Shuart from Oklahoma Gas & Electric, where she compiled more than 20 years of experience in federal and state regulatory and legislative affairs, energy policy and stakeholder relations.

Shuart will take over as the RTO's senior director of external affairs and stakeholder relations, effective Sept. 2. She is expected to work closely with Mike Ross, senior vice president of external affairs, in leading SPP's engagement with government officials, legislators, industry organizations and stakeholders.

"Emily brings an outstanding track record of leadership in energy policy and stakeholder engagement," Chief Strategy Officer Kevin Bryant said in a July 17 *press release*. "Her expertise will be instrumental in helping SPP foster productive dialogue with our partners and communicate the value we bring to the region."

OG&E's Emily Shuart is joining SPP's growing external affairs group. | *© RTO Insider*

Carrie Dixon | *SPP*

Shuart, who will report directly to Bryant, most recently served as director of federal, RTO and environmental affairs for OG&E and represented the company on SPP's Members Committee. She holds a bachelor's degree from Baylor University and a law degree from the University of Oklahoma.

The grid operator also promoted Carrie Dixon as technical director, market policy and operations. She will help align the coordination and development of market policies with SPP's goals, tariff and other governing documents amid the evolving national regulatory and industry landscape. The move is effective Aug. 4.

Dixon joined SPP in 2024 and currently serves as market policy principal in support of Markets+. She has more than 15 years of electric utility experience, holding leadership positions at NextEra Energy and Xcel Energy. She represented both companies in various SPP stakeholder groups. ■

— Tom Kleckner

SPP MOPC Briefs

Members Shoot down Staff's Proposal for Integrating High-impact Large Loads

LITTLE ROCK, Ark. — The SPP Markets and Operations Policy Committee resoundingly rejected a proposed tariff change to integrate large loads, pushing back against what some say is a rushed process outside of the normal stakeholder structure.

The committee's decision during its July 15-16 meeting won't stop the revision request (*RR696*) from going before the Board of Directors during its next quarterly meeting Aug. 5. The board in April directed SPP staff to deliver a draft proposal during the meeting that helps integrate large loads, and that includes the "requisite stakeholder engagement." (See "Cupparo Issues 'Executive Order,'" *SPP Board OKs 1-time Study for LREs' Gen Needs*.)

The measure failed with only 53.7% approval. The Transmission Owner segment voted 11-5 for the measure, while Transmission Users voted 24-38. There were 12 abstentions.

"As SPP members continue to receive or — really, in the case of some members — actually submit large load requests to us, we've needed to develop an effective policy that allows our members to be both responsive and competitive in the pursuit of these loads," COO Antoine Lucas said in setting up the discussion, which ate up much of the meeting's two days.

Antoine Lucas, SPP | © *RTO Insider*

"The *large load policy* is essential to responsibly allow this new industrial-scale electricity demand such as AI, data centers, advanced manufacturing and even energy-intensive production processes to integrate and operate," he added.

SPP says its 2025 Integrated Transmission Planning assessment includes about 10 GW of large loads, with an average size of 235 MW. The 2026 ITP includes more than 20 GW of large loads.

The grid operator's solution addresses gaps in current planning processes that have resulted in long wait times for projects, a lack of flexibility for limited connection or operation of load with system limits and cost uncertainty for transmission upgrades.

The proposal is built around 90-day studies that allow faster load connection with certain reliability-driven conditions. The policy defines several large-load types or services, including:

- high-impact large loads (HILLs): any commercial or industrial individual load facility or aggregation of facilities at a single site, connected through one or more shared points of interconnection or points of delivery that can pose reliability risks to the grid. HILLs are nonconforming loads of either 69 kV or below with a peak demand of 10 MW or greater, or greater than 69 kV with a peak demand of 50 MW or more.
- conditional high-impact large load (CHILLs): the portion of a HILL that is receiving conditional high-impact large load service (CHILLS). This is intended for any HILL specifications that cannot be reliably served on a firm basis by existing designated resources or the current transmission system. CHILLs can exist at the same delivery point as firm load.
- CHILLS: a new transmission service available to HILLs to transfer energy to designated points of delivery to serve a transmission or network customer's CHILL. The service will be available for yearly periods ranging from one to five years.

"HILLs, CHILLs and thrills," cracked one wag at the table.

"A big principle in this is to have a path to firm service and balanced reliability," said Casey Cathey, SPP's vice president of engineering. "Our solution is to be the fastest connection study in the United States. We've looked at all of our fellow ISOs and RTOs. We work with them at least quarterly and share best practices. We also looked at Southern Co. We looked at a number of different areas that are challenged with similar challenges. … We want to provide transmission customers all the options necessary in the toolbox." (See *SPP Embraces Need for Speed to Meet Change Head-on*.)

SPP said the rules for large load's cost allocation are consistent with the existing tariff and aim to minimize cost shifts from HILLs and CHILLs to other customers, aligning costs with those causing the upgrades. Those costs are directly assigned to the large-load customer until it secures firm service and is potentially eligible for base plan funding.

CHILLS is billed on reserved capacity megawatts. If curtailed, charges adjust to the curtailed megawatts.

In opening the second day of discussion on large loads, CEO Lanny Nickell

SPP's Casey Cathey (left) confers with CEO Lanny Nickell as debate over large loads continues. | © *RTO Insider* expressed the need for speed and stakeholder input. To bolster his case, he said a person could draw circles around any 14 contiguous states in the country — as he did — and they would find more data centers in that region than in SPP's 14-state service territory.

Quoting ChatGPT, Nickell said the lost opportunity of a more-than-$1 billion capital investment for a 100-MW load amounts to more than the $1 billion: It also results in $200 million to $500 million lost construction and ongoing jobs, $50 million to $150 million of lost tax revenue over 10 years and $25 million to $75 million of lost grid and system value.

"That's the pure evidence. That's the pure data," he said. "That's not something I really want to go to the governor and say, 'You know what? Because we couldn't get this done in a timely fashion, you just lost another 100 MW.'

"It was made clear to me several months ago [by members' leadership] that this is an opportunity that we have to take advantage of, and if we don't, it's not only hundreds of millions to billions of dollars of lost opportunity if we don't take advantage of this. It turns into a threat to our long-term existence. So that's why we're doing this, and that's why this is urgent, and that's why we're doing it as fast as we can, but we still are trying to do it in a way that considers as much input as we can possibly get. We want every piece of input that we can get."

Over two days, including a half-day education session on large loads, SPP got that input.

"My background has always been in operations, and I have extreme concerns about the reliability impacts of large loads. I don't think we've thought of all the potential issues that can come from bringing these large loads on," NextEra Energy's Jeff Wells said, calling for more time. "I'm not saying we need three months. I'm not saying we need six months, but we need time to go to our experts in SPP that aren't SPP employees. … We need to get their feedback, and we need to make sure that we've addressed all those concerns."

The Advanced Power Alliance's Steve Gaw said SPP has not followed its stakeholder process. Members, some constrained by a lack of internal resources, have struggled to keep up as the policy and revision requests are developed at the same time.

"There's a reason why we need to prioritize things," he said. "There are lots of investment dollars that have been lost because of road blocks to getting generation interconnected over the last several years. We would not have the same kinds of problems in having resources to match this load if we had done some additional work to prioritize things in that fashion as well."

Gaw also complained about the little time stakeholders have had to comment on the proposal's "*500-plus pages* that were dropped on us" in late June.

Noting that additional comments to the board on the tariff change are limited to two pages, Western Farmers Electric Cooperative's Matt Caves asked whether the directive could be reciprocal.

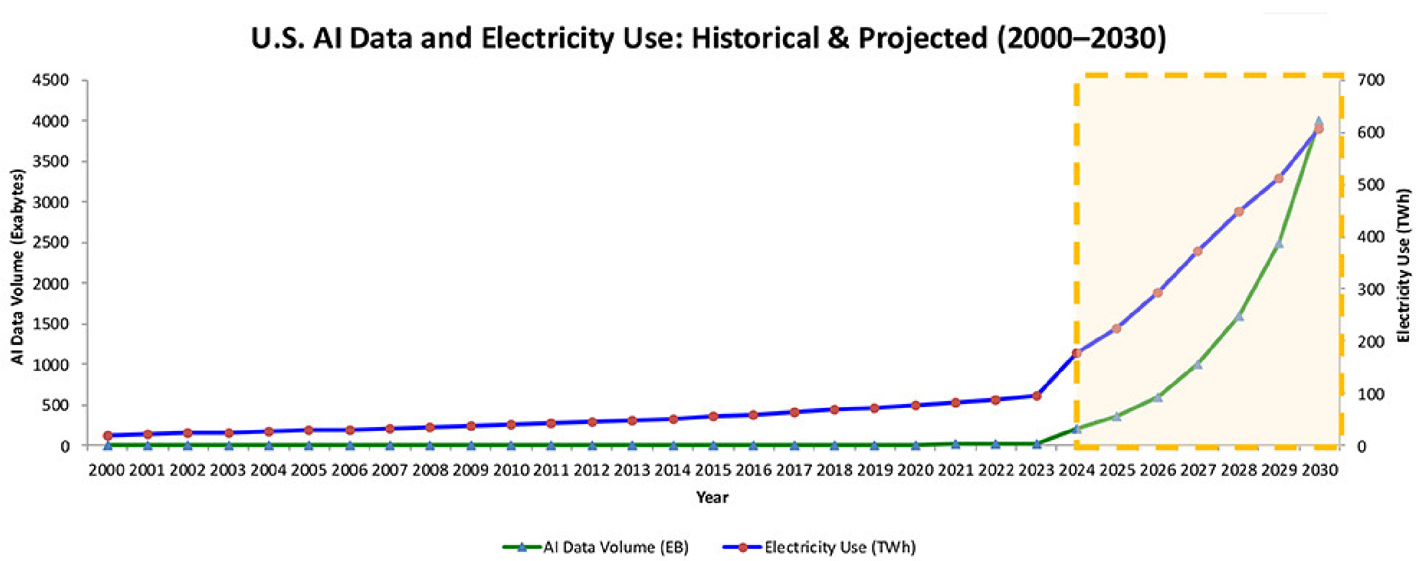
"Can SPP reduce this RR to, say, 100 pages?" he asked, drawing chuckles from staff and stakeholders.

Olivia Hough, a regulatory strategist with City Utilities of Springfield in Missouri and MOPC's vice chair, said the utility has formed a task force to go over the "voluminous" document.

"It's a lot to go through, and I understand that everyone maybe can't read every single line item of it," she said. "In whole, we want to see this move forward. We don't want to miss out on the opportunity, and we think that the economic development potential and the challenge is worth it. I appreciate SPP's commitment to putting this together at the same time that all the utilities are trying to develop their own frameworks."

"This is what SPS has been asking for: help to serve loads," Southwestern Public Service's Jarred Cooley said. "We really see that this is something that needs to be done. … We get the opportunity to get in front of FERC, get that feedback, figure out maybe what changes we need to make in the next iteration, and continue to push forward."

SPP's Market Monitoring Unit also weighed in, saying that despite a "high level" of engagement with the RTO, it still has concerns that the proposal introduces risk to the market and other participants. It recommended risks be mitigated before any implementation and said



SPP slide showing growth of data centers in recent years | *SPP* it may identify additional risks and make further recommendations in the future.

MOPC passed a motion to hold a special workshop and further consider RR696 no later than the end of September. The motion passed with 69.9% approval.

COO Lucas emailed MOPC's membership on July 18, laying out the several channels open to stakeholders who want to continue shaping the proposal before it goes to the board. SPP followed the email with a survey that members can use to share their concerns and recommended solutions.

Members can also provide "high-level, strategic feedback" directly to the board. The feedback, using a template to ensure consistency and focus, is due July 28, the same date the grid operator is keeping the comment period open for RR696. Several working groups will each review the proposal during their scheduled meetings before Aug. 5.

"Your continued participation in this process is valued and vital," Lucas wrote. "You have our continued commitment to incorporate our stakeholders' diverse perspectives as thoughtfully and equitably as possible. With your help, we aim to bring a proposal to the board that reflects both the urgency of this issue and the collective wisdom of our stakeholders."

Seams Cost Allocation Rejected

MOPC also rejected a proposed tariff change *RR681* that would provide a cost-allocation mechanism for projects that don't qualify as interregional projects and where SPP shares cost with one or more neighbors. The measure received only 54.9% approval.

Aaron Shipley, the RTO's senior interregional coordinator, said the proposal would make the process of building future jointly funded projects more efficient. He said it would be helpful to have the tariff change in place as SPP moves forward with the RTO's Western expansion.

"We would expect to receive efficiency in our processes by having this cost-allocation tariff mechanism already approved and thus eliminating individual at-the end-of-the-process cost-allocation debates that we have all been through before and provide significant risk at the end of a project and process," he said. "This is something we've heard support from both stakeholders and regulators all the way from the beginning of this effort."

SPP's membership first raised the issue in 2014, and it was later readdressed and confirmed through the *Strategic and Creative Re-engineering of Integrated Planning Team*'s (SCRIPT) work in 2020-2021. The RTO's state regulators in October 2024 endorsed a seams policy white paper and directed staff to move forward with a recommendation to seek FERC approval.

Stakeholders pushed back against RR681 over concerns the seams projects would be subject to the grid operator's competitive process screening. They wondered whether staff would be able to take on the number of new planning processes feeding into the process.

"I'm not opposed to following this kind of process in general," American Electric Power's Richard Ross said. "I'm opposed to just automating it so that it's just there all the time. I think there may be some serious instances where we do things in one area that really don't have greater benefits across the region, and so they ought to be allocated more. I do hope you will share with me that we ought to take a closer look at these on an individual basis."

From left: SPP's Chris Nolen, Natasha Henderson listen to Yasser Bahbaz during a panel on demand response. | © *RTO Insider*

3 RRs Endorsed

Members endorsed three other revision requests with varying levels of approval.

RR693 received 76.5% approval, with SPS the only transmission owner of 17 to vote against it. The first phase of *Surplus Plus* and its suite of initiatives designed to accelerate the addition of new generation, the measure would quickly add shovel-ready incremental capacity at existing generating sites. The process would end when the Consolidated Planning Process begins in 2026. (See related story *SPP 'Blazes Trail' with Consolidated Planning Process*.)

Under the proposal, priority requests would be queued higher than study clusters that haven't started. The process would be conducted on an accelerated time frame, not subject to waiting for open seasons or processing as part of a cluster or from needs driven by other requests.

Assuming FERC approval in October, the first requests would be submitted for a 90-day system impact study, with the first GI agreements issued by April 1.

RR693 was an outgrowth of discussions at the Resource and Energy Adequacy Leadership (REAL) Team, said Steve Purdy, SPP's technical director of engineering policy.

"It is another tool in the toolkit for customers to be able to add new generation to the system, in addition to all of the existing processes that customers have available to them," he said. "It's a new process that will allow a customer to make a request and submit that outside of the DISIS [definitive interconnection system impact study] window."

RR689, which passed with 95.8% approval, was opposed only by four members of the Transmission Users segment. The proposal would reject market participant bids in the transmission congestion rights (TCR) market when sourcing from an electrically equivalent settlement location (EESL) to another settlement location on the system, or when the participant adds another bid from a settlement location back into the original EESL group that sinks at a different settlement location than the source.

"We saw some concerning TCR bidding strategies in the TCR market," said Micha Bailey, SPP's manager of congestion hedging. "[EESLs] don't have to be co-located, but electrically equivalent settlement locations basically have what we like to call unconstrained flow between them. So, you can basically get an infinite amount of TCR awards."

The MMU's Raleigh Mohr said the Monitor was supportive of the measure.

"Essentially, the message is this behavior is bad. FERC has ruled in other markets and in our market that this behavior is manipulative. We wanted to make sure that at this full representation body, that everyone heard that message," he said.

A motion to include comments from The Energy Authority (TEA), speaking for six market participants, failed with only 35.8% approval. TEA recommended restricting implementation to auction revenue rights (ARRs) submitted for self-conversion to TCRs and not applying the restrictions to settling ARRs.

"Our general principle is if a gaming opportunity exists and it can be closed, then it should be closed," Mohr said, arguing against TEA's comments.

RR676 came within a percentage point of unanimous approval, receiving its only opposing vote from NG Renewables Energy Marketing. The measure creates a process for studying electric storage resource loads subject to SPP's generator interconnection process and ensures compliance with FERC Orders 845 and 2023 and NERC reliability standard FAC-002-2.

"Today, our studies assess them for injection as a resource," Evergy's Derek Brown said. "One of the reasons for the enhancement is to better assess the impacts of these electric storage resources."

The RTO currently has 179 active storage projects, totaling 31 GW, in the queue.

"We just think this is a crucial step forward for ensuring reliability and compliance of ESRs within the SPP transmission system," Eolian's Kyle Martinez said. "This is generation that can come online [and] provide ancillary service products off of the market."

DR Policy Endorsed

MOPC endorsed SPP's demand response and load-responsible entity peak-demand assessment policy proposals, designed to help ensure realistic forecasts that reflect the effect of flexible load.

Members amended the original motion to direct staff to prepare an RR based on the DR policy framework and conduct stakeholder reviews in conjunction with the LRE peak-demand assessment policy and RR.

Assuming their eventual approval, SPP plans to file both tariff changes together at FERC in early 2026 because of the "interdependency" between the two. A joint filing would provide a single, transparent foundation for resource adequacy and tariff evolution, staff said.

The DR framework includes various metrics, criteria and thresholds for both reliability and market-registered DR to reduce consumption during tight grid conditions.

The REAL Team approved the policy earlier in July during a special meeting. (See *SPP REAL Team Endorses Demand Response Framework*.)

Consent Agenda Passes

MOPC endorsed *RR692* by more than 91% approval after it was pulled from the consent agenda over timing concerns.

The change allows multiple Phase 1 restudy iterations within the DISIS process in the face of growing interconnection clusters. The 2024-001 cluster has 380 requests totaling more than 100 GW of capacity, almost double the size of the previous largest cluster.

"We're seeing large amounts of dropouts between phases. Customers are being asked to make decisions about moving to the GIA portion of the DISIS analysis before we really have an understanding of what customers are going to remain when we're through the entire process," SPP's Natasha Henderson said. "What's proposed here is that we add additional Phase 1 studies. For instance, if 30% of the projects drop out in Phase 1, we would repeat Phase 1 again if we're going to Phase 2, which adds stability to the mix."

The measure received 91% approval from members.

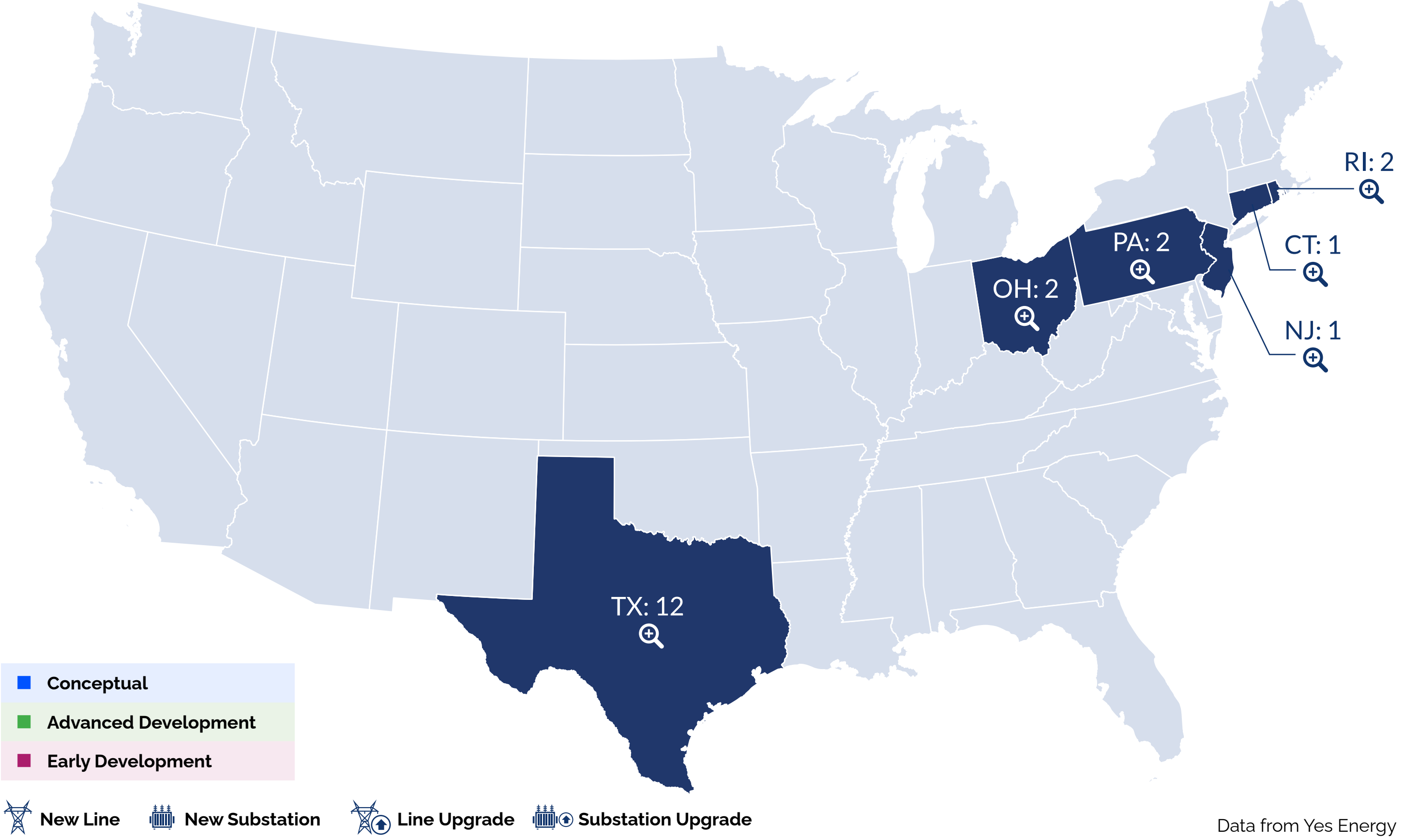
The consent agenda included eight other revision requests that, if approved by the board, would:

- *RR675*: modify the local market power test for resources in a nonbinding frequently constrained area.
- *RR677*: add language that was inadvertently omitted from the settlement calculations changes approved in *RR628* (Price Formation) that checks whether a resource is below its day-ahead market position.
- *RR678*: remove outdated references to quick-start resources, which have been replaced by fast-start resources, from the protocols because of updates in registration parameters.
- *RR679*: revise the ITP manual to remove conflicting language and references to the Model Development Procedure Manual's new process. The new method allows for more data points to be included in calculating the number used for renewable resource dispatch, resulting in increased accuracy and confidence in the base reliability model.
- *RR680*: establish the incremental market efficiency use (IMEU) mechanism to provide revenue that offsets the increased operational costs of the West DC ties because of more frequent market-directed dispatches under the five-minute market.
- *RR683*: clarify and align governing document language with actual operational practices for notifying market participants during emergency conditions, including cleanup edits and new language allowing operations to issue notifications as soon as practical when emergencies are anticipated.
- *RR685*: update the Integrated Marketplace rules to allow SPP's Western balancing authority area to join the Western Power Pool's Reserve Sharing Group, lowering ancillary service costs and strengthening system reliability.
- *RR691*: revert tariff language back to its correct verbiage regarding changes for the RTO's Western expansion. ■

— Tom Kleckner

T&D Projects Added in the Past Week

YES ENERGY



Data from Yes Energy

Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	Endpoint 1 / 2
Canterbury - Tunnel Line New Switching Station	Eversource Energy	Connecticut Light and Power	115	2028	CT
McCarter New Switching Station	PSEG	PSEG	230	2029	NJ
Wayne-Madison New Substation Station	Duke Energy	Duke Energy Ohio, Inc.	345	2028	OH
Cotton Run New Substation	Duke Energy	Duke Energy Ohio, Inc.	345	2029	OH / OH
Crossland - Sharon 138 kV Z-112 New Line Tap	FirstEnergy Corp.	ATSI	138	2027	PA
Blaschak New Tap	PPL Corp.	PPL Corp.	69	2026	PA
North Kingstown New Switching Station	PPL Corp.	Rhode Island Energy	115	2028	RI
Tonkawa Switch - Hermleigh Sync Con New Tie Line	Sempra Energy	Oncor Electric Delivery	345	2026	TX
Expanse Switch - Lenorah POD New Tie Line	Sempra Energy	Oncor Electric Delivery	138	2026	TX
Little Sale Ranch New Substation	Sempra Energy	Oncor Electric Delivery	138	2026	TX
Charles Hall New Substation	Sempra Energy	Oncor Electric Delivery	138	2025	TX
Rhine Lake New Substation	Sempra Energy	Oncor Electric Delivery	138	2025	TX
Quaid New Switching Station	Sempra Energy	Oncor Electric Delivery	138	2026	TX
Baines Creek New Switching Station	Sempra Energy	Oncor Electric Delivery	138	2026	TX
Token POD (Ben Davis - Allen Switch)	Sempra Energy	Oncor Electric Delivery	138	2025	TX / TX
Cloud POD (Allen Switch - Richardson East)	Sempra Energy	Oncor Electric Delivery	138	2025	TX / TX
Possum Kingdom New Substation	Sempra Energy	Oncor Electric Delivery	138	2025	TX / TX

Company Briefs

BP Agrees to Sell U.S. Onshore Wind Business to LS Power

BP last week announced it will sell off its onshore wind business in the U.S. to LS Power.

BP will sell its share of 10 wind farms in the process. The value of the wind farms, nine of which are operated by BP, is understood to be lower than the $2 billion valuation estimated for BP's onshore wind business in the past.

The sale is part of BP's plan to offload $20 billion in assets "to simplify and focus the business" after a failed attempt to reinvent itself as a net-zero company.

More: *The Guardian*

Rivian to Open Atlanta HQ as it Prepares Nearby Factory

Rivian last week announced it is establishing its East Coast headquarters in Atlanta later this year to support operations at its second EV plant, which is set to begin construction in 2026.

Later this year, Rivian will occupy the top floor and the lobby of the Junction Krog District building east of downtown with about 100 employees to start. The employee count will rise to around 500 over time, the company said. Rivian's main headquarters is in Irvine, Calif.

Rivian plans to begin construction on its $6 billion Georgia factory in the Stanton Springs industrial park next year.

More: *Yahoo Finance*

Primergy Solar, Microsoft Activate Ash Creek Solar Project

Primergy Solar last week said that its 408-MW Ash Creek solar project in Hill County, Texas, has reached commercial operations.

Primergy, which acquired the project in 2021, has a long-term power purchase agreement with Microsoft. The project will also add capacity to the ERCOT grid.

More: *pv magazine*

Federal Briefs

Trump Dismisses 7 from Nuclear Waste Oversight Panel

President **Donald Trump** last week dismissed all but one of the members of the Nuclear Waste Technical Review Board, diminishing oversight of the country's long-term spent nuclear fuel storage program.

The White House sent emails to seven board members — Richelle Allen-King, Miles Greiner, Silvia Jurisson, Nathan Siu, Seth Tuler, Scott Tyler and Brian Woods — dismissing them from the board, effective July 16.

More: *E&E News*

EPA Eliminates R&D Office, Begins Layoffs

EPA last week announced it is eliminating its Office of Research and Development and reducing agency staff by thousands of employees.

The agency said it will create a new Office of Applied Science and Environmental Solutions.

Meanwhile, staffing will decrease to 12,448, a reduction of more than 3,700 employees (23%) from staffing levels in January.

More: *CNBC*

EPA Delays Required Cleanups of Toxic Coal Ash Landfills

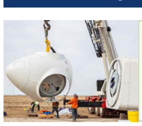
EPA said last week that it would give utility companies an additional year to begin cleaning up contamination from toxic coal ash landfills across the country.

Under a rule finalized by the Biden administration last year, utilities had until February 2026 to report to EPA any contamination from their coal ash landfills. They had until May 2028 to install groundwater monitoring systems and to start drafting plans for cleaning up the contamination.

The agency said it would extend these deadlines by at least a year, until February 2027 and August 2029, respectively.

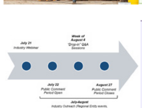
More: *The New York Times*

National/Federal news from our other channels



LS Power to Buy bp's U.S. Onshore Wind Business

NetZero Insider



NERC Task Force Members Share Standards Modernization Progress

ERO Insider

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

State Briefs

ALABAMA

Beeker to Seek Full Term on PSC

Public Service Commissioner **Chris Beeker III** (R) announced last week he will run in next year's election for a full, four-year term on the commission.

Beeker III was appointed by Gov. Kay Ivey in 2024 to serve the remaining term of his father, Chris "Chip" Beeker, who resigned from his seat because of health issues.

The younger Beeker served for four years as the U.S. Department of Agriculture's rural development director for the state in the first Trump administration. The 2026 primary election is May 19.

More: *Alabama Daily News*

GEORGIA

Hubbard Wins Democratic PSC Primary Runoff

Peter Hubbard, a clean energy advocate, secured the Democratic Party nomination for the Public Service Commission District 3 seat last week over former Atlanta City Councilwoman Keisha Sean Waites.

Hubbard's victory was thanks to more than 18,000 votes over Waites, who won 47% of the vote in the initial primary in June. Hubbard had come in second place.

Hubbard will face incumbent Commissioner Fitz Johnson (R) in the general election Nov. 4.

More: *Georgia Recorder*

ILLINOIS

Towns Considering Contract Extensions with IMEA

Naperville and St. Charles are considering whether to extend their contract with the Illinois Municipal Electric Agency for another 20 years when their current contracts end in 2035.

The towns are three of 32 member communities that have yet to sign an extension. The deadline to do so is Aug. 19.

Some residents have raised concerns over IMEA's reliance on Prairie State Energy, a coal-fired plant. Others say it lacks transparency and locks Naperville into rates for 20 years without competition. Meanwhile, proponents say IMEA offers the cleanest energy portfolio option for the city.

More: *Daily Herald*

IOWA

Groups Say Coal Plant Seeking 'Unlawful' Wastewater Permit

Several environmental groups are urging the Department of Natural Resources to deny a wastewater permit for the Ottumwa Generating Station because, they say, it "unlawfully" avoids federal guidelines for coal combustion leachate discharges.

DNR and Alliant Energy, which owns the plant, say the permit request updates a "technical issue" from a previously issued permit, and the federal guidelines in question cannot be upheld because the station does not discharge leachate.

Sierra Club Iowa Chapter, Iowa Environmental Council, and the Environmental Law and Policy Center submitted comments on DNR's published draft permit for the plant and urged the department to require supplemental information from Alliant to "meet the requirements of the Clean Water Act."

More: *Iowa Capital Dispatch*

MARYLAND

State Fires Back About Offshore Wind Permit

The state Department of the Environment is defending the permit it issued to a wind farm proposed off the coast of Ocean City after a challenge from EPA.

EPA had contended that when the state issued the permit to US Wind, it identified the wrong process for citizens to file appeals. But Environment Secretary Serena McIlwain said the state would not be reissuing the permit, as EPA requested, because it had not made a mistake that needed correcting.

The department also maintains that any appeal of the permit would need to go through the appropriate state circuit court, in this case in Worcester County. The deadline for appeal, however, was July 14. "Long-settled procedure dictates that state-issued permits are appealed under state law, not federal law," McIlwain wrote.

More: *Maryland Matters*

TEXAS

Texas Gas Service Files for 3rd Rate Increase in 12 Months

Texas Gas Service last week filed for its third rate increase in approximately 12 months, seeking to raise $41.1 million in revenue.

Under the new proposal, small residential customers would see their bills climb from $21.36 to $29.50/month. Large residential customers would increase from $33.36 to $39.50/month.

The Austin City Council is expected to approve a 90-day delay of the proposal, though the city has limited authority to block it. The city does not own its gas utility and cannot control its rates. Final approval lies with the Texas Railroad Commission.

More: *Austin Monitor*