ISSN 2377-8016 : Volume 2025/Issue 34 ▪ August 26, 2025

YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

MISO | FERC/FEDERAL

DOE Orders Mich. Coal Plant to Remain Available Another 90 Days

Newkirk Electric Associates

The order is another move by the Trump administration to use aging fossil generation to shore up the grid. But MISO again stressed that the J.H. Campbell plant did not clear the planning resource auction and is unnecessary for resource adequacy in the 2025/26 planning year.

CONTINUED ON P.38

ISO-NE

Siemens Gamesa

BOEM Slaps Stop-work Order on Revolution Wind (p.33)

The move is the latest and one of the most drastic steps by the Trump administration to thwart wind power development.

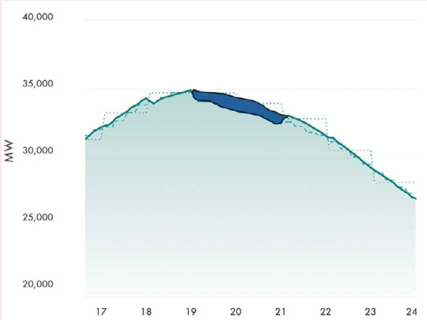
PJM

© RTO Insider

PJM Stakeholders Reject Proposals to Rework Accreditation (p.48)

Stakeholder perspectives on the proposal were mixed, with many arguing there is not sufficient understanding of how ELCC functions nor the outcomes the proposed changes might have.

AROUND THE CORNER



CAISO

The Era of Virtual Power Plants Finally May Be Here (p.5)

Keeping the lights on in the decades to come may in part depend on how quickly these virtual power plant resources become a normal part of our electricity landscape.

COUNTERFLOW

In this week's issue

Have You Heard the One About New Jersey Leaving PJM?

By Steve Huntoon

Steve Huntoon

Yeah, that one. *The Wall Street Journal*'s op-ed broadside on Gov. Phil Murphy, New Jersey and PJM.

We'll get to the punchline later, but let's start with some reality checks.

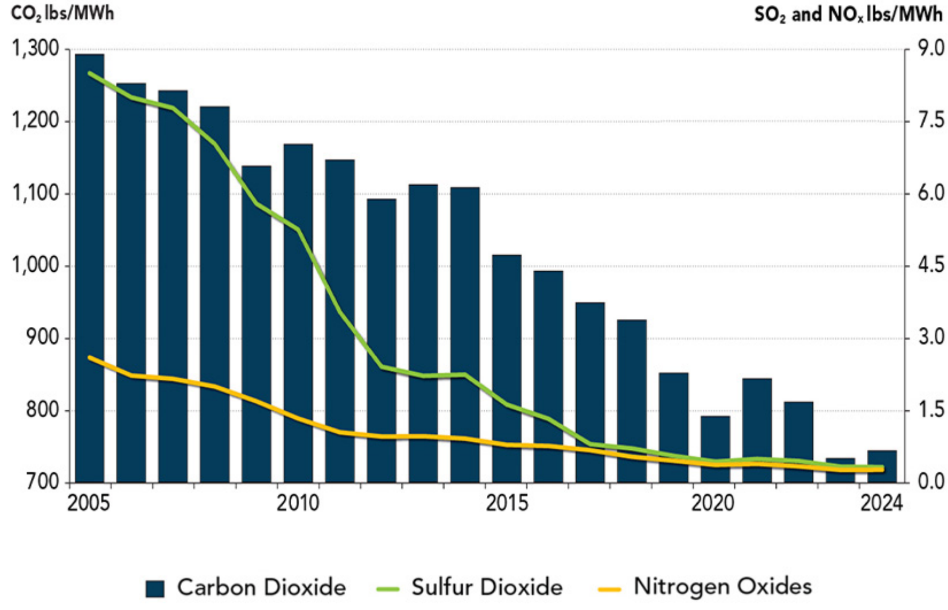
Reality Checks

Energy independence in the past? Here's the op-ed claim: "By 2016, New Jersey achieved energy independence … partially fueled by Pennsylvania gas." That is a plain contradiction in terms. Not to mention that New Jersey's gas power plants are *totally* fueled by out-of-state gas.

And, come to think of it, I haven't noticed any uranium mines in New Jersey that could fuel New Jersey's nuclear plants.

And even if the op-ed claim was meant to refer to New Jersey power plants (not their fuels), it's still wrong: In 2016, New Jersey had 16,797 MW of generation capacity and 19,012 MW of peak demand (Slides 7 and 25), so New Jersey wasn't "energy independent" no matter how you look at it.

Coal plants shut down? How about the op-ed claim that New Jersey "shut down" all its coal plants? Coal plants in New Jersey shut down *voluntarily* because of poor economics, with the last of them, Logan and Chambers, shutting down in 2022.

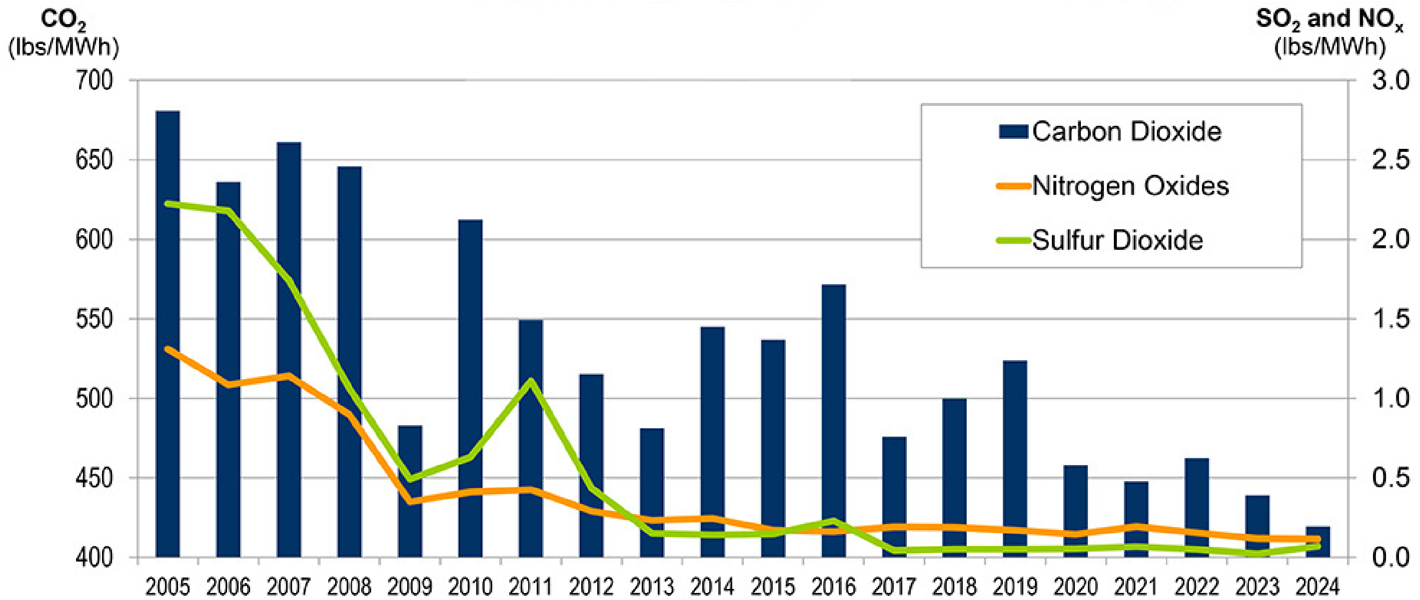


PJM system average emission rates | *PJM*

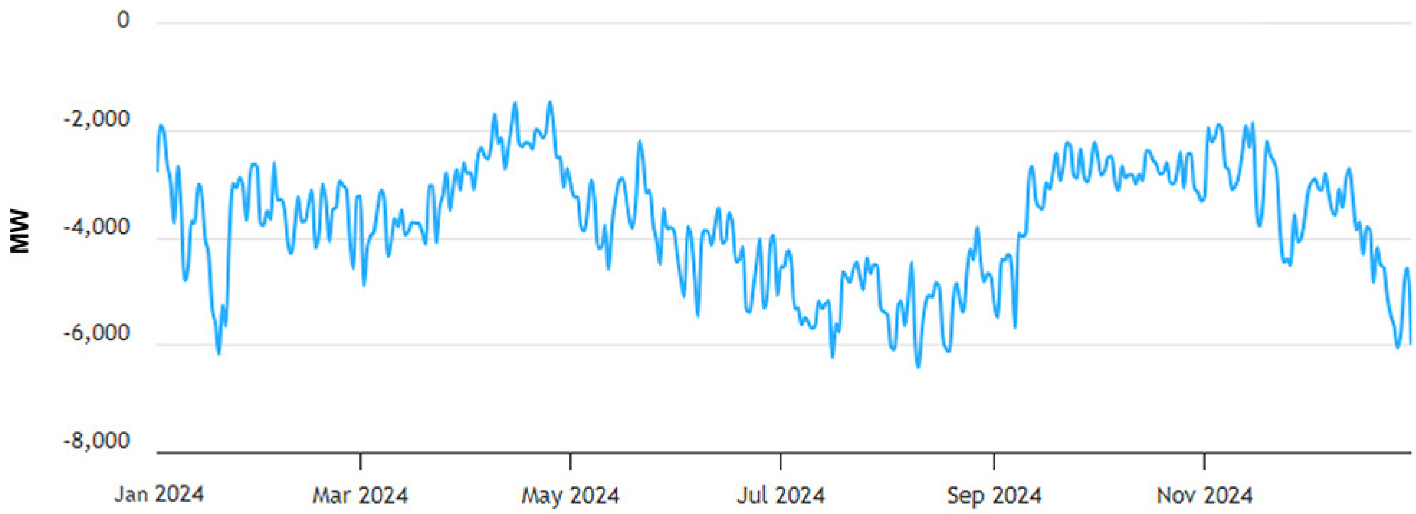
Increased reliance on wind and solar? The op-ed claims that New Jersey has "increased its reliance on intermittent wind and solar power." Actually, solar power has had a trivial increase from 117 MW to 181 MW, and wind power has changed, a la Mr. Blutarsky, from zero-point-zero MW to zero-point-zero MW. (See Slide 7 and Slide 8.) So much for facts.

Supply-side mismanagement? New Jersey is alleged to have had supply-side mismanagement leading to a 12% decrease in generating capacity. That is a *smaller* decrease than the regional decline of 20% that the op-ed claims later.

Blue-state PJM? Then there's the claim that PJM has had the same bad policies as New Jersey because PJM's "leadership" is driven by its "largely blue-state makeup." This claim is baffling on multiple counts. PJM is not governed by states' political leadership — instead by an independent board and "stakeholders" like retail customers, generators and utilities.



New Jersey average emissions | *PJM*



New Jersey net energy import/export trend | *PJM*

PJM is regulated by FERC. PJM states are not even "largely blue" — the legislatures are divided evenly, six red, six blue and two split, between its 13 states and the District of Columbia. With legislatures and governors considered it's four red, five blue, and five split.

Facts are stubborn things.

What Actually Happened?

So what actually happened over the past 10 years? Low wholesale energy and capacity prices incented inefficient generators (mostly coal) to retire in New Jersey and across PJM. And they did. The PJM markets served consumers well, as summed up in a New Jersey BPU report: "The regional competitive market has performed well in offering secure, low-cost supply to New Jersey." (*See Page 9*.)

The New Jersey average residential rate increased by 23.3% from 2016 to 2024 (less than 3% per year).

Data from the same Energy Information Administration chart shows that residential rates in the rest of PJM increased by an average of 27.9% over this same period. So the New Jersey rate increase was less than the rest of PJM. And the residential rate increase in the U.S. overall was 31.3% — so the New Jersey and PJM increases were both less. Please check out the numbers yourself.

And, as a bonus, emissions in PJM have declined dramatically, as this chart shows. (See Slides 31 and 32.) Even if you don't care about carbon emissions and global warming, you should at least welcome the amazing declines in nitrogen oxides and sulfur dioxide.

Now we're in a new supply-demand situation from data centers driving big increases in forecasts of future demand. (*See Slide 20*.) This is increasing capacity prices. The higher prices are designed to attract new generation to meet that future demand. It's that simple. And though tough challenges loom, including higher residential rates, thus far it's working as designed.

By the way, something else you'd never guess from the op-ed: The capacity price increase for New Jersey is no less than that for the rest of PJM.

Leaving PJM

Now that we understand the fundamentals of where we were and are, let's consider the op-ed's punchline that New Jersey should leave PJM, and go it alone.

Hmm. New Jersey has 13,388 MW of generation capacity and 21,221 MW of peak demand. (*See Slides 8 and 21*.) So it's short 7,883 MW.

Here's the chart of New Jersey's electricity imports to meet customers' needs. (*See Slide 28*.) You'll notice that imports vary between 2,000 MW and 6,000 MW throughout the year. That means that if New Jersey left PJM to be on its own, there would be rolling blackouts around the clock, varying from 9% of New Jersey households to 28% of New Jersey households. Brilliant!

New Natural Gas and Nuclear to the Rescue?

The op-ed goes on to suggest that New Jersey could avoid shortages and blackouts with new natural gas and new nuclear generation. Sorry, no.

The op-ed says new natural gas plants could be delivered in New Jersey within three years — that's not only wrong, but irrelevant. New natural gas *supplies* couldn't be delivered to New Jersey for 10 years at best, as this timeline for the Northeast Supply Enhancement project illustrates. The last pipeline project proposed to serve New Jersey, the PennEast Pipeline, was proposed in 2014; targeted completion became 2023 before it was abandoned in 2021. So good luck with that.

New nuclear is even further off, not to mention prohibitively expensive (before cost overruns), as I've discussed before. As Brattle recently advised the New Jersey BPU: "If it chooses to embark on an ambitious new nuclear strategy, New Jersey may have a new, probably small, nuclear unit online by the late 2030s or 2040." (*See Page 6*.) Oh boy, one small nuclear unit in 15 years or so. And good luck with the siting, especially in northern New Jersey, where the new generation would be needed.

The Upshot

New Jerseyites would suffer through many years of rolling blackouts, wondering why *The Wall Street Journal* promoted leaving PJM. ■

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

The Era of Virtual Power Plants Finally May be Here

Peter Kelly-Detwiler


Peter Kelly-Detwiler

On July 29, at 7 p.m., California's three investor-owned utilities, in partnership with SunRun and Tesla, orchestrated the largest activation to date of customer-sited batteries across 100,000 locations.

Within seconds, *539 MW of power from this aggregated virtual power plant* (VPP) was flowing back into the grid, reducing peak evening demand. This may have been the largest demonstration of its kind to date. It won't be the last.

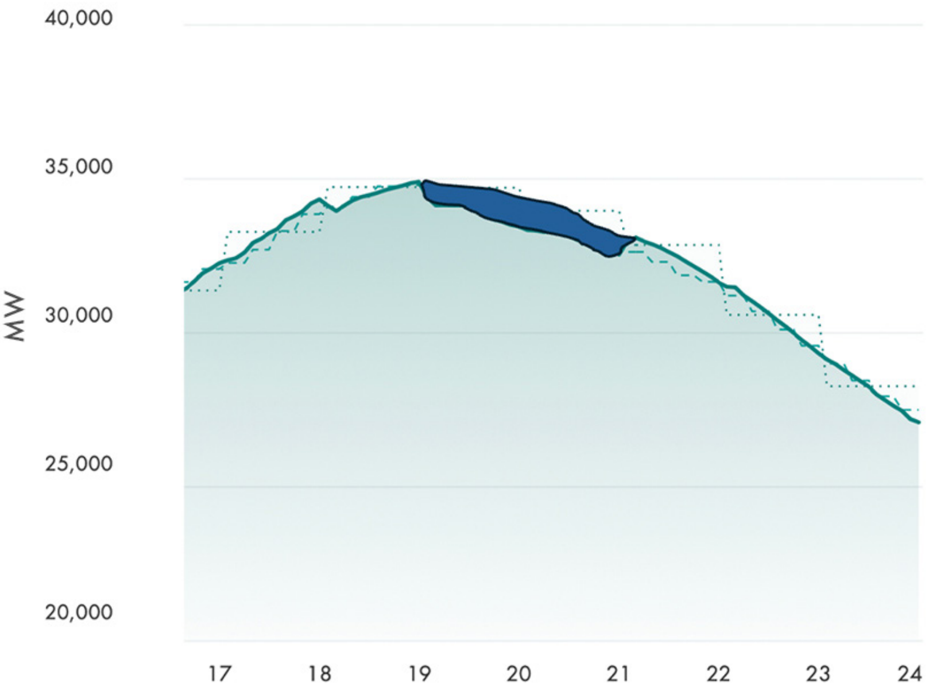
Bidirectional Relief

An Expanding Resource: Pacific Gas and Electric (PG&E) *noted in its press release* that the batteries were enrolled in California's Emergency Load Reduction Program (ELRP) — which calls for 20 hours of dispatch annually — and the Demand Side Grid Support (DSGS) initiative — which requires at least one event per month. "If no real emergencies happen," the utility said, "test events like this one will continue to make sure everything works as expected."

California leads the nation with 686 MW of commercial and 1,829 MW of residential distributed batteries as of April, at more than 25,000 sites. That population is growing quickly in California and elsewhere, often in tandem with solar installations. SunRun reported that in Q2 of 2025, 70% of its customers also bought batteries (up from 54% during Q2 of 2024). The company is dispatching its battery fleet across the U.S., providing 340 MW of batteries to grids in California, Massachusetts, New York and Puerto Rico during a single June day.

Tesla operates in California but also is *co-ordinating battery-based VPPs in Texas*, where it gained approval in 2023 to participate in ERCOT's Aggregated Distributed Energy Resource (ADER) pilot project serving Houston and Dallas. It coordinates with VPP platform company Energy Hub to provide services to Massachusetts, Connecticut and Rhode Island while overseeing a separate aggregated offering in Puerto Rico.

Utilities Increasingly Embrace VPPs: Across the U.S., more utilities are deploying batteries to push the boundaries at the grid edge, offering reliability to customers while creating capacity management, renewables integration and grid balancing services.



Bidirectional relief | *CAISO*

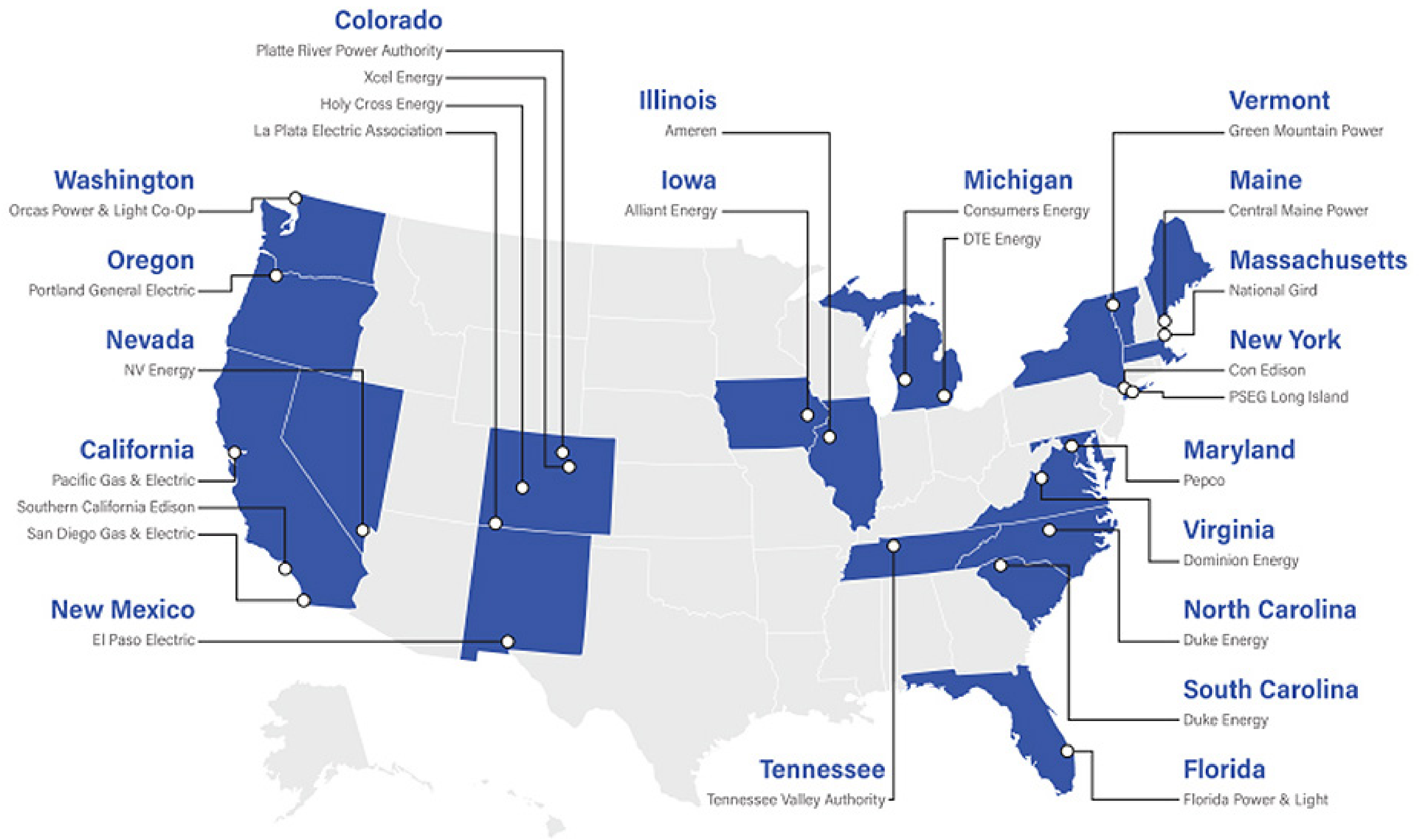
> ## Why This Matters
> Keeping the lights on in the decades to come may in part depend on how quickly these virtual power plant resources become a normal part of our electricity landscape.

To cite some examples, *Utah's Rocky Mountain Power launched* a pilot six years ago, connecting 12.6 MW of batteries deployed by solar and storage company Sonnen to its control room. Following that success, it *received approval* from the state's regulators in 2020 for a tariff to retrofit batteries to existing distributed solar installations. This year, it went further, *signing an agreement* with Torus for up to 70 MW of distributed storage systems using batteries and flywheels.

Vermont's Green Mountain Power (GMP) continues to expand its battery program started in 2016. By 2023, *it had 22 MW* of distributed batteries that had delivered *10,000 hours of backup power* to customers during the previous winter. Under GMP's program, customers can lease the batteries or own them and receive rebates for participation in the utility's Bring Your Own Device aggregation program, which pays participants up to $10,500. As of 2025, *5,000 customers* are engaged in the program, with batteries both providing backup power and helping GMP reduce exposure to wholesale power costs by an estimated $3 million this year.

Minnesota's Xcel Energy is adopting a unique approach, installing solar arrays and batteries as part of a *distributed capacity program* including up to 1,000 MW of DERs in a utility-owned and rate-based VPP. The plan won regulatory approval in February, with a detailed proposal expected this October.

VPPs Go Well Beyond Batteries: While batteries form the backbone of many VPPs, other technologies often are involved. Grid-interactive water heaters frequently participate in load-shifting and peak management programs and have provided frequency regulation services.



Batteries on wheels help school districts access grid revenues | *Electric School Bus Initiative*

Water Heaters can Shift Load AND Help Manage Frequency

Air conditioners and smart thermostats also are part of the mix, with VPP programs expanding in recent years as technology improves. Late in 2024, for example, NRG *teamed up* with Renew Home and Google Cloud in Texas and aims to distribute, connect and orchestrate hundreds of thousands of thermostats into a 1,000-MW AI-powered VPP by 2035.

Electric Vehicles: Class of Their Own: EVs represent a potentially massive and growing resource. Sophisticated charging architectures and improved batteries now can accept charges of 300 kW or more (and trucks can exceed 1 MW). It will become increasingly important to manage when they are charged. The cost of not doing so *can run quickly* into the billions, as distribution grids come under significant related stress.

EV batteries are big, especially when compared to residential storage. The bidirectional capable battery in the smaller of the *Ford 150 Lightning* models is 98 kWh, more than seven times larger than a 13.5-kWh *Tesla Powerwall battery*, while the large Ford version boasts 130 kWh. For its part, a typical "Type C" school bus battery sits around *200 to 300+ kWh*.

Multiple auto manufacturers now include vehicle-to-grid (V2G) capabilities in charging and battery architectures to take advantage of the potential grid revenue streams. When BlueBird upgraded the warranty on its Type C bus battery to 360 MWh of lifetime throughput, it specifically *cited the ability* of EV fleet operators "to sell excess energy stored in school bus batteries back to electric power companies at a profit."

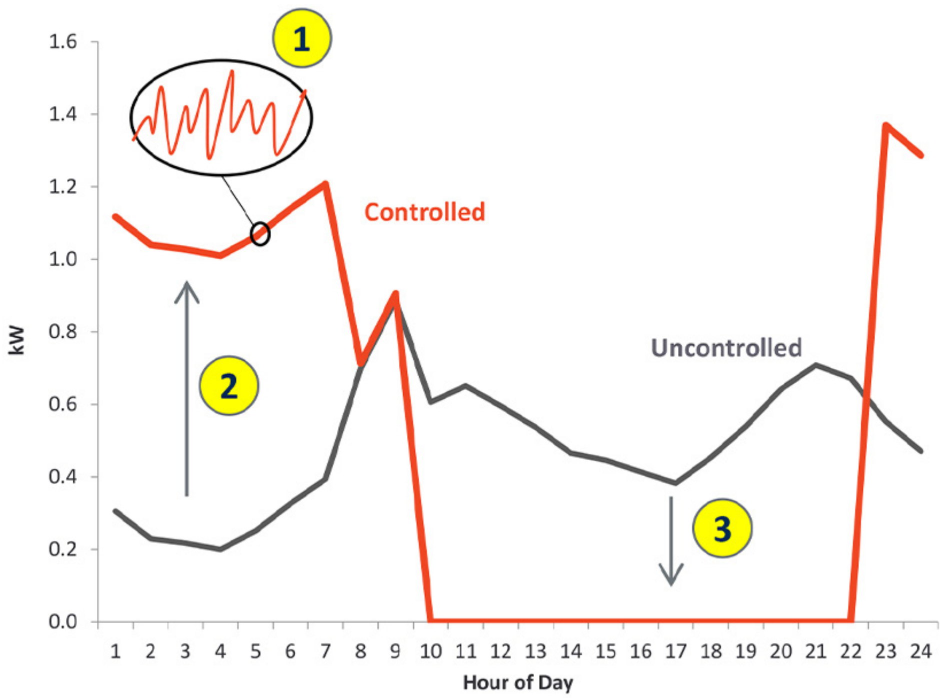
While only a handful of drivers participate in bidirectional charging pilots, vendors and utilities are addressing the technical and behavioral challenges holding this potential back. School Bus V2G programs are having the most initial success, with *26 utilities in 19 states* having rolled out programs to date.

Last year, leasing company Zum *announced a program* to deliver 2,100 MWh of energy annually from 74 electric buses (leased to the Oakland Public School District) back to PG&E. This month, *PG&E teamed up* with Fremont Unified School District (FUSD) and The Mobility House to manage 14 bidirectional-capable school buses.

The Outlook: Fast, Flexible, and Expanding: As electricity demand grows, and generation has trouble keeping pace, VPPs offer a nimble alternative. A recent *Department of Energy report* (now unavailable on DOE's website) found that VPPs can be built over just six to 12 months, far faster, and at a lower cost than batteries or gas-fired generators. The report also suggested that VPPs eventually could grow to represent as much as 10 to 20% of U.S. peak demand.

Getting Needed Capacity Faster

The DOE report noted that VPPs still face some critical obstacles. Areas to be addressed include simplification of asset enrollment, increased standardization of operations and improved integration of these aggregated resources into both utility and wholesale markets.



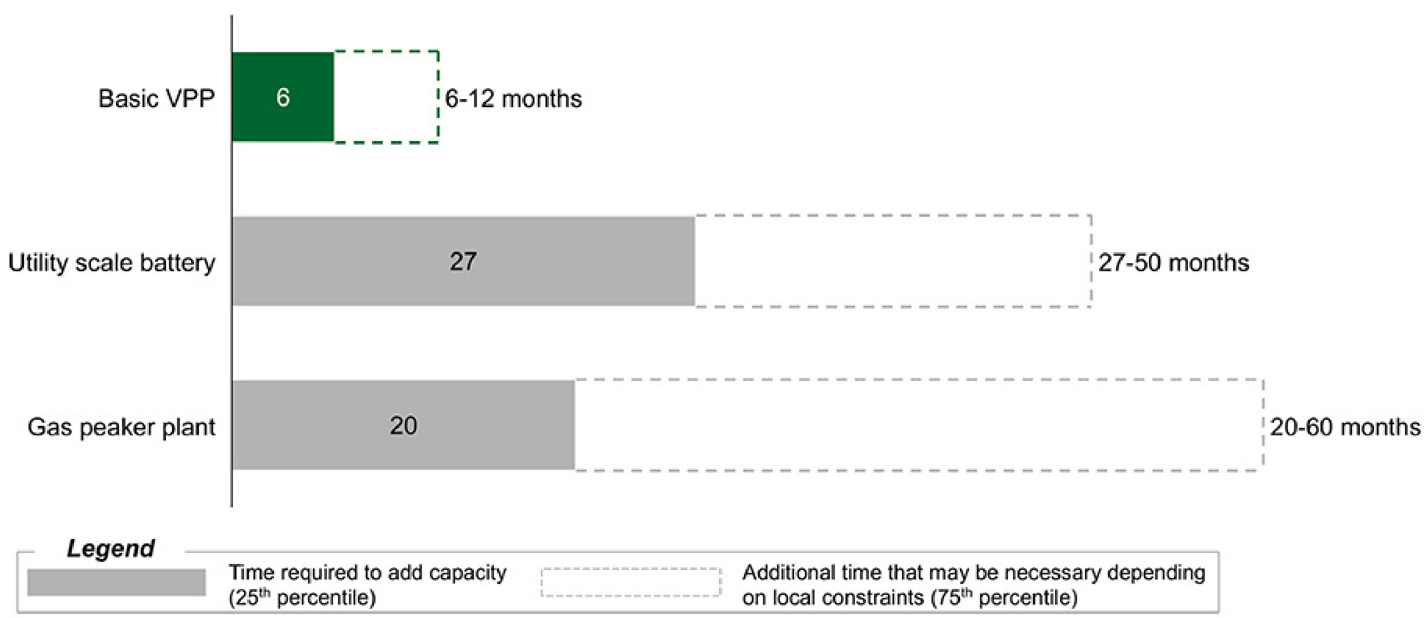
Water heaters can shift load, AND help manage frequency | *Brattle Group*

The VPP world is fragmented and generally characterized by pilots and evolving initiatives. There is a long way to go before we move from today's typical demand response programs — with limited numbers of dispatch events — to a more seamless and price-responsive future, in which on-site assets simply react predictably to price signals or specific grid conditions.

Nonetheless, solutions providers are making true progress, and the achievements are considerable. To take some other examples: *EnergyHub reports* 2,000 MW of flexible load, made up of 1.7 million DERs. Demand response provider *CPower* manages 6,700 MW of dispatchable load across 23,000 customer sites, while its competitor *Voltus stated recently* that it is dispatching distributed assets every single day.

The challenge of resource adequacy will become increasingly critical as supply resources struggle to keep up with rapidly growing demand. However, as artificial intelligence and grid software improve, VPPs will become an even more helpful tool for improving economic efficiency, reliability and resilience. Keeping the lights on in the decades to come may in part depend on how quickly these virtual power plant resources become a normal part of our electricity landscape. ■

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



Timeline to add 20 MW of dispatchable peaking capacity, months | *DOE*

Chatterjee, Bush Expect Sharp Changes in Response to OBBBA

Policy Shifts Come as Demand and Prices are Rising

By John Cropley

Former FERC Chair Neil Chatterjee says implementation of the Inflation Reduction Act went too far in limiting fossil fuels and implementation of the One Big Beautiful Bill Act may limit renewables too strictly.

Both sides of the aisle need to recognize that a true all-of-the-above approach is needed in this time of growing power demand and potential inadequacy of generation, he said.

Chatterjee and former Texas Land Commissioner George P. Bush offered their thoughts on the impact of OBBBA on the energy sector during an *HData webinar* Aug. 21.

Bush, now a strategist in Texas, said the impacts of the bill are many and significant: "This is definitely going to be the consequential bill for Trump 2.0. It's people like Neil and I that make a living helping people interpret it."

Chatterjee said the present situation — rising power prices amid rising demand — is not a result of OBBBA's cuts to renewable energy subsidies, it is due to the Biden administration accelerating generation retirement prematurely.

"I think the risk going forward for the [Trump] administration and for congressional Republicans, I don't want to see them make the same mistake, quite frankly, that the Biden administration did," Chatterjee said. But it is starting to happen, he added: "The Trump administration, since passage of the OBBBA, has taken a number of steps via executive orders and agency actions to really hinder the deployment of clean energy resources."

Why This Matters

To win the AI race, meet rising demand and keep prices affordable, a true all-of-the-above mix of sources will be needed, Chatterjee said. Also needed: transmission expansion, grid-enhancing technologies, energy efficiency, demand response, virtual power plants and distributed energy resources.

President Trump signs the One Big Beautiful Bill Act into law in a July 4 ceremony at the White House. | *The White House*

Bush said the energy industry and its regulators need to rethink their operating model.

"My hope is that jurisdictions are going to cut red tape and allow for more behind-the-meter generation, allow the private sector — of course, in a very thoughtful way — to generate this power that can be used by large load users, namely in industries that we've talked about," he said.

"I think a lot of utilities and districts are going to become entrepreneurial and help underwrite these projects or just administer the underwriting of the project."

America cannot win the AI race, meet rising demand and keep prices affordable without a mix of natural gas, wind, solar, geothermal and nuclear, Chatterjee said. And those new gigawatts of power need to be optimized with transmission expansion, grid-enhancing technologies, energy efficiency, demand response, virtual power plants and distributed energy resources.

"It all needs to be on the table, and I'm optimistic that we can have conversations at both the federal level and the state level, and kind of come together to figure out what the path forward is."

Bush observed: "I do not envy people that are now in this business, the regulator, and making sure you're keeping power prices low enough for your constituents and helping underwrite the process for these massive asset projects."

States and regions have long wrestled with market regulation, Chatterjee said, whether they have traditional vertically integrated utilities or competitive wholesale power markets. Neither model is perfect, he said, and both have challenges.

These new challenges will lead to the design of more innovative mechanisms, he predicted.

"Whenever you have big pieces of legislation, whether it be the IRA or the OBBBA at the federal level, that tends to prompt reactions at the state level," Chatterjee said. "And so I fully anticipate in the coming years to see states who benefited from OBBBA or those who had their concerns with it, potentially modify policies within their own parameters to account for the shifting policy, legislative and market energy landscape."

Texas has the second-largest energy storage capacity of any state and, not coincidentally, the second-largest solar capacity and the largest wind capacity.

Bush predicted storage capacity will grow: "I really do think commercial battery storage — a lot of folks in renewables will pivot to that to store the renewable capacity that they've already built."

Bush said OBBBA's impact on the industry will be wide-ranging, particularly in a state like Texas, where a massive amount of capital has been expended on renewables.

"We got a lot of calls in our practice with respect to, 'How do we preserve these tax credits? We made these assumptions, we raised capital from outside investors, and what does that mean?' And so there will be kind of an expedited time frame to work with, but the private sector, I think, is going to stand up to this challenge."

Chatterjee had a similar take, saying the picture still is evolving a week after the IRS guidance on wind and solar tax credits was issued, and some businesses will be able to evolve with it.

"I think maybe there were some bad actors that were created out of the policy that came from the Inflation Reduction Act," he said. "Folks chased the subsidies and got into the field without necessarily having a coherent business model, a lot of those bad actors are probably going to fail in light of the policy changes. But I think the companies, particularly on the clean tech side, that come through this, will come through stronger than ever, and will diversify their business model away from subsidies to provide that power and reliability." ■

U.S. Could Gain 33 GW of Solar, 18 GW of Storage in 2025

EIA Reports Record-high Capacity Additions Planned

By John Cropley

The United States is on track for a record increase in power generation capacity in 2025, the U.S. Energy Information Administration reports.

The EIA said Aug. 20 that developers reported plans for *64 GW of new generation* this year, which would surpass the current record — 58 GW — set in 2002.

A key difference is that the 2002 total included 57 GW of natural gas-fired generation, while only 4.7 GW of gas generation is expected to come online in 2025.

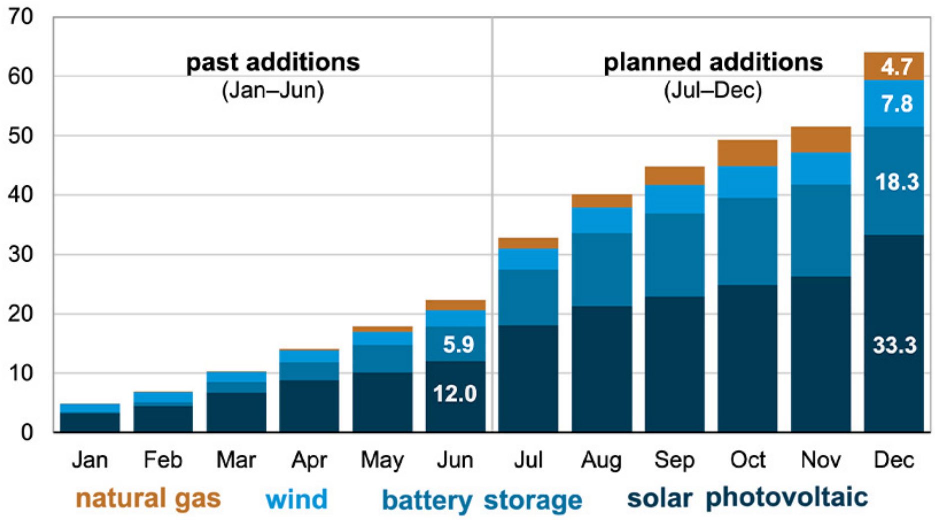
Instead, the majority of new capacity this year will involve the sun: EIA predicts 33.3 GW of new photovoltaic solar generation.

Solar's benefits to the planet notwithstanding, its capacity factor is much lower than gas-fired generation's. But EIA reports 18.3 GW of battery storage capacity is expected to be commissioned in 2025, which will help smooth out the peaks and dips in solar generation. That would be a whopping 76% increase over the 10.4 GW of storage installed in 2024.

Storage is not generation, but it is classified as a secondary source of electricity, so EIA includes it in its roundups of generation statistics.

Rounding out the 2025 picture, EIA predicts 7.8 GW of wind generation being added to the grid this year.

Cumulative utility-scale electric generating capacity additions (2025)
gigawatts



Solar energy dominated U.S. capacity additions completed in the first half of 2025 and is expected to dominate the second half. | *EIA*

EIA's solar and storage projections have changed in the six months since President Donald Trump returned to office, but not to a degree that would reflect his strongly anti-renewable, pro-fossil-fuel agenda.

In its *January 2025 Short-Term Energy Outlook*, EIA said it expects 26 GW of new solar capacity in 2025 — substantially less than the 33.3 GW that developers now say they expect to complete this year.

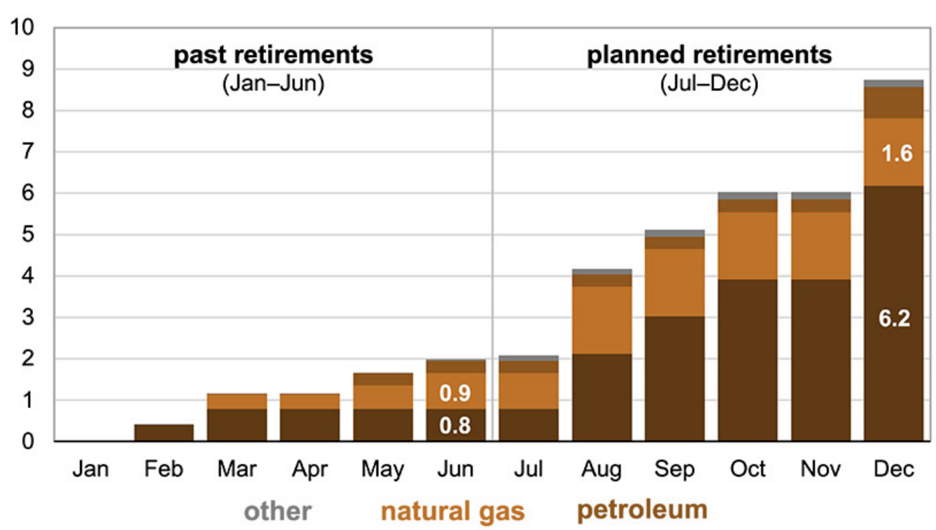
And in March 2025, *EIA said the energy sector expected* to add 19.6 GW of storage this year, a bit more than the 18.3 GW now expected.

EIA's Aug. 20 update also touched on the other side of the coin: retirement of generation.

The industry expects to retire 8.7 GW of capacity this year, including 6.2 GW of coal and 1.6 GW of gas generation. But it had retired only 2 GW by the end of June and had canceled or delayed retirement of 3.6 GW of capacity.

EIA *reported in February 2025* that electricity generators planned to retire 12.3 GW of capacity this year, 65% more than in 2024. The great majority of this was to be coal plants and simple-cycle natural gas turbines. ■

Cumulative utility-scale electric generating capacity retirements (2025)
gigawatts



A significant amount of coal generation retirements are expected this year, despite the Trump administration's efforts to slow the trend. | *EIA*

Why This Matters

The data suggest that the impending U.S. turn away from renewable energy development is not yet showing results.

USEA Panel: Power Sector Moving Slower than Big Tech

Speakers Say Regulators, Industry Need to Step up to Meet Data Center Demand

By John Cropley

A group of industry insiders looking at ways to meet data centers' electricity demand found a common thread within their varied opinions: The power sector and its regulators need to be a lot nimbler.

The United States Energy Association's monthly *virtual press briefing Aug. 20* focused on ways Big Tech is reshaping the electric utility sector or even upending it, with the potential for major data centers to add their own power generation.

Speakers drawn from the power and technology sectors fielded questions from a panel of journalists on what is at once a potentially lucrative and disruptive scenario facing the electric power industry.

Among the themes:

How much additional generation needs to be built to serve data center loads — or is this more of transmission issue?

It is both, said Tom Falcone, president of the Large Public Power Council. There also are the secondary issues of supply chain and workforce adequacy, permitting and retirement of existing generation.

After two decades of flat demand, unprecedented growth is projected, said Clinton Vince, head of Dentons' U.S. Energy Practice. Further, the 24/7 nature of this demand also is unprecedented, he said.

Jeff Weiss, executive chairman of Distributed Sun and truCurrent, said the 20th-century grid that exists is not up to the task: "Electricity scarcity is upon us, and this is the new world for industrials, for data centers, for consumers, where electricity is not abundant and we need to manage sources of power." Fortunately, he added, battery storage is bridging some of the gap.

Speed is the overriding issue, said Derek Bentley, a partner at Solomon Partners, and trends are not favorable. GE Vernova needs a five-year lead time to equip a new combined-cycle gas plant that then takes a couple more years to build, while renewables are intermittent and the target of policy changes. "But with the data centers, you can generally build a data center in 12 to 18 months."

A network of electrical cables feeds power into one of Google's data centers in Midlothian, Texas. | *Google*

Notable Quote

"Everything we do takes 10 years or more. We need to figure out how to do everything in two years."

— Jeff Weiss, executive chairman of Distributed Sun and truCurrent

Karen Ornelas, director of large load program management at Pacific Gas & Electric, said PG&E has started a cluster process for new load requests, which has reduced the duration and cost of engineering studies.

Tom Wilson, principal technical executive at EPRI, said demand flexibility will help ease the crunch that is developing. EPRI's DCFlex initiative has involved more than 50 entities in multiple sectors to demonstrate ways data centers can moderate that 24/7 demand.

Balancing Act

How do you balance the sharp increase in new load with the imperatives of affordability and reliability? How do you balance the needs of new data centers with those of existing residential and industrial customers?

There is a lot of uncertainty, Falcone said, "and so what you see is a lot of reforms happening at the state level and with individual utilities to better understand and also get some financial commitments that are longer-term."

Weiss said the nation is trying to grow in the 21st century using a 20th-century utility system, a prescription for failure, and "the regulatory construct puts a lot of lethargy" in moving forward from that. "Everything we do takes 10 years or more. We need to figure out how to do everything in two years … and it's critical to our economy that we do that."

That's why so many behind-the-meter

partnerships are being formed, Bentley said. “Unfortunately, there isn’t just a silver bullet solution right now, and so it does require a lot of things, all coming together, a lot of constituents working together to solve the problem.”

Bud Albright, senior energy adviser at the National AI Association, reminded listeners that policy does not exist in a vacuum: “We need to get in front of the public at a grassroots level, to educate them if you will, to the benefits of bringing new power online wherever it is. As we all know, there’s huge pushback when data centers come in, the public saying, ‘Don’t take our power, don’t take our power. It’s going to drive our costs up.’”

Trump Card

President Donald Trump is pushing through significant policy changes in the energy sector. What is he getting right, and what does he need to improve?

Vince praised Trump’s moves on nuclear power, battery storage and delayed fossil retirements but added: “I think the discontinuation of credits and other limitations on the solar and wind industry is unfortunate.”

The president has correctly framed the issue, which is the need for a review of existing processes and significant changes, Falcone said.

Redland Energy Group Principal John Howes said: “I think the president has done some very good things. For example, he’s done a lot to eliminate some of the bias against fossil fuels which existed in the last administration.” More attention must be paid to permitting reform, he said, as well as to the foundational components of the system, such as transformers, and to its human component, through workforce development.

Disruptive Presence

If hyperscalers can move more nimbly and set up behind-the-meter generation more quickly, do they become a threat to utilities?

If someone wants to cut the cord and truly be off the grid, they can order the equipment and install it, Falcone said, and maybe reach the finish line more quickly. But otherwise, they need to operate within the same construct as everyone else attached to the grid.

Vince said some utilities are working well with Big Tech and finding solutions. But many are not, and capitalized hyperscalers are proceeding without them, taking an entrepreneurial approach. “The slower utilities, I think, will be disadvantaged tremendously,” he said.

It need not be mutually exclusive, Bentley said — a data center that builds its own generation may not remain permanently or entirely behind the meter or off the grid. “We’re seeing a lot of unique and tailored solutions … a lot of innovative structures.”

Wilson said flexibility and adaptability such as demand response or onsite storage will help: “Agility is not just being able to buy equipment faster, but it’s being able to be an asset to the grid, as opposed to a passive load.” ■

States' Interregional Transmission Efforts Examined

ACORE Panel Looks at Obstacles Facing Long-held Goal

By John Cropley

Advocates for interregional transmission should focus more on allocation of benefits than on allocation of costs, a researcher said during an ACORE webinar.

This — along with identifying the constituency for a project and the regulatory gaps that would thwart it — would help advance the longstanding goal of building more wires to move electricity across state lines and RTO/ISO boundaries, said Abe Silverman, who is facilitating a nine-state collaborative to advance interregional transmission.

The American Council on Renewable Energy hosted "*Powering Progress: States Leading on Transmission Collaboration*" on Aug. 19 to look at the outcome of past multistate collaborations and at the ongoing efforts toward further collaboration.

ACORE's Kevin O'Rourke was joined by Silverman, an assistant research scholar with the Ralph O'Connor Sustainable Energy Institute at Johns Hopkins University; Anya Poplavska, senior policy advocate at the Acadia Center; and Beth Soholt, executive director of the Clean Grid Alliance.

Soholt spoke of CapX2020, the successful $2.1 billion effort by 11 utilities to build nearly 800 miles of 345- and 230-kV transmission lines across Minnesota and into three neighboring states.

Why This Matters

Singing the virtues of interregional transmission is easier than building it.

There was a long process of lining up internal and external support, financing, regulatory approval and community acceptance, she said, as well as the challenge of shaping a disparate group of cooperatives, municipal utilities and investor-owned utilities into a coalition of the willing with a consensus on a common goal.

The CapX2020 project of the 2000s and 2010s was a model of cooperative regional planning by 11 utilities in four states that resulted in 800 miles of new high-power transmission at a cost of $2.1 billion. | *Grid North Partners*

"It's a lot easier to kill a project, it's a lot more difficult to make it happen," Soholt said. "And this group did come together and make it happen."

Poplavska spoke about the Northeast Grid Planning Forum, convened by the Acadia Center and Nergica to lay the groundwork for collaboration to meet what is projected to be a 100% increase in power demand over the next quarter century — and to loop in neighboring parts of Canada, which has a deep and longstanding infrastructure connection with the U.S. Northeast. (See *New Initiative Focuses on Interregional Tx Coordination in the Northeast*.)

There is only piecemeal and fragmented decision-making now, she said. "And [the forum is] really born of the synergies between Canada and the Northeastern states. The whole point of it is to really create a framework across these different regions that facilitates planning, coordination and decision making."

Accentuate the Benefits

Poplavska identified three steps in the process: identification of needs; design and selection of projects; and, most difficult of all, allocation of costs.

"How are costs going to be borne across different regions?" she said. "I don't think it's a stretch to say that this is a huge limitation and reason that interregional projects just don't get pursued as much."

A potential best practice, Poplavska added, would be to move beyond a strict 1-1 benefit-cost ratio on cost allocation and allow states to voluntarily cover additional costs that contribute to meeting their policy goals.

"Cost allocation is a bit of a red herring," Silverman said. "Because what we really need to talk about is benefits allocation. Because all these projects have such enormous net benefits that if we really get hung up on how we're allocating the costs without taking into consideration the benefits, we end up having sort of a circular conversation that we very rarely get anywhere."

It is a very different discussion, he added, to go to the governors of three states and say "We have a billion dollars of benefits we have to allocate between the states" rather than "We have $500 million of costs that we need to allocate."

Silverman is facilitator of the Northeast States Collaborative on Interregional Transmission — an effort that spans nine states from Maine to Maryland served by three grid operators. (See *State Officials in the Northeast Discuss Interregional Transmission Plan*.) The states entered a memorandum of understanding in 2024 to accelerate the siting and permitting of regional and interregional transmission.

All signs point to the benefits of regionalization, Silverman said, and it serves the competing visions of decarbonization and fossil fuel-based energy dominance.

"There's probably 20 high-quality studies all showing enormous consumer benefits if we get interregional transmission right," he said. "And that's everything from faster deployment of data centers and clean energy and economic development in our states. It's also often lowering costs for consumers, and it's certainly improving reliability."

Silverman added: "But what we sort of have encountered is that there is a regulatory gap between the benefits and the people who see the benefits and the people doing the grid planning."

He said the value of the collaborative he is working with and the forum Poplavska is working with is that they create the constituency that can advocate for those gaps to be closed, and allow these types of projects to move forward.

"If all we needed was another study talking about how beneficial interregional transmission was, we'll just keep writing those studies forever," Silverman said. ■

EDAM Implementation Team Reveals New Intertie Scheduling Approach

Working Group Also Touches on Congestion Revenue Rights Treatment

By David Krause

CAISO staff on Aug. 21 showed how the grid operator plans to implement certain parts of its Extended Day-Ahead Market (EDAM) next year, with stakeholders asking for more time to comment on what they said crossed into potential policy revisions.

CAISO began the workshop by discussing changes to intertie scheduling processes. In the ISO's current day-ahead market, intertie schedules occur at an intertie scheduling point, George Angelidis, CAISO executive principal of power systems and market technology, said at the workshop.

But under EDAM, intertie schedules will be taken at a Generation Aggregation Point (GAP) in the corresponding source or sink balancing authority area (BAA), Angelidis said. This change will increase the accuracy of power flow on the grid and improve power flow congestion, and more closely aligns with actual flow by reducing phantom congestion, Angelidis said.

CAISO broke down the GAPs into three types: a Default Generation Aggregation Point (DGAP), a Custom Generation Aggregation Point (CGAP) and a Generic Generation Aggregation Point (GGAP). Each type is used to determine intertie participation categories.

Under EDAM, there will be "specific GAPs for balancing authority areas that are the source or the sink of the energy for the import or the export," Angelidis said.

"We want to have more accuracy in the power flow calculations and market solutions," Angelidis said. "In the current market, at the intertie scheduling point … there is no resource actually at that location, so modeling energy of the import or the export at that location is inaccurate."

CAISO is therefore moving the intertie scheduling location under EDAM to "somewhere where it is more reasonably representative of the energy being generated or consumed," Angelidis said.

"Of course, accurate market solutions for power flow translate to accurate congestion management and also accurate locational marginal prices," Angelidis said.

Some stakeholders at the workshop said they were concerned that some of the implementation processes presented by CAISO were in fact policy-related issues, which should be discussed further in other workshops with comment periods.

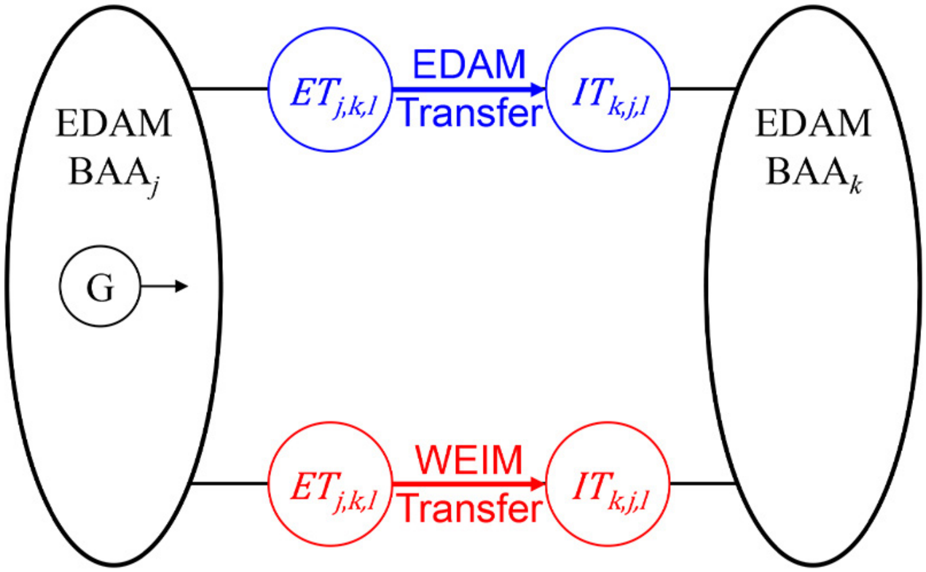
"We need some form of formal comment period," said Dan Williams, principal adviser with The Energy Authority. "Being someone who has been involved with this initiative since 2018, I was under the understanding from the EDAM design and discussions during that time that EDAM implementation was primarily about the CAISO BA and its interaction with the EDAM BAs."

Williams said he thought CAISO's interties, other bilateral intermarket activity in the West and the EIM were "not going to be fundamentally impacted in the way that it is to me being described here."

"There is, for me, a large impact here to the market in general and contracting that is a lot for folks to absorb in one workshop," Williams added.

CAISO also discussed how it plans to implement congestion revenue rights and settlements under EDAM. CAISO is looking to phase in its implementation of its CRR model, which could improve the accuracy of the model, said James Lynn, CAISO principal.

When EDAM begins, CRRs will not be paid based on constraints where the CAISO BAA does not receive congestion revenue from integrated forward market flow on that constraint, Lynn said. ■



Intertie participation modeled from resources in an EDAM BAA | *CAISO*

Why This Matters

CAISO plans to open the Extended Day-Ahead Market in 2026, with many of the new processes needing implementation plans before then.

WRAP Day-Ahead Market Task Force Moves Forward on Concept Paper

Document to Describe Program's Principles Under West's 2-market Landscape

By Henrik Nilsson

The Western Resource Adequacy Program (WRAP) Day-Ahead Market (DAM) Task Force is finalizing a concept paper that outlines proposed principles for the program under the West's new market landscape.

The task force held its fifth meeting Aug. 21 to continue discussions on how to update or optimize WRAP's Operations Program to make it compatible with the soon-to-be-launched SPP Markets+ and CAISO Extended Day-Ahead Market (EDAM). WRAP was designed before the two markets completed their designs. (See *WRAP Task Force Explores Optimization Under Day-ahead Markets*.)

The task force has until Sept. 10 to present the concept paper to WRAP's Resource Adequacy Participants Committee (RAPC) to provide an update on the topics and proposals the group is considering.

After submittal, the RAPC can provide advisory endorsement or recommendations on how the group should proceed. The RAPC will provide formal input after a final proposal has been presented, according to Michael O'Brien, WPP's senior policy engagement manager for the WRAP.

"Even though we have participants and task force members committed to different markets, they are collaborating on drafting mutually beneficial changes to the operations program, so this task force is a big opportunity to make improvements that everyone can agree on," O'Brien said in an email to *RTO Insider*.

"We seem to have consensus that we're headed in the right direction," O'Brien added. "We've identified the right topics — like holdback, energy deployment, settlements and energy delivery failures, processes that require fine-tuning to deliver the best results in the day-ahead market environment. We are having robust discussions. The concept paper is a work in progress, and we're getting valuable input on both direction and technical details."

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

Western Spirit transmission line | *Pattern Energy*

Why This Matters

The task force is busy trying to adapt WRAP to the multimarket reality emerging in the West.

Much of the discussion on Aug. 21 concerned which entity should be responsible for energy delivery failure charges. The group agreed that surplus participants will retain responsibility for energy delivery failures within and between market-based operational subregions.

Rebecca Sexton, director of reliability programs at WPP, said during the meeting that WRAP only assigns the obligation and provides the penalty incentive to deliver. The participants will figure out how to meet their obligations through their respective markets.

"We have really tried to be very careful about drawing the line … it's the obligation of the participant that we put the whole [responsibility] back on, but however it is that you get that energy there, that's kind of out of scope of WRAP," Sexton said.

WRAP's binding phase 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 to avoid penalties. The binding phase is now expected to start in summer 2027. (See *WRAP Members Vote to Delay 'Binding' Phase to Summer 2027*.)

A final proposal from the task force could take several months. The proposal must also undergo a review and governance process with implementation slated for 2026, according to O'Brien. ■

Budget Cuts Threaten Calif. VPP Program

Brattle Study Finds Potential for $206M in Savings

By Elaine Goodman

Clean energy advocates are urging California lawmakers to restore funding to a fast-growing distributed energy program that can serve as a peaker plant alternative and showed its ability to support the grid during a test run.

Funding for the Demand Side Grid Support (DSGS) program is expected to run out this year and an estimated $75 million is needed to keep it going in 2026, representatives of more than 30 clean energy groups and companies said in a letter to state lawmakers.

The letter also calls for $50 million for the Distributed Electricity Backup Assets (DEBA) program, which incentivizes the construction of cleaner and more efficient distributed energy assets to be on-call for emergencies. DSGS and DEBA are California Energy Commission programs.

"At a time when affordability and reliability are under such strain, cutting these programs would take away proven cost-saving solutions just as they are most needed," the *letter* stated.

The Brattle Group recently completed an *analysis* of DSGS, focusing on the program's "Option 3," in which battery owners agree to make their stored energy available to the grid during energy emergency alerts or when day-ahead prices go over $200/MWh. Participants sign up through DSGS providers, which include companies such as solar-and-storage providers Sunrun and Tesla Energy.

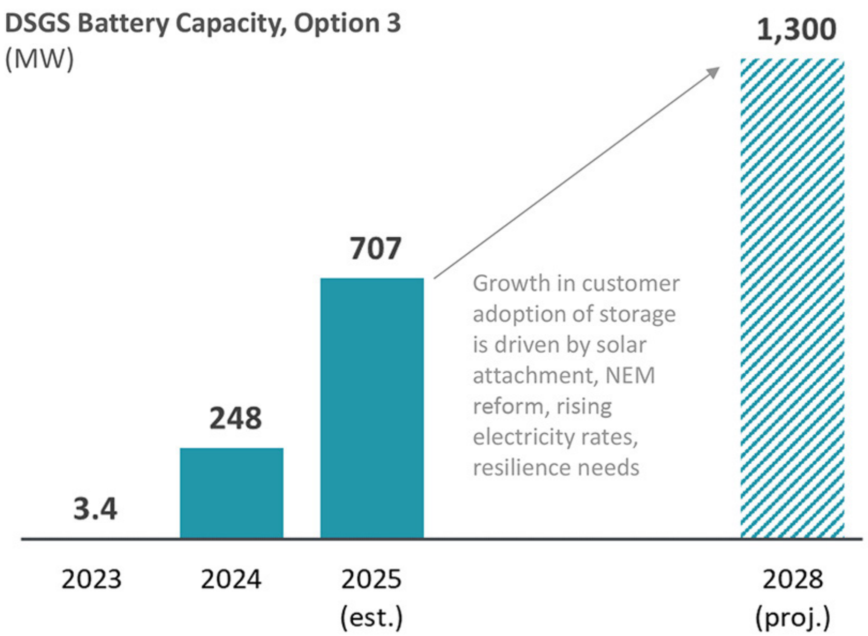
Participants are compensated based on the power they share with the grid.

"It's not a subsidy. It's not a giveaway or anything like that," Edson Perez, a senior principal at Advanced Energy United, told *RTO Insider*. Perez is one of the authors of the letter to lawmakers.

The Brattle study, which was prepared for Sunrun and Tesla Energy, estimates that DSGS Option 3 will reach 700 MW of nameplate battery capacity in 2025 and grow further to 1,300 MW by 2028.

Besides boosting the grid, DSGS can save money. Brattle projected program net cost savings of $28 million to $206 million from 2025 to 2028. The lower figure assumes the program provides capacity value and some energy cost savings. Program costs are mainly the payments to participating battery owners.

The higher savings scenario assumes California is paying more than $200/kW-year for emergency resources and that tariffs and supply chain issues are increasing capacity costs. In that case, DSGS would be "a significantly lower-cost alternative," Brattle said.



A Brattle Group study projects that battery capacity in California's DSGS program will grow to 1,300 MW in 2028. | *Brattle Group*

Why This Matters

As more residents install batteries, virtual power plants created through programs such as DSGS may be a lower-cost option for delivering reliable, utility-scale capacity.

The Brattle study also assessed a virtual power plant (VPP) test event July 29 involving about 100,000 residential batteries. The batteries were primarily enrolled in the DSGS program, and the two main aggregators in the test were Sunrun and Tesla Energy.

The batteries provided an average of 535 MW of support to the CAISO grid during the 7-to-9 p.m. test period. (See *Home Batteries Provide 535 MW to CAISO Grid on VPP Test Day*.)

"Aggregating home generation and storage produces a reliable, flexible energy resource that dispatches at the same scale as multiple peak generation plants to help meet soaring electricity demand," Sunrun CEO Mary Powell said in a statement.

Although the governor's proposed budget in January included money for the DSGS program, that funding disappeared in later budget revisions. Perez said those who signed the letter to key legislators would leave it up to the lawmakers to decide how to fund DSGS.

And at least one state senator has indicated his support for doing so.

Sen. Josh Becker (D), chair of the Senate Energy, Utilities and Communications Committee, discussed the DSGS program during an Aug. 19 oversight hearing on grid reliability.

"That's a program that I think has had a great success," Becker said. "We had a great virtual power plant success recently. We need to make sure those are funded." ■

Black Hills-NorthWestern Merger Could Reshape Western Market Map

Too Soon to Determine Impact on Competition Between CAISO's EDAM and SPP's Markets+

By Robert Mullin

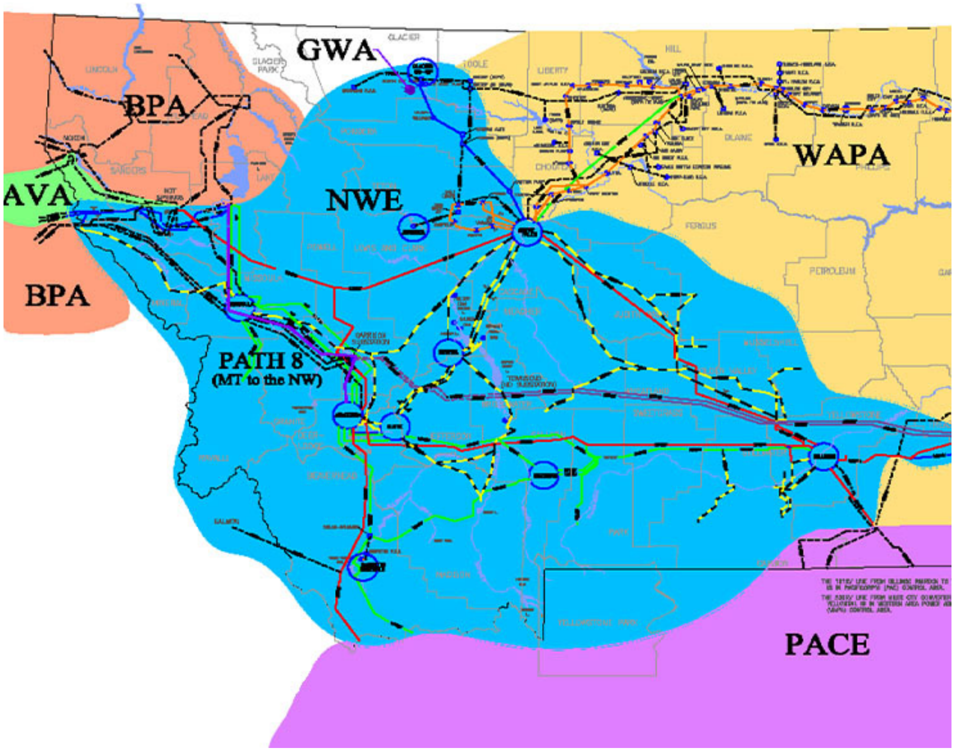
The proposed merger between Black Hills Corp. and NorthWestern Energy likely will reshape the map in the competition between CAISO's Extended Day-Ahead Market and SPP's Markets+ — but it's still too early to know where new boundaries will be drawn.

The two companies *announced* Aug. 19 that their respective boards of directors voted unanimously to approve an agreement to merge in an all-stock, tax-free merger that will incur no new debt.

The deal, which is expected to close in 12 to 15 months pending federal and state approvals, would "create a premier regional regulated electric and natural gas utility company with a *pro forma* market capitalization of approximately $7.8 billion and a combined enterprise value of $15.4 billion," according to a joint statement.

"The combined company will have greater scale and financial strength to consistently deliver for customers across our service territories and invest at the pace and scale that today's energy transformation demands," Black Hills CEO Linn Evans said in the statement. "Our vision is to be the energy partner of choice for our customers, communities and investors, and this merger will accelerate our ability to achieve this goal."

"Our merger with Black Hills will create a premier regional regulated utility company with a larger, more resilient platform consistent with mid-cap peers," NorthWestern CEO Brian Bird said. "Together, we will be better positioned to meet rising demand, accelerate investment in energy and grid infrastructure, and support customers and communities through a rapidly evolving energy landscape."



NorthWestern's balancing authority area (in blue) is bordered by BPA and Avista to the West, WAPA to the east, and PacifiCorp-East to the south. | *NorthWestern Energy*

Upon closing of the deal, shareholders of Rapid City, S.D.-based Black Hills will own 56% of the combined company, with the remaining 44% owned by shareholders of Butte, Mont.-based NorthWestern, leaving the Black Hills as the greater among equals in the merger.

The combined company — whose name has yet to be determined — will have its headquarters in Rapid City, and its board will include six representatives from Black Hills and five from NorthWestern. Bird will take the helm, with Evans retiring.

Black Hills serves 1.35 million electricity and natural gas customers across eight states: Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. The company's electricity operations are concentrated in the Western Interconnection and include its Black Hills Power and Cheyenne Light, Fuel and Power subsidiaries, which serve customers in southeastern Montana, western South Dakota and northeastern Wyoming, and its Black Hills Colorado subsidiary in the southern part of that state.

NorthWestern serves about 800,000 electricity and natural gas customers in Montana, South Dakota and Nebraska and operates a balancing authority area that covers a large portion of Montana.

In their joint statement, the two companies said the combined electric utility will serve about 700,000 customers and operate roughly 38,000 miles of transmission and distribution lines and approximately 2.9 GW of owned generation capacity consisting of a mix of thermal,

Why This Matters

The announced merger between Black Hills Corp. and NorthWestern Energy brings new uncertainty around whether the utilities involved will choose markets operated by CAISO or SPP.

hydro and wind. The combined natural gas utility will serve about 1.4 million customers and operate 59,000 miles of natural gas lines.

"Over time, this increased scale is expected to drive operating and cost efficiencies across the combined enterprise," the companies said.

'Just too Soon'

With such a sprawling territory, the combined electric utility operations of the two companies could shape the footprints of the two competing Western day-ahead markets in key ways, and the stakes could be especially high for Markets+.

NorthWestern, which has been participating in CAISO's Western Energy Imbalance Market (WEIM) since 2021, has not committed to either EDAM or Markets+ or expressed a leaning in either direction. According to sources close to the market decision process, the utility's decision still is very much in play.

Bordering NorthWestern's BAA to the west is the Bonneville Power Administration, which has committed to funding and participating in Markets+, although that decision is being contested in a suit filed in the 9th Circuit Court of Appeals. (See *BPA Sued in 9th Circuit over Day-ahead Market Decision*.)

To NorthWestern's southwest is Idaho Power, which has not committed to either market but is leaning heavily to EDAM, while to the south is the PacifiCorp-East BAA, which will become the first EDAM participant in spring 2026. To the east and southeast are Western Area Power Administration (WAPA) BAAs that plan to participate in SPP's RTO West expansion.

If NorthWestern were to commit to EDAM, the Northwest portion of the already-fractured Markets+ footprint would be further cut off from the islanded portion of that market represented by Public Service Company of Colorado's (PSCo) BAA. Alternatively, NorthWestern's participation in Markets+ would put connectivity between the Northwest and PSCo within closer reach.

But at first glance, the union between NorthWestern and Black Hills suggests the former scenario is more likely.

That's because in August 2024, Black Hills Power and Cheyenne Light — both currently located in WAPA's BAA — announced plans to exit SPP's real-time Western Energy Imbalance Service (WEIS) and join CAISO's WEIM in 2026. (See *CAISO's WEIM Plucks Black Hills Utilities from SPP's WEIS*.)

Among the reasons the utilities gave for the move was the fact that, with the expansion of both Markets+ and RTO West, SPP will disband the WEIS.

"The planned formation of the SPP RTO West required us to assess our future market path, as it did not appear that the WEIS market status quo would remain an option after RTO West is operational," Black Hills told ***RTO Insider*** at the time. "We have found imbalance market participation to be beneficial for our customers, and the opportunity for our utilities to participate in the WEIM allows us to continue to optimize our generation operations while maintaining our high reliability and creating long-term value for the customers we are privileged to serve."

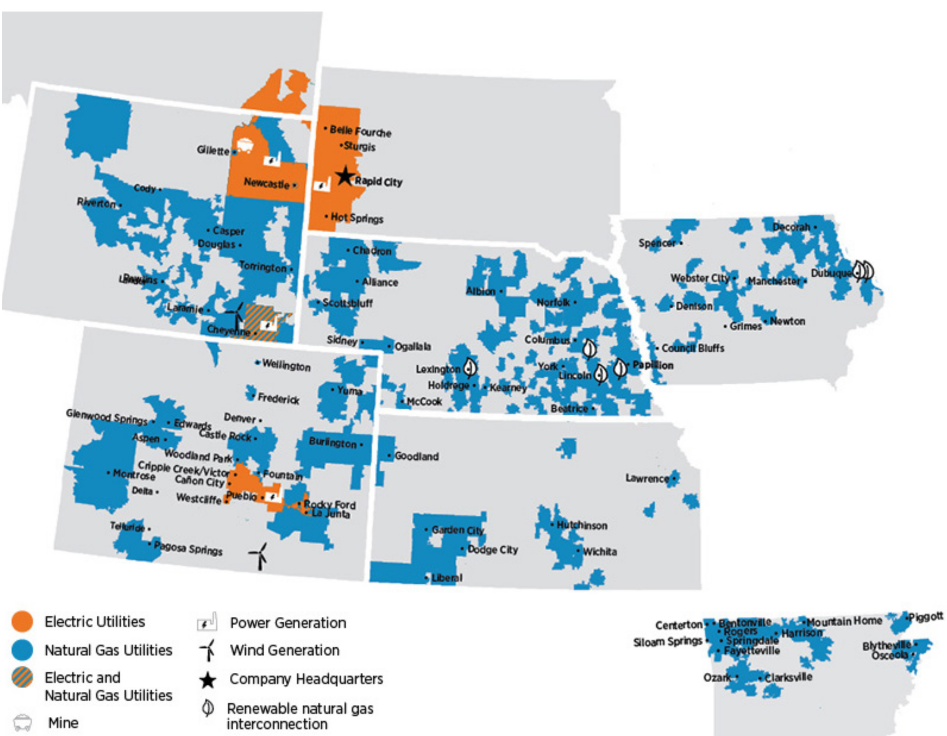
At the time, the move appeared to represent a geographically small but symbolically large victory for CAISO, since it would put the ISO's presence as far east as South Dakota. Now it could translate into a significantly greater advantage for CAISO as it seeks to court NorthWestern.

The WEIM implementation agreement signed between CAISO and Black Hills Energy stipulates that one of the company's utilities will be required to register a new BAA to facilitate participation in the market. The merger could enable the Black Hills utilities to instead join NorthWestern's BAA, but that would dictate that all three utilities participate in the same market, whether that be CAISO's WEIM or EDAM, or SPP's Markets+.

When asked how the merger could affect NorthWestern's decision to join a day-ahead market, and whether the two companies planned to consolidate BAAs in the West, utility spokesperson Jo Dee Black told *RTO Insider*: "NorthWestern and Black Hills will evaluate operational opportunities over the coming months and apply best practices where they are appropriate."

Black Hills spokesperson Theresa Donnelly offered a similar response to the same questions.

"With the newness of today's announcement, we're not able to respond to your questions," she said. "It's just too soon." ■



The territories of the two Black Hills Energy utilities joining the Western Energy Imbalance Market are represented on this map by the orange areas in Montana, Wyoming and South Dakota. | *Black Hills Energy*

Calif. Officials Probe Utilities on Safety Measures

SCE Asked to Show Humility in Response to L.A. Fires

By Henrik Nilsson

California officials asked Southern California Edison to show humility in its approach to the January wildfires in Los Angeles and probed Pacific Gas and Electric about its safety culture after the utility's 2019 bankruptcy during an inter-agency briefing hosted by the California Public Utilities Commission on Aug. 19.

SCE, PG&E, Bear Valley Electric Service, San Diego Gas & Electric, Pacific Power and Liberty Utilities briefed California officials on their wildfire safety procedures and mitigation work.

SCE independent board member Tim O'Toole opened the company's presentation by discussing the deadly L.A. fires that ravaged the city in January. He called them "an awful catastrophe," stating that SCE is focused on supporting impacted communities.

"Nonetheless, we remain very proud and confident in the progress we've made in all the areas we're going to review with you today," O'Toole added. "And I wouldn't want that pride and that confidence to be misunderstood or mischaracterized as insensitive or that there's some denial of reality."

O'Toole noted also that the cause of the fire is unknown, adding, "what we do have knowledge of, and are confident in, is that our unmatched hardening of our grid and the other mitigation measures we've implemented have created ever greater protection for our communities and our customers."

Among the steps SCE has taken are installing more than 6,610 miles of covered conductor and over 1,870 weather stations, 48 miles of undergrounding since 2021 and increased inspections in high fire-risk areas, according to SCE's presentation.

Why This Matters

The meeting came as the West faces increased wildfire risk and offered California agencies an opportunity to ask utilities about their mitigation work.

Caroline Thomas Jacobs, director of the Office of Energy Infrastructure Safety at the California Natural Resources Agency, acknowledged the cause of the L.A. fires is still unknown but sought more humility from SCE.

Addressing O'Toole, Thomas Jacobs said, "Your tone sounded defensive and justifying the progress that's made as opposed to acknowledging the humility of what an event like the January fires I would think would bring … to the board."

Thomas Jacobs added that "hopefully all of us are learning lessons from the January fires, including our organization, on how we look at the wildfire mitigation plans. We need to … bring a humility to those events and a level of curiosity and openness to create the opportunity for us to all move forward and learn from it."

O'Toole responded he is proud of his team but also wanted to acknowledge the pain the fires have caused.

"I just feel like I didn't articulate it well enough, but I certainly believe that what you said is the appropriate sentiment," O'Toole said.

Of the L.A. fires, the Eaton Fire and the Palisades Fire were the two most destructive. The L.A. County Fire Department and the California Department of Forestry and Fire Protection are still investigating the cause of the Eaton fire, but videos of the fire's early stages suggest a possible link to SCE's equipment, SCE representatives said in February. (See *SCE Probes Link Between Equipment and Eaton Fire*.)

On July 23, SCE announced a new wildfire recovery compensation program for victims of the Eaton Fire. The program is expected to operate through 2026, a company press release said.

'Totally Different Place'

Also participating in the Aug. 19 meeting were representatives from PG&E. Similar to SCE, the company has focused on undergrounding, installing more weather stations and cameras, and other grid hardening efforts to mitigate wildfire risk.

CPUC headquarters in San Francisco | © *RTO Insider*

The company received blame for a series of California wildfires starting in 2015. The fires included the 2018 Camp Fire, which leveled the town of Paradise, killed 84 people and drove PG&E to file for bankruptcy reorganization in January 2019.

Cheryl Campbell, chair of PG&E's Board of Directors and Safety and Nuclear Oversight Committee, said the company is in a "totally different place" compared with 2019.

Campbell noted that with the hiring of Patti Poppe as chief executive officer in 2021, PG&E has made "tremendous progress." She highlighted reductions in workforce fatalities and improvements in public safety power shutoffs.

PG&E has also reduced the unit cost for undergrounding. In 2019, the unit cost exceeded $4 million/mile. The average unit cost between 2023 and 2024 was $3.1 million, according to the utility's presentation.

Sumeet Singh, executive vice president of operations and chief operating officer at PG&E, said the company sees opportunities to further reduce undergrounding costs by, for example, improving construction methods and entering cost-effective contracts with third parties. There are also regulatory efforts to improve undergrounding, Singh noted. (See *Newsom Issues Order to Speed Undergrounding of Lines in Los Angeles*.)

"We absolutely see opportunities to continue to improve upon the $3.1 million a mile that we're currently averaging on the underground side, and our intent is to get to that glide path of $2.6 or below over the next several years," Singh said. ■

Managed EV Charging Could Save Utilities $30B, Study Finds

By Henrik Nilsson

Adapting charging of electrical vehicles to real-time grid conditions could save utilities up to $30 billion annually by 2035 and reduce peak energy demand, according to a new report by The Brattle Group and smart charging provider ev.energy.

The purported benefits would come from enabling managed-charging programs that encourage off-peak charging. This reduces strain on the grid and can help utilities avoid costly infrastructure upgrades, according to an Aug. 21 press release.

The report finds that managed charging can save up to $575 for each EV and 10% on home utility bills, with benefits potentially doubling with the inclusion of bidirectional charging, according to the release.

"As demand grows, and the world electrifies, there's a real risk that households across the U.S. will face higher energy rates," Nick Woolley, CEO of ev.energy, said in a statement. "The challenge for utilities is demand is rising fast, and traditional solutions — like building power stations — are slow to deliver and costly."

Enabling demand flexibility can provide a solution and reduce rates across the board, Woolley added.

Citing data from the U.S. Energy Information Administration, the report states that forecasts show a 15% increase in peak demand by 2030.

"Electric vehicles represent a massive portion of this surge," the report states. "While some forecasts predict a near-term slowdown, even conservative estimates project a 1400% increase to 60 million EVs by 2035 (Bloomberg, 2025), while others expect nearly 80 million (Edison Electric Institute, 2024)," the report states.

At the national level, EV sales in the first half of 2025 were up 1.5% year-over-year, with 607,089 vehicles sold, according to a report from Cox Automotive's Kelley Blue Book. Second-quarter figures were down 6.3% year-over-year. Cox also noted the industry is facing further headwinds with government-backed incentives ending in September and economic pressures mounting. (See Calif. Fights to Maintain ZEV Momentum.)

Why This Matters

Managed charging could provide another tool for utilities as they grapple with how to deal with the increase in peak demand.

Shutterstock

Still, "the fundamental per-vehicle value is so significant that the business case for managed charging remains urgent even under more conservative adoption scenarios, such as those highlighted in recent industry reports," according to ev.energy and Brattle's report.

A similar report by Brattle published in February found that New York could achieve 8.5 GW in "grid flexibility" measures by 2040, saving consumers more than $2 billion a year by using programs like managed charging. (See Study Finds Considerable 'Grid Flexibility' Potential in New York.)

The February study said implementing grid flexibility improvements could avoid $2.9 billion a year in power system costs by 2040, $2.4 billion of which could be returned to consumers. These cost savings come primarily from reducing how much investment in generation capacity would be needed to maintain reliability. Avoided distribution and energy costs were $408 million and $384 million, respectively.

Managed electric vehicle charging, heat pump load control and residential behind-the-meter storage all had significant potential for increasing grid flexibility, according to the February report.

In a statement on the most recent study, Ryan Hledik, principal at The Brattle Group, said: "Past analyses have shown that virtual power plants can deliver reliable power at costs up to 60% lower than traditional generators. This new research goes further — offering a rigorous, quantitative framework that confirms EV flexibility as a critical, cost-effective tool for preserving both grid reliability and affordability." ■

FERC OKs Imperial Irrigation District's WEIM Agreement

Commission also Grants CAISO Waiver Request to Extend IID's Implementation Date

By David Krause

FERC on Aug. 25 approved CAISO's Western Energy Imbalance Market (WEIM) implementation agreement with Imperial Irrigation District (IID).

The approved agreement specifies how CAISO will bring IID into the WEIM, including the costs and the scope of work involved. The commission's order notes the ISO said the plan "adopts substantially similar provisions to WEIM implementation agreements previously approved by FERC" (*ER25-2789*).

Under the agreement, IID will pay CAISO a fixed implementation fee of $120,000, and either party can terminate the agreement for any or no reason after first engaging in good faith discussions for 30 days to resolve any differences. The agreement also outlines limits of liability, notices and dispute resolution language, among other elements.

CAISO and IID are also developing an implementation agreement for the ISO's Extended Day-Ahead Market (EDAM). CAISO plans to admit IID into the WEIM and EDAM on the same day, no later than Oct. 1, 2028.

Located in Southern California, IID provides power to about 165,000 customers and operates more than 1,800 miles of transmission and 5,000 miles of distribution lines. IID in May announced its intention to join the CAISO markets, a move the utility's general manager, Jamie Asbury, said "is a significant step toward modernizing how we purchase and manage power." (*See Imperial Irrigation District Inks Agreement to Join CAISO Markets*.)

| © RTO Insider

Why This Matters

FERC's approval allows Imperial Irrigation District to join WEIM and EDAM concurrently in 2028.

In its order, FERC also granted CAISO a waiver request to allow IID's WEIM implementation date to occur more than 24 months after the implementation agreement effective date of Sept. 2, 2025, which allows the utility to join the WEIM and EDAM concurrently in 2028.

"CAISO and IID will require more than 24 months from the requested effective date of the WEIM Implementation Agreement to undertake the implementation steps needed to allow for IID's concurrent participation in WEIM and EDAM," CAISO said in its filing with FERC.

The commission said it approved the waiver because CAISO "acted in good faith" by "promptly" filed the request shortly after the ISO and IID executed their agreement and "sufficiently in advance of the proposed effective date." ■

PNM Seeks Approval for Blackstone Acquisition

Utility Promises Rate Credit, Progress on Clean Energy Goals, Economic Development Plans

By Elaine Goodman

Public Service Company of New Mexico will provide $175 million in benefits to customers and the state as part of Blackstone Infrastructure's acquisition of PNM's parent company, TXNM Energy, according to an Aug. 25 regulatory filing.

The benefit package includes a $105 million acquisition rate credit, which would be the largest in state history, according to PNM's filing with the New Mexico Public Regulation Commission (PRC). The credit would be paid to PNM customers over four years and would lower the average residential customer bill by 3.5%.

The filing includes a $25 million commitment to speed progress toward the state's energy transition goals, including funding for new technologies.

An additional $35 million would be used for economic development programs, such as job training in the utility industry. And $10 million, to be paid over 10 years, would go to the PNM Good Neighbor Fund for low-income customers.

By infusing funds into PNM, the acquisition would help it to thrive "in a rapidly changing energy environment," PNM and Blackstone said in a *press release*.

"This transaction keeps PNM rooted in New Mexico while giving it the financial strength to transform our grid and harness the opportunities to benefit our customers and communities for decades to come," PNM CEO Don Tarry said in a statement.

$11.5B Acquisition

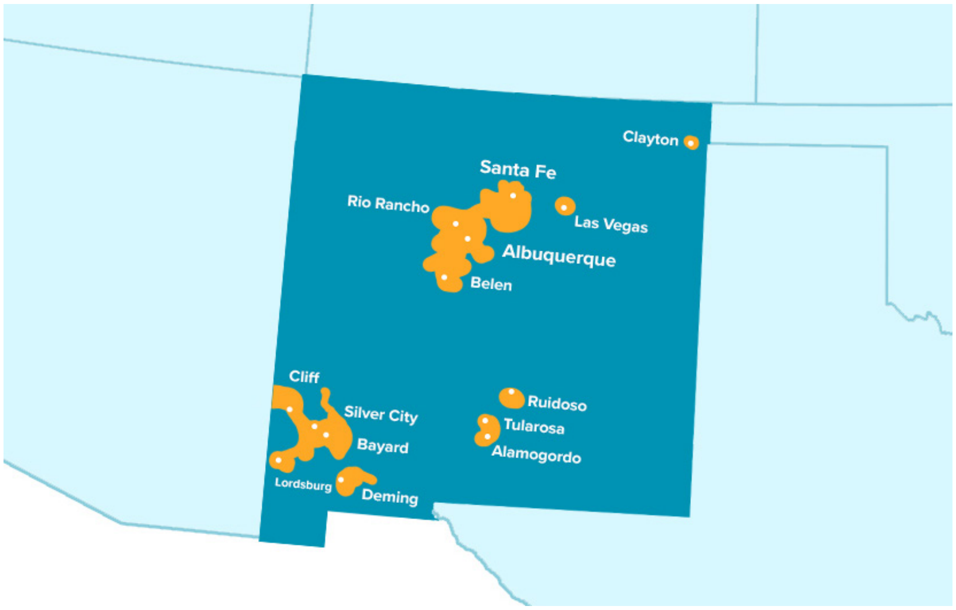
TXNM Energy and Blackstone Infrastructure announced the proposed acquisition in May. In addition to PNM, TXNM owns Texas New Mexico Power, a transmission and distribution utility in Texas that serves about 280,000 customers.

Under terms of the $11.5 billion deal, Blackstone would pay $61.25/share in cash upon closing. The purchase would be funded through equity and assumption of existing debt.

The agreement, which is subject to regulatory approvals, is expected to close in the second half of 2026. TXNM shareholders will meet Aug. 28 to vote on the deal.

On Aug. 25, TXNM Energy filed applications for approval of the proposed acquisition with the New Mexico PRC, Public Utility Commission of Texas (PUCT) and FERC.

The filing with the PUCT details $50 million in benefits, including a $35 million rate credit paid over four years, $10 million in economic development over 10 years and $5 million in additional community support.



PNM serves nearly 550,000 customers in New Mexico, making it the state's largest electricity provider. | *PNM Resources*

Why This Matters

PNM says the acquisition would help it meet key goals, including transitioning to clean energy, modernizing and hardening the grid, and building new transmission.

The FERC filing states that the acquisition would not raise rates charged to either wholesale power sales or transmission service customers.

FERC and the PUCT each have 180 days to consider the application. The New Mexico PRC doesn't have any deadlines for its review, but TXNM expects the process to take about a year.

No Layoffs Planned

According to PNM's filing with the PRC, PNM customers won't pay any costs incurred by PNM or its affiliates related to the acquisition. PNM will remain under PRC jurisdiction, and PNM and TXNM headquarters will remain in New Mexico.

PNM said it won't lay off employees or cut pay for at least three years after the deal closes. Blackstone Infrastructure has promised to hold TXNM Energy for at least 10 years.

In June, Blackstone Infrastructure completed the purchase of 8 million newly issued shares of TXNM Energy common stock at $50/share, for a total of $400 million, through a private placement agreement.

PNM previously had planned to be acquired by Avangrid. But after final approval for the deal got bogged down at the New Mexico Supreme Court, and the deadline to close the transaction was extended multiple times, Avangrid pulled out of the agreement in January 2024. (See *Lights out for Avangrid's PNM Acquisition*.) ■

Texas PUC Approves $240M in Energy Fund Grants

CenterPoint Resiliency Plan also Approved

By Tom Kleckner

Why This Matters

The Texas Public Utility Commission has selected the first four projects under the Texas Energy Fund's Outside ERCOT program. The grants total more than $240 million, about a quarter of the program's allocated funds.

Texas regulators have selected the first four projects eligible for more than $240 million in grants outside the ERCOT region as part of the state's *Texas Energy Fund*.

The Public Utility Commission *approved* staff's recommendation during its Aug. 21 open meeting. It gave Executive Director Connie Corona authority to approve the applications and enter into grant agreements, contingent upon a final review (*58492*).

The four projects under the TEF's *Outside ERCOT Grant Program* (OEGP) include two from North Plains Electric Cooperative (NPEC) and one from Southwestern Electric Power Co. SWEPCO's $200 million proposal to replace 700 miles of aging copper wire and utility poles in northeastern Texas hits the program's cap.

The other approved projects are:

- $20.4 million to NPEC for a 115-kV transmission loop in five northeastern Texas counties.
- $1.9 million to the cooperative to expand its Ochiltree Interchange, increasing service capacity in its northeastern and Panhandle regions.
- $17.7 million to El Paso Electric to deploy a continuous online monitoring project that will provide real-time analytics to improve generation availability and operational resilience.

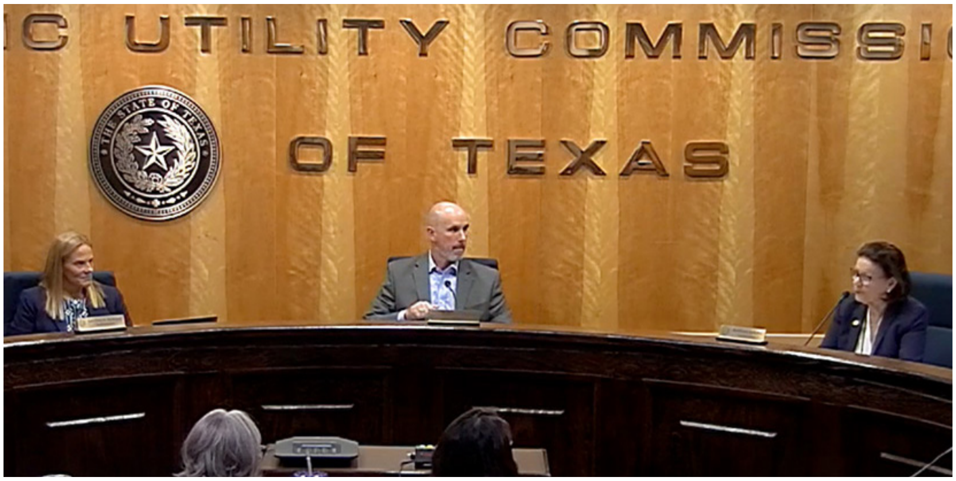
"While it's critically important to add more power to the electric grids that serve Texas, we must also do everything we can to enhance and strengthen the systems we have in place, and that's what these four projects will do," PUC Chair Thomas Gleeson said in a *statement*.

The Outside ERCOT program is one of four under the TEF. It has been allotted $1 billion by Texas lawmakers. To be eligible for awards, projects must modernize infrastructure, improve weatherization, make reliability and resiliency improvements, or address vegetation management.

PUC staff said the program has received more than a dozen applications, representing almost 50 separate projects and totaling $1.5 billion, since it was launched in May. An additional 35 applications have been started but not yet submitted.

Grants are contingent on OEGP funding availability, mutual agreement to the terms and conditions in their respective grant agreement, and their adherence to the terms and conditions set forth in their respective grant agreements. The PUC will enter into grant agreements with applicants for selected eligible projects until the program's funds are exhausted.

The commission already has granted two loans under the TEF's centerpiece, the *in-ERCOT program* created to build dispatchable generation. The program is allocated half of the TEF's $10 billion funds. (See *NRG Energy Secures $216M Loan from TEF*.)



Texas commissioners Courtney Hjaltman (left), Thomas Gleeson listen to commissioner Kathleen Jackson. | *AdminMonitor*

CenterPoint Resiliency Plan Approved

The PUC approved a *modified version* of CenterPoint Energy's $3.18 billion system resiliency plan, directing the utility to defer $217 million in cost recovery until 2029 for several resiliency measures related to strategic undergrounding, distribution pole replacements and vegetation management (*57579*).

CenterPoint originally proposed a $5.75 billion resiliency plan. However, it *reached a settlement* with commission staff, the Office of Public Utility Counsel, several Houston-area cities and other intervenors that reduced the plan's costs.

A new state law requires Texas utilities to file annual resiliency plans. CenterPoint drew anger from residents and politicians last year after Hurricane Beryl left 2.2 million of its customers without power.

The commission also:

- Approved an *amended rule* that removes the exemption currently preventing a generation company controlling less than 5% of ERCOT's total installed capacity from being considered to have market power (*58379*).
- Agreed with staff's recommendation to hold two workshops Sept. 2. The morning workshop will involve a rulemaking for net metering arrangements for large loads co-located with an existing generation resource. The afternoon workshop will take on a rulemaking that establishes large-load forecasting criteria. ■

Former Journalist Helping to Build Domestic Solar Supply Chain

Russell Gold Takes Leadership Role with T1 Energy

By Tom Kleckner

Why This Matters

Newsman-turned-solar exec Russell Gold says the solar industry will be important in meeting the nation's "insatiable" demand for energy and that building a domestic, affordable and renewable energy system is the "challenge of our time."

What does a journalist, two-time Pulitzer Prize finalist and author of two books do after three decades writing for respected publications like the *Wall Street Journal* and *Texas Monthly*?

If you're Russell Gold, you leave your career as an energy reporter to join a company manufacturing solar technology and building an integrated domestic supply chain for solar and batteries.

Back in the 1970s and 1980s, when Woodward and Bernstein's "All the President's Men" was required reading for aspiring journalists, fellow ink-stained wretches of the Fourth Estate might have said Gold was leaving for the "dark side" of public relations. He says he simply is seeking a new direction in life.

"I was looking for a change of scenery. Like many people getting into their early 50s, I wondered what other challenges there might be," Gold said.

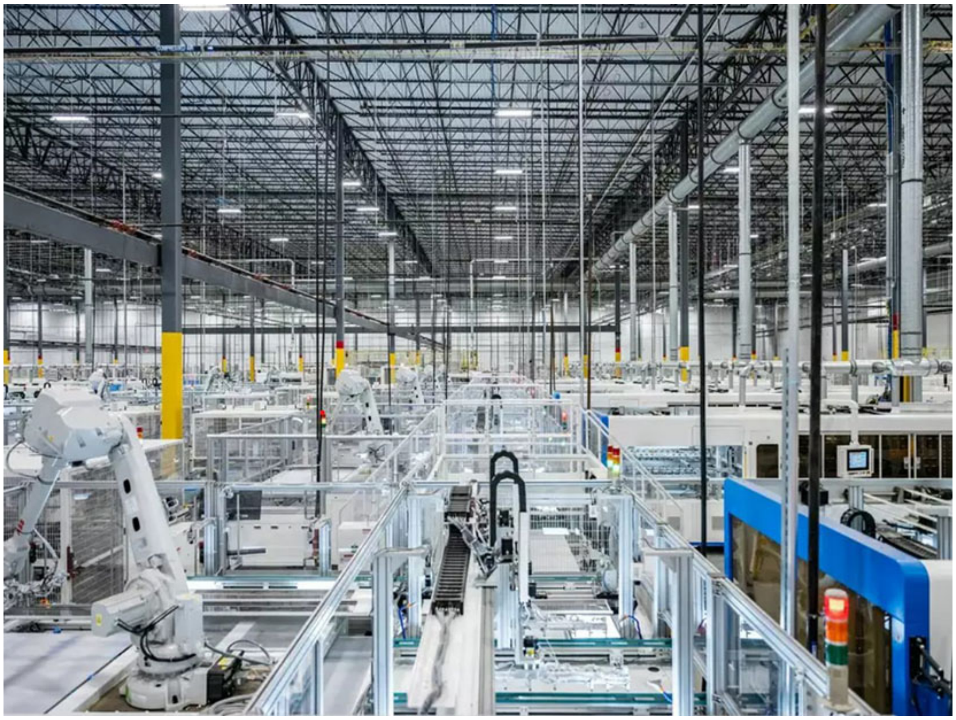
He has found his challenge: helping build an American supply chain that creates jobs and an abundance of energy. "In this day and age, it's a great challenge and one I eagerly signed up for," he said.

In May, Gold joined T1 Energy as executive vice president of strategic communications. The company lauded him as a "respected leader and prominent voice" in the solar industry.

"The challenge of our time is to build a domestic, affordable and renewable energy system, and T1 is at the forefront of that effort," Gold *said* at the time.

Previously known as Freyr Battery, the company *rebranded itself* as T1 Energy in February and relocated to Austin, Texas. The company last year acquired the U.S. assets of a Chinese company, Trina Solar, which included a 5-GW solar panel manufacturing facility near Dallas. Texas Gov. Greg Abbott (R) mentioned T1's Dallas factory while celebrating *the state's 12th Gold Shovel Award* for achievement in job creation and capital investment.

Gold said the facility, G1 Dallas, employs 1,000 people. T1 plans to *start construction* on another facility in Rockdale, east of Austin. The $850 million G2 Austin factory is expected to be one of the largest solar manufacturing facilities in the U.S. and will create 1,800 new direct advanced manufacturing jobs, T1 says.


T1 Energy's manufacturing plant near Dallas | *T1 Energy*

"It's jobs, but it's also advanced manufacturing," Gold said, referring to G1 Dallas. "If you go to the factory, you'll see a mix of people and robots and AI working together to drive down the cost of panels."

According to English think tank Ember, the cost of solar power combined with batteries *dropped 22% in 2024 alone*, and 43% since 2019. That's no surprise to Gold.

"The cost of solar is always coming down," he said. "Right now, there's no question that solar is among the most cost-competitive energy source available at scale."

T1 CEO Daniel Barcelo says more than 80% of new electric capacity in the U.S. in 2024 came from solar and battery technology. The company has stayed ahead of the curve, weaning itself off Chinese products when it saw they would be cut off from U.S. tax credits.

Gold said T1's "mantra really is our mission:" building domestic solar and battery supply chains to invigorate America with scalable, reliable and low-cost energy.

"We feel it's really important for jobs and energy security that those solar panels be made from a supply chain in the U.S.," Gold said. "We want to provide a lot of energy. We want it to be affordable, and we want to make sure that no one around the world can cut off our supply chain."

Asked how a supply chain is built, Gold said there are four steps to making solar panels. Start with polysilicon, which T1 sources out of Michigan. The polysilicon is turned into wafers and wafers are turned into cells. Cells are made into solar panels. Gold said cells will be made at G2 and the company is "actively" investigating how to produce wafers in the U.S.

Glass, glue, weather-stripping, other petroleum products and aluminum all go into the final product: solar panels.

"So, we're looking for and building suppliers into a supply chain that's all domestic and not imported," Gold said.

T1 may have completed that task. It *said* Aug. 15 it has reached an agreement with glass maker Corning to source wafers beginning in the second half of 2026. The deal expands on an existing supply contract for solar-grade polysilicon and establishes a domestic solar supply chain connecting polysilicon, wafers, cells and panels.

The wafers will be used at G2 Austin when it is up and running. The cells will be assembled in G1 Dallas, the companies said.

"We're really a poster child that it's difficult, but it can be done. We just need to put in the work," Gold said. "It's exciting to be part of a broader trend toward creating an emerging solar industry."

Gold graduated from Columbia University in 1991 with a degree in history and soon landed a job as a suburban correspondent for the *Philadelphia Inquirer*. He transitioned into investigative journalism with a focus on energy, first for the *San Antonio Express-News* and then for the *Wall Street Journal*. Gold joined *Texas Monthly* in 2021, just in time to cover the aftermath of Winter Storm Uri after it almost brought the ERCOT grid to its knees.

His coverage of the Deepwater Horizon disaster and Pacific Gas and Electric's Camp Fire has earned him numerous awards and honors, including the *Gerald Loeb Award* for business and financial journalism twice. Gold's books include "The Boom," a history of fracking, and "Superpower," about Grid United CEO Michael Skelly's quest to build an HVDC line to ship wind energy to urban centers. (See *Book on Tx Developer Transmits Climate Hope*.)

Now, he's part of the story, helping explain the importance of solar energy in helping meet the growing demand from AI and data centers.

"For the next six or seven years, we're going to need an abundance of energy, whether it's coming from new gas or new nuclear or new geothermal or predominantly coming from two sources: solar and any existing gas projects," Gold said. "But let's not fool ourselves. If we want our economy to grow and remain affordable and we want to avoid 1970s energy prices, we will need solar over the next few years."

Russell Gold (right, with Grid United's Michael Skelly) | © *RTO Insider*

The budget reconciliation bill that passed Congress in July sunsets the clean energy sector's production and investment tax credits and poses a significant threat to wind and solar power development, industry observers said. The bill boosts thermal projects, but a backlog for gas turbines extends into next decade. (See *Senate Passes Trump's Big Bill that Slashes Clean Energy Tax Credits*.)

According to *pv magazine*, nearly $8 billion in U.S clean energy investment and 16 large-scale factories *were canceled* during the first three months of 2025. Gold noted that the production manufacturing credit was left untouched, saying, "That's our primary tax credit."

"I think it remains to be seen what impact that will have on solar growth in the United States, for a number of factors," he said. "First of all, the production tax credit isn't going away immediately. Demand for energy is insatiable, and we need to keep growing … to have an abundance of energy. So, we feel very strongly that solar and storage are absolutely critical parts of our energy growth and will continue to be."

The industry did get a small boost when the U.S. Treasury Department released new rules on new wind and solar construction qualifying for tax credits. While the rules removed a 5% safe harbor provision, they were not as stringent as originally feared. (See *IRS Guidance on Wind and Solar Credits Not as Bad as Feared*.)

Gold said that based on T1's initial review of the Treasury rules, "We believe there will be a good pipeline of demand for our modules. We've already seen, and are continuing to seek, strong demand in '25 and '26."

"This is an incredibly challenging opportunity, but also incredibly important one to build an American solar champion," he said. "That's what we're really trying to do."

Domestic solar, he added, "will create jobs and affordable energy." ■

Ontario Nodal Market Nearing 'Steady State' After Nearly 4 Months

IESO to Look for Structural Improvements After Correcting Implementation Problems

By Rich Heidorn Jr.

Nearly four months after the launch of Ontario's nodal market, IESO officials say they are shifting from correcting implementation problems to seeking improvements to ensure the new model meets the goals of increasing market efficiency, transparency and competition.

Candice Trickey, director of Market Renewal Plan readiness | *IESO*

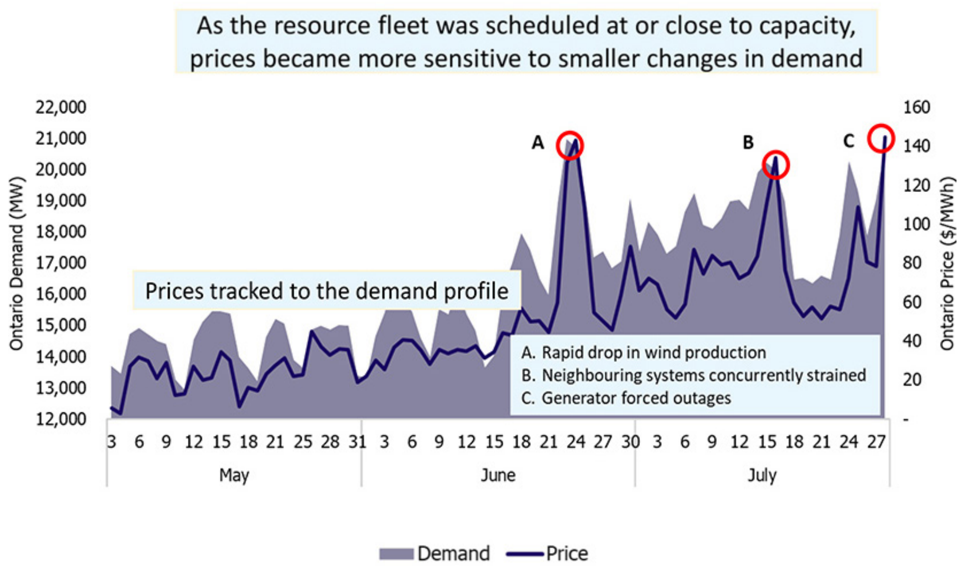
"We're getting … pretty close to what I would call more of a steady state … where we'll be able to start to move from … addressing the day-to-day issues that come up for things that didn't quite get implemented exactly as planned, to [looking at] the longer term," Candice Trickey, director of Market Renewal Plan readiness, said in a briefing Aug. 21, the first in a promised quarterly series of updates. "How are things progressing? Are we seeing the things we wanted to see? … And where we aren't, what do we need to [do to improve] that?"

The Renewed Market, which launched May 1, created a financially binding day-ahead market (DAM) and about 1,000 LMP nodes. (See *Ontario Nodal Market Operating as Expected at 1-month Mark*.)

Despite some implementation problems, IESO said the market has been working well, with prices strongly correlated to demand.

Why This Matters

Ontario's nodal market, which created a financially binding day-ahead market and about 1,000 pricing nodes, is intended to increase market efficiency, transparency and competition.



IESO said market prices had a very strong correlation to demand. | *IESO*

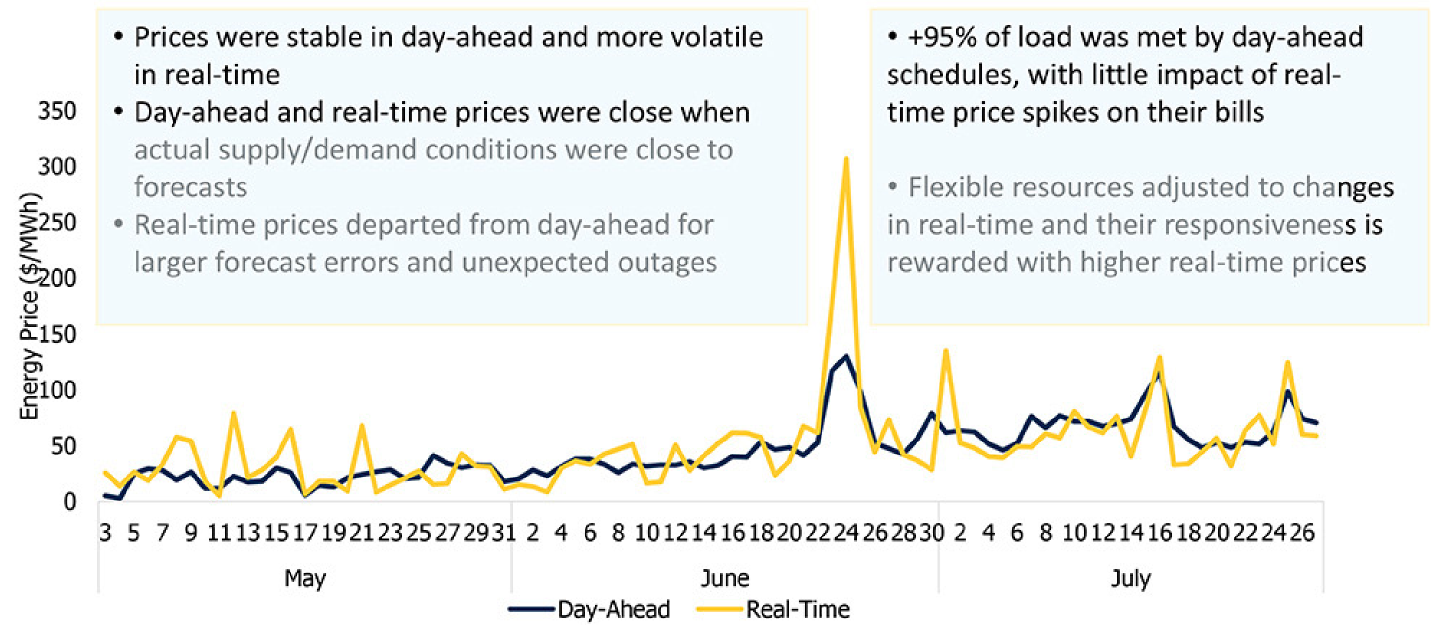
Data Points

Some data points as the market nears the four-month mark:

- Nearly 30 traders have registered to transact in the virtual market, which allows them to submit hourly bids and offers in nine zones. Problems completing traders' authorizations delayed the launch of the virtual market from May 8 to May 13. One large consumer has registered as a price-responsive load. Other organizations have begun the process of registering for the two new participation types.
- All required participants have registered reference levels under market power mitigation rules, with some refining their values based on their experience in the market. Reference levels include energy and operating reserve prices and resources' energy ramp rates and lead times. The Market Power Mitigation Working Group has reduced its meeting frequency to monthly, with "no significant issues" identified.
- IESO said it has been issuing settlement statements and invoices within the required timelines, although increased processing times have resulted in invoices being issued later in the day than preferred by participants, an issue the ISO is working to address. The ISO created a *Settlements Notifications* webpage to advise participants of updates.
- Participant inquiries have increased under the new market. IESO said its Customer Relations unit has answered 80% of inquiries within two business days, although more complex questions have taken "much longer." The ISO said 40% of market participants responded to its final market readiness survey, with nearly 90% saying IESO's Customer Relations or Marketplace Training were "very" or "somewhat" effective. About 63% of respondents reported they generally are "comfortable operating," and 35% said that "non-critical" operations still are incorporating changes. Only a few organizations reported they were "struggling to operate effectively," IESO said.

'Defects'

As expected, Notices of Disagreement have increased since the market launch. The ISO has confirmed its initial statements in two-thirds of cases and attributed one-third to defects that have been corrected. The grid operator is working



Real-time prices have been more volatile than the day-ahead market, with prices converging when actual conditions matched forecasts, and diverging when there were large load forecast errors or unexpected outages. | *IESO*

through a backlog of disagreements.

Most of the defects affected small groups of participants, such as price responsive loads and resources eligible for generator offer guarantees — non-quick-start resources that commit to economically scheduled hourly generation commitments in advance of real-time (RT) dispatch.

But one defect, caused by a calculation error regarding residual uplifts, had a widespread effect. Although the two-settlement energy settlement amounts were calculated correctly, the day-ahead and real-time residual uplifts were calculated incorrectly and distributed to loads and exporters, resulting in adjustments to four uplift charge types. The ISO issued a notice Aug. 12 identifying the issue, the affected charge types and how resettlement will be completed.

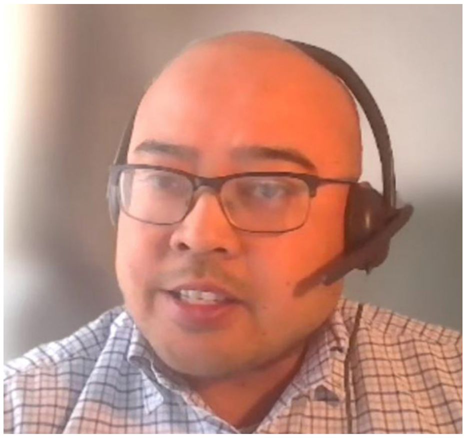
Trickey said the rate of new defects in market systems has fallen from the first few weeks and that most were addressed with interim "workarounds" to avoid market effects.

One of the workarounds involved the five-minute interval Ontario Demand values reported in real time, which were overstated in some "limited circumstances." IESO's workaround "effectively adjusted forecast demand to largely mitigate this defect," it said.

The ISO said some defects had no effect because workarounds were implemented, while others affected market outcomes briefly and required it to administer prices or correct schedules before settlement.

More complex defects required "extensive assessment" to determine if there was a material effect and could not be completed prior to settlement.

Thus far, the ISO said, two of those assessed had material effects necessitating the issuance of dispatch scheduling errors (DSEs): an incorrect calculation of the external congestion and net interchange scheduling limit price components for May 1-4; and an incorrect limit considered in the DAM for the ONT-PQAT interface on May 6. DSEs are issued when problems are discovered after settlements are issued; they allow the ISO to provide compensation to harmed parties but do not change prices.



Joseph Ricasio, a member of IESO's control room team | *IESO*

Another five issues requiring extensive assessment are outstanding; the ISO said it likely will take another three to six months to determine whether these had material effects requiring DSEs.

Market Results

IESO officials said market results generally have been in line with expectations.

The market began during the "freshet," the annual influx of water from spring rainfall and melting snow. Many hydropower projects must exit the operating reserve market and operate as "must-run" generators in spring because they have to flow the excess water through their turbines. (See *Operating Reserve Prices Surge in Ontario*.)

Summer brought its own challenges, Joseph Ricasio, a member of IESO's control room team, said during the webinar. Hot weather sent the province's demand soaring above its 2024 peak of 23,852 MW on seven occasions, with peaks as high as 24,862 MW. "I don't remember the last time we received a lot of successive heat waves," he said.

Between June 23 and 24, Ontario shifted from a net exporter during peak hours — as strong wind generation allowed it to ship energy to New York and Michigan — to a net importer as wind diminished.

It was a net importer on July 14-16 due to economic conditions and on July 27-29 as two large generators were "forced offline."

"The generation and transmission performed very well this summer," Ricasio said. "One advantage [of] being a net exporter is that it gives us a lever to address any adequacy concerns, and that's because if it's needed, we can curtail those exports."

Despite the challenges, Ricasio said, the financially binding DAM has improved IESO's ability to commit adequate generation for the next day. Some Level 1 Emergency Energy Alerts — a notice that all available generation resources are committed — have been identified based on day-ahead results, IESO said. "This gives advance notice to your neighbors that we may need their help," Ricasio said.

'Non-intuitive' Results

Trickey said numerous participants have questioned "non-intuitive or unusual" market results. Some identified defects, while others were a result of the challenging summer temperatures and the new market's multi-interval optimization.

"In an LMP market, the [offer] price is certainly an important determinant. But because we're looking at optimizing over many, many intervals, [there can be] a difference in what the scheduling algorithm and the pricing algorithm are looking at," she said. "So, you might see an offer close to the margin that appears uneconomic that gets scheduled."


Director of Markets Darren Matsugu | *IESO*

Director of Markets Darren Matsugu said the market had produced prices "reflective of system conditions and efficient resource schedules" with real-time and day-ahead prices converging when actual conditions matched forecasts, and diverging when there were deviations in real time due to large load forecast errors or unexpected outages. Although real-time prices were more volatile than day-ahead, more than 95% of load was met by day-ahead schedules, minimizing the price effect on consumers, the ISO said.

"Moving from the mild temperatures in May — where we saw … seasonally low demands and abundant supply — into what's turned out to be a very hot summer, we've seen an associated increase in entry market prices, which is exactly what we would expect," Matsugu said.

"We also observed higher natural gas prices over the summer, and as gas is often the marginal resource during these two periods, that also has upward pressure on market clearing prices," he added.

Prices have consistently separated between the north, where bottled hydro supply can suppress prices, and the transmission-constrained south.

"This past May when demand was relatively low and we had substantial baseload generation available, we had very few intermediary peaking resources that were already online and available to increase output immediately," he added. "But what we have seen is demand has increased over the summer, and more and more of those resources are being committed ahead of real time, either in day-ahead or in pre-dispatch. This increases the amount of incremental flexibility that can be dispatched on the system, if required."

An average of 80 to 90% percent of non-quick start gas generators dispatched in real time — units that need one to six hours to start up and synchronize with the grid — were scheduled in the DAM over the first three months, providing grid operators and market participants "a clearer view and financial certainty for the next day's operations while also leaving room to adjust to forecast uncertainty and outages in real time," the ISO said.

Challenges in Scheduling of Pseudo Units

While the experience generally has been positive so far, "it isn't perfect," Ricasio said, citing IESO's difficulties with pseudo unit (PSU) configurations, which model the mechanical interdependencies of combustion turbines and steam turbines.

Under the Renewed Market, PSU modelling is applied for DAM, pre-dispatch and RT timeframes for commitment, scheduling and dispatch.

IESO notified affected generators of workarounds to address the issues and said it is working on permanent fixes.

No Major Changes Expected

Matsugu said the market thus far has worked as designed to reduce out-of-market payments and increase efficiency.

"I do expect that over time, there'll be some fine tuning that may be eventually required on these things, as is to be expected with any market — and particularly given the significance of the change that we've introduced with Market Renewal," he said. "But at this point, there are no major design issues that require immediate fixes, just something that we'll continue to pay close attention to."

Matsugu cautioned that IESO had only two seasons of experience with the new market rules, saying it will gain valuable knowledge in the coming fall and winter.

"It is premature, I think, to draw too much based upon the still very short time frame that we've been operating," he said. "We are still working toward … a steady state, where we can see the market performance under a diverse set of outcomes and conditions. [And] the participants themselves are still establishing their own competitive bid and offer strategies."

Participants' Questions

ISO officials answered several questions from stakeholders during the Aug. 21 presentation. Aaron Lampe, of Workbench Energy, asked about the effect of the market on pre-dispatch prices.

Matsugu said comparing PD prices before and after May 1 is "really comparing apples to oranges [because] in pre-market, our pre-dispatch was doing a one-hour optimization and not looking out across the balance of the day."

"The only thing in common between pre-market pre-dispatch and our current pre-dispatch is really just what it's called," he added.

Rob Coulbeck, of Red Jar Energy Partners, said the ISO's pre-dispatch three-hour look ahead was restrictive and asked if it could add another hour for import and export transactions that don't clear in the DAM.

"I think that probably falls in the bucket of future design enhancements," responded Matsugu. "There's probably a whole bunch of different things that we can start to consider once we're satisfied that the current market is performing." ■

Ontario to Expand Industrial Energy Efficiency Program

IESO Demand-side Management Program to Increase Incentives, Loosen Participation Timelines

By Rich Heidorn Jr.

IESO will expand its industrial demand-side management program in September, increasing funding and allowing both larger and smaller participants than currently permitted.

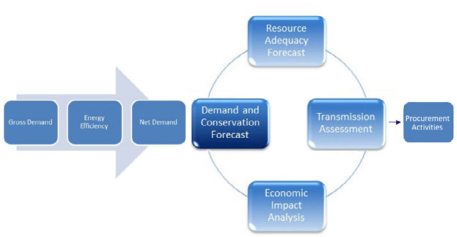
The electric demand side management program (eDSM) incentives are intended to help industrial, municipal, institutional and health care organizations to implement "proven, commercially available" energy savings technologies that would otherwise be too costly.

The new program will triple the incentive cap to $15 million from $5 million per project, and allow participants five years to complete installation, up from three years.

The minimum savings to qualify will be reduced to 600 MWh/year from 2,000 MWh/year. For the first time, the program also will provide funding for feasibility studies (50% of total costs, up to $100,000).

The grid operator is also making the application process simpler, with a single sign-off application and a first-come-first-served intake.

The program is part of IESO's $1.8 billion 2025–2027 eDSM plan, which is forecast to reduce peak demand by 900 MW and save 4.6 TWh of electricity by 2027. Ontario, which is projecting 75% load growth by 2050, plans to spend $10.9 billion under a 12-year funding commitment that began in January, tripling the province's historical EE spending. (See *Ontario Integrated Energy Plan Boosts Gas, Nukes* and *IESO Seeking Feedback on Commercial HVAC Demand Response Program*.)



The expanded eDSM industrial program is designed to tap more of the energy efficiency savings identified in the 2022 Achievable Potential Study, building on the 2021-24 Conservation and Demand Management Framework and program revisions in 2023. | *IESO*

The new industrial program was informed by the province's experience under its Save on Energy program, a review of industrial programs in other regions and stakeholder feedback, Nicole L. Hynum, supervisor of IESO's Custom Business Programs, said in an Aug. 21 webinar.

"Some customers [in the industrial energy efficiency program] did identify some challenges with the program, including funding cycles that maybe didn't align with your capital planning cycles [and] a more risky application process that didn't work for industry because it was competitive," Hynum said. "The thresholds for the project size were … too large for some industries, and the incentive levels were competing with other demand-side management programs and were less than those other competing offers. So, you know, it impacted participation."

Under the former program, incentives were proposed by participants based on their project needs. The new program will pay the lesser of $300/MWh ($450/MWh in areas having "local needs"), 75% of eligible project costs or the amount that would provide a project payback of one year.

A project that saves 5,000 MWh/year in a local needs area would receive incentives of up to $2.25 million (5,000 × $450), subject to the eligible cost payback test and a $15 million cap.

Participants can seek an exception to the $15 million cap based on their business case.

Eligible projects must save electricity for at least four years after the end of a one-year measurement and verification (M&V) reporting period.

Why This Matters

The industrial energy efficiency program is part of IESO's $1.8 billion 2025–27 eDSM plan, which is forecasted to reduce peak demand by 900 MW and save 4.6 TWh of electricity by 2027.

Participants will receive 50% of their project incentive based on a review of their first-quarter M&V report and the balance after a review of the year-one M&V report.

Ineligible to participate are:

- Electric generation projects, except approved waste energy recovery where the recovered energy offsets the facility's own load;
- Behind-the-meter storage, unless the storage improves the efficiency of other project components, resulting in net electricity savings;
- Lighting projects (which can receive funding through the Save on Energy Instant Discount Program);
- Fuel switching, unless approved by IESO; and
- Local distribution company infrastructure efficiency measures.

The final design of the program is expected to be approved in early September, with the program launching late in the month.

"This is year one of a 12-year framework," Hynum said. "We will no doubt be enhancing this program to meet evolving marketplace and electricity system needs." ■

Stakeholders Frustrated by Lack of Details on Toronto DSM Study

By Rich Heidorn Jr.

IESO officials say they will release more information on how the ISO constructed its study of the potential for incremental energy savings in Toronto after stakeholders complained they lack enough details to comment meaningfully on the analysis.

At a *webinar* Aug. 21, IESO said it and Toronto Hydro could cost-effectively secure 219 MW of incremental summer demand savings and 50 MW of incremental winter demand savings through energy efficiency, demand response and behind-the-meter DER programs.

The savings are in addition to the forecast 847 MW (summer) and 757 MW (winter) of future electric demand side management (eDSM) program savings already reflected in the Toronto Integrated Regional Resource Plan (IRRP), according to the study, which was conducted with consulting firm ICF.

Why This Matters

The study results will impact recommendations for how non-wire alternatives can defer or reduce the need for more electric infrastructure.

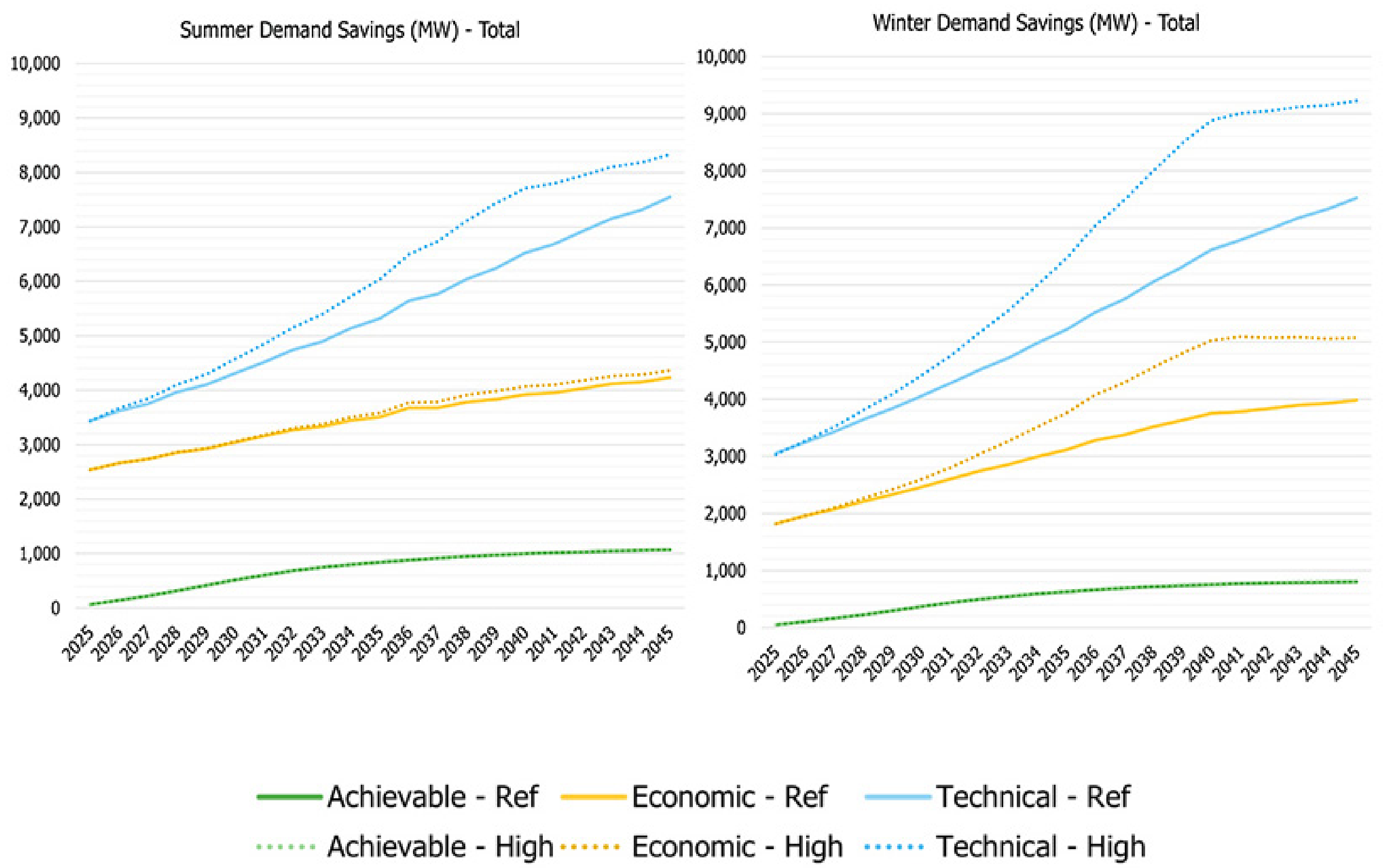
The results from the ISO's draft Local Achievable Potential Study will affect recommendations for how non-wire alternatives can defer or reduce the need for more electric infrastructure. "The results show that incremental eDSM alone is not able to meet Toronto's needs," the ISO said in a *presentation*.

IESO asked for feedback on the results by Sept. 11. The final report is set to be published on the Toronto Regional Planning *website* in October.

But several stakeholders said they would be unable to respond intelligently based on the information the ISO has released to date.

"It would be very helpful if you could provide us with the draft report that you've got so we can look at your input assumptions, look at your analysis and give you meaningful feedback," said Jack Gibbons, chair of the Ontario Clean Air Alliance. "Because some of your assumptions may be wrong. Some of your analysis may be wrong. And we don't want to just take your findings that you've given us today on faith."

IESO's Tom Aagaard noted that the ISO received feedback on its input assump-



The IESO study found total achievable potential savings from energy efficiency, demand response, and behind-the-meter DER in 2045 would be 1,066 MW in summer and 806 MW in winter under the reference scenario. | *IESO* tions in a webinar in December and said the ISO still was refining its conclusions. "We'll have to take back [to see] what we're able to share sooner."

"You've got a draft report from ICF. I don't see why you can't just share it now and be transparent," Gibbons persisted. "What harm is it going to do to give us what you've got now?"

Keith Brooks of Environmental Defence, Chris Caners, general manager of renewable energy co-op SolarShare, and David Robertson, of Seniors for Climate Action Now, agreed with Gibbons.

"Without an understanding of what the final assumptions are in more detail, it's really, really impossible to give meaningful feedback," Caners said.

IESO responded in an email the day after the webinar, saying it would work with ICF "to expedite the release of more detailed information on methodology and assumptions, including measure characterization and more information on achievable potential established from economic potential results." The information will be posted on the Toronto Regional Planning engagement *website*.

Methodology

The study used two load forecasts:

- A reference scenario assuming a steady increase in demand based on current policies and growth in EVs and electrified heating and "low/steady growth" of data centers.
- A high-electrification scenario that assumes Toronto will meet its net-zero targets for buildings by 2040 (with 30% EV adoption by 2030 and 100% by 2040) and see "elevated" data center growth.

For each scenario, the study identified three levels of potential electricity savings:

- Technical Potential. Savings from implementing all technically feasible measures regardless of cost-effectiveness and customer awareness.
- Economic Potential. Savings from technically feasible measures that are cost-effective based on avoided generation (capacity and energy) and transmission costs and forecasted retail rates.
- Achievable Potential. Savings that realistically can be acquired based on expected adoption rates considering market barriers and customer awareness.

The study used "digital twins" of Toronto's building stock, to which DSM measures were applied. The resulting savings were simulated at the building level and aggregated to the transformer station for each scenario.

Draft Results

In 2045, the study concluded that achievable savings under the reference scenario were 1,066 MW in summer and 806 MW in winter:

- Demand response (including EV charging, HVAC equipment and water heaters) had an achievable potential of 440 MW in summer and 324 MW in winter under the reference scenario. IESO said the difference in achievable potential between the reference and high-electrification scenarios is modest because the reference case includes significant heating electrification and because of the poor cost-effectiveness of EV demand response programs due to time-of-use pricing.
- Energy efficiency (heat pumps, HVAC, lighting, appliances, weatherization and hot water) could save 605 MW (summer) and 471 MW (winter).
- Behind-the-meter distributed energy resources (including battery storage and solar) could save 21 MW (summer) and 11 MW (winter). The low winter potential reflects the "limited value of solar to meeting winter needs," the ISO said. Technical and economic potential match because measures in current Save on Energy programs including solar and solar-plus-storage were judged cost-effective. The reference and high scenarios had identical potential because the technical potential is affected by factors like usable rooftop area for solar rather than load.

Robertson and Brooks questioned the gaps between economic and achievable potential.

"It's hard for us to give feedback on the results if we don't understand how you arrived at them," Brooks said.

"It would be really helpful and useful if there was something in your reports and presentations that talk about how do you close the gap," said Robertson.

Existing Measures

IESO said the achievable savings in the study were muted because the Toronto IRRP already assumes 847 MW (summer) and 757 MW (winter) of new peak demand savings in 2045 from eDSM programs. In January, the Ontario government announced it would spend up to $10.9 billion on its eDSM programs through 2036.

The IESO and Toronto Hydro's EE programs already have reduced peak demand by 800 MW in the past 15+ years.

The city's Green Standard's high energy performance requirements reduce the amount of additional cost-effective efficiency opportunities in new construction.

"Robust" participation in net metering, *microFIT* and other DER programs reduce the remaining rooftop solar potential, the ISO said.

Vehicle-to-grid

Another point of contention was the ISO's decision to exclude bidirectional charging measures (vehicle-to-grid) from the study. The ISO said it could not properly model V2G based on current information and lacked confidence "that a program of meaningful scale could be delivered cost-effectively in the near future" because of the limited availability of vehicles capable of bidirectional charging, uncertain customer acceptance, costs and technological barriers.

Robertson questioned the ISO's conclusion, saying "a study [with a] horizon to 2045 should anticipate developments" such as V2G.

Aagaard said it would be "kind of reckless" to include savings from V2G based on current information.

"We have very, very limited core data [to make] really important modeling assumptions to understand how much technical potential is actually out there. How many vehicles are actually going to have bidirectional charging capability? Do customers actually want this? Will [they] be willing to participate in programs when they're called upon?" he said. "There's just a million kind of consumer choice factors that come into play. … To include it in the modeling would be like really pulling numbers out of a hat." ■

BOEM Slaps Stop-work Order on Revolution Wind

704-MW Wind Farm off New England Coast is 80% Complete

By John Cropley

The Trump administration has slapped Ørsted with a stop-work order on Revolution Wind, a 704-MW project off the New England coast that is 80% complete.

The Aug. 22 order by the Bureau of Ocean Energy Management cites national security interests and potential interference with reasonable uses of territorial waters.

It is the latest move by the administration to thwart renewables development, and one of the harshest.

President Donald Trump delivered a pro-fossil, anti-renewable message during his campaign but reserved a particular contempt for "windmills." Hours after his inauguration Jan. 20, he delivered on his rhetoric, directing a halt to future offshore wind leasing and a review of existing offshore wind permits.

Acting BOEM Director Matthew Giacona cited that Jan. 20 memorandum in his letter to Ørsted North America on Aug. 22. He forbade further activity on the Offshore Continental Shelf until BOEM completed a review.

Ørsted said later Aug. 22 it would comply with the order and is evaluating all options in a range of scenarios, including legal action.

It said the multibillion-dollar project was 80% complete, with 100% of turbine foundations and 45 of 65 of turbines installed. It had been targeting start of commercial operation in the second half of 2026; the 704-MW facility would send emissions-free electricity to Connecticut and Rhode Island.

During an Aug. 11 conference call with financial analysts, CEO Rasmus Errboe was asked if he was certain the Trump administration would not try to block Revolution or Ørsted's other active project, the 924-MW Sunrise Wind, which is targeted for completion in 2027.

Errboe declined to speculate.

The administration slapped a similar stop-work order on Empire Wind 1 in April, causing hundreds of millions of dollars in losses for its developer, Equinor. (See *Feds Move to Halt Construction of Empire Wind 1* and *Equinor Takes $1B Impairment on U.S. Offshore Wind*.)

The move against Empire, a project that was fully permitted after years of review, sent shock waves through the renewables industry. There was widespread speculation that it was an attempt to twist the arm of New York's governor to allow permitting of two natural gas pipeline projects the state previously had rejected, as New York is counting on Empire (and Sunrise) as part of its decarbonization strategy. (See *BOEM Lifts Stop-work Order on Empire Wind*.)

But the Empire stop-work order never really was explained, other than a vague mention of flawed science and rushed approval. Journalists who requested a copy of a study that purportedly justified the move were repeatedly rejected, then were *provided a fully redacted copy* four months later.

Errboe cited the Empire stop-work order as a turning point — it immediately made Ørsted's attempts to land a financial partner for Sunrise untenable, causing Ørsted to announce a need to raise $9.3 billion, causing its stock value to plunge. (See *Ørsted to Raise $9.3B, Self-finance Sunrise Wind*.)

The company said in a news release Aug. 22 it will in due course update the markets on the potential impact of this latest setback.

Giacona in his letter said BOEM is seeking to address "concerns related to the protection of national security interests" and "interference with reasonable use" of the offshore waters.

He did not elaborate, but both points speak to some of the many policy moves the Trump administration has taken to stop wind power development:

The Department of Commerce on Aug. 13 initiated an investigation to determine the effects on national security of imports of wind turbines and their parts and components.

BOEM's parent agency, the Department of the Interior, announced a sweeping overhaul of offshore wind rules Aug. 7; an order to rein in wind and solar projects Aug. 1; cancellation of wind energy areas designated on 3.5 million acres of seabed on July 30; and an end to preferential treatment of wind energy July 29, among other steps. (See *Dept. of Interior Launches Overhaul of OSW Regs*, *Trump Administration Takes Another Swing at Wind Power* and *Feds Pile on More Barriers to Wind and Solar*.)

Late Aug. 22, the National Ocean Industries Association *decried this latest attack*: "Revolution Wind is already under construction and nearly complete, representing years of planning, billions in private investment and significant progress for America's offshore energy supply chain. Any pause or uncertainty at this stage could ripple across jobs, contracts and communities already benefiting from the project."

The Oceantic Network *called it an illegal move* that threatened American jobs and energy dominance: "This dramatic action further erodes investor confidence in the U.S. market across all industries and undermines progress on shared national priorities — shipyard revitalization, steel and port investments, and energy dominance. In fact, halting work on Revolution Wind will drive up energy costs for consumers, idle Gulf Coast vessel operators that have invested hundreds of millions of dollars in new or retrofitted vessels and jeopardize the livelihoods of union workers." ■

Why This Matters

The move is the latest and one of the most drastic steps by the Trump administration to thwart wind power development.

A load of 97-meter blades for the Revolution Wind project is delivered in 2024. The project, which is now nearing completion, was slapped with a stop-work order by the Trump administration Aug. 22. | *Siemens Gamesa*

ISO-NE Warns Halting Revolution Wind Boosts Reliability Risk

704-MW Project is Part of Capacity Calculations, Faces BOEM Stop-work Order

By John Cropley and Jon Lamson

Why This Matters

The Trump administration's attacks on renewable energy are altering calculations on future grid capacity.

ISO-NE warned that any significant delay of the Revolution Wind project will increase risk to the reliability of the New England grid and undermine the region's economy.

The grid operator's Aug. 25 statement came three days after the Trump administration halted construction of the 704-MW wind farm off the Rhode Island coast, citing national security interests and potential interference with reasonable uses of territorial waters. (See *BOEM Slaps Stop-work Order on Revolution Wind*.)

The project is 80% complete after more than a year of construction and had been on track to start commercial operation in the second half of 2026.

While President Donald Trump's animosity to offshore wind and other renewables is well known, and his policy moves to thwart future development have become commonplace, halting the work in progress on a multibillion-dollar project raises the campaign to another level.

Offshore wind proponents, labor unions, environmentalists, local politicians and others decried the shutdown of construction on Revolution Wind, which is contracted to send 400 MW to Rhode Island and 304 MW to Connecticut.

Grid Asset

The nation's only completed and operational utility-scale offshore wind array, South Fork Wind, has reported strong performance — a 53% capacity factor in the first half of 2025. It is adjacent to Revolution Wind, has the same developer and uses the same turbine technology.

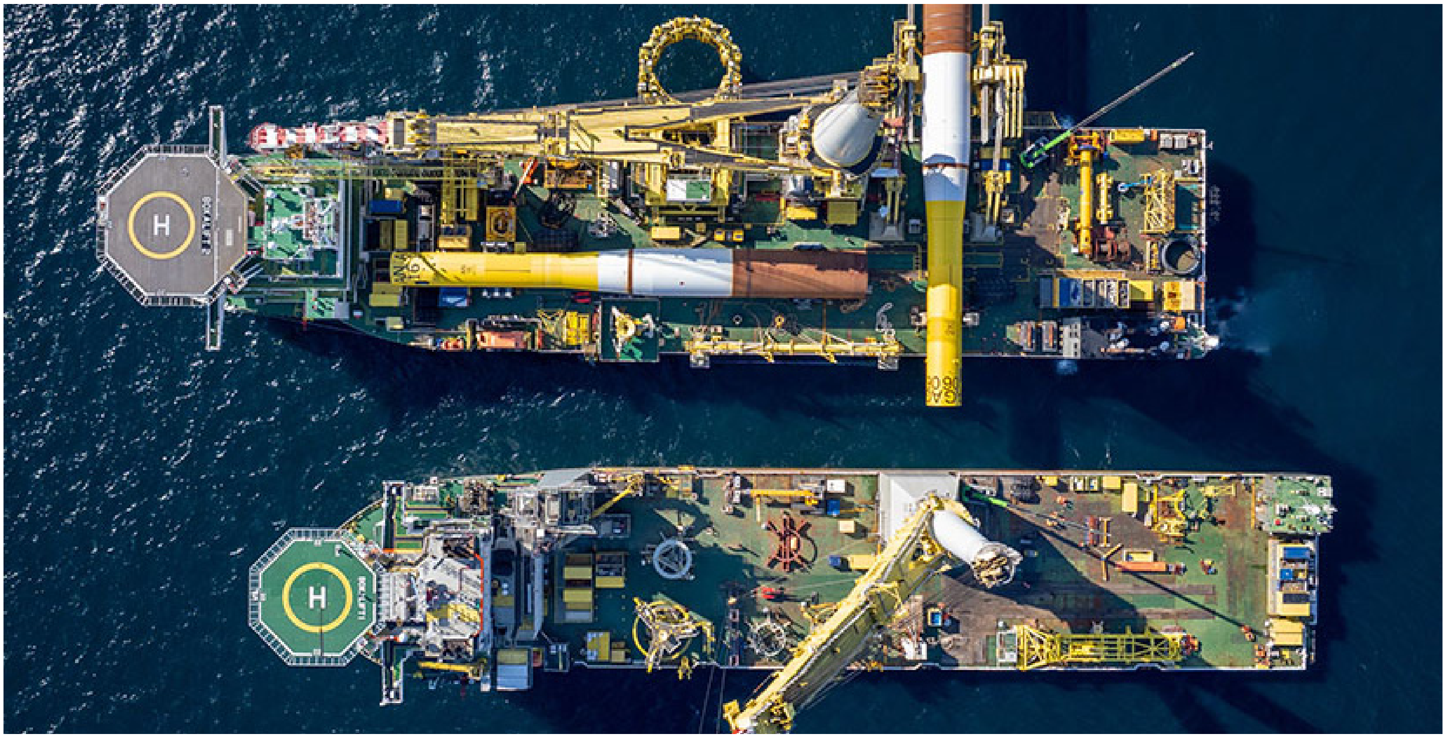
Commissioner Katie Dykes of the Connecticut Department of Energy and Environmental Protection said at a news conference Aug. 25 that Revolution would supply 2.5% of New England's power needs and there is no identified replacement for that power if Revolution is not completed.

ISO-NE said in a news release that delaying Revolution "will increase risks to reliability," and noted that it "is expecting this project to come online, and it is included in our analyses of near-term and future grid reliability."

The RTO said resource development delays "adversely affect New England's economy and industrial growth, including potential future data centers," and implied that the Trump administration's move could discourage future investments in new resources, increasing consumer costs.

While ISO-NE previously said it foresees minimal reliability risks through the end of the decade, it is counting on Revolution to begin providing capacity in 2026.

Revolution has a 150-MW capacity sup-



Installation of wind turbine foundations is shown for the Revolution Wind project in 2024. | *Revolution Wind* ply obligation (CSO) in the winter months of the 2026/27 capacity commitment period (CCP) and a 67-MW CSO in the summer months. For the 2027/28 CCP, the resource's CSOs are set to increase to a 466-MW winter commitment and a 203-MW summer commitment.

For context, to meet NPCC resource adequacy standards, ISO-NE needs 30,305 MW of capacity for the 2026/27 CCP and 30,550 MW of capacity for the 2027/28 CCP.

ISO-NE forecasts reliability risks to increase by the mid-2030s, largely driven by growing demand from electrification, and has emphasized the importance of offshore wind for reducing these risks.

A 2023 ISO-NE study, looking at the year 2032, showed significant winter reliability benefits of offshore wind resources. The study, which assumed 5,600 MW of offshore wind, found that limiting offshore wind development to 1,600 MW increased shortfall in the worst-case winter weather event by up to 193%. Conversely, ISO-NE found that replacing 1,000 MW of fossil resources with offshore wind would reduce shortfall by up to 42%. (See *ISO-NE Study Highlights the Importance of OSW, Nuclear, Stored Fuel*.)

ISO-NE CEO Gordon van Welie, *speaking* before the House Energy and Commerce Committee in March, said ISO-NE studies "have shown substantial reliability benefits of offshore wind, primarily because it delays or displaces the consumption of gas and oil so that it will be more available in the subset of high demand periods when the wind does not blow."

"If the large amount of offshore wind that has been contracted for by the states is significantly delayed or ultimately does not materialize, the region would need to assess the potential impacts and determine what other options might be needed to meet resource adequacy needs in the future," van Welie said.

Varied Reactions

Offshore wind opponents were pleased by the stop-work order, as they were when the Trump administration shut down work on Empire Wind 1 for several weeks starting in April.

On X, Protect Our Coast NJ posted "Bravo!" and ACK4whales posted, "We are hopeful there will be more halt-work orders coming."

The Empire stop-work order cost developer Equinor millions of dollars a day and was widely speculated to be an attempt to twist New York's arm on gas pipeline proposals the state previously had rejected.

The ulterior motive for the Revolution Wind stop-work order, if any, was not clear.

Connecticut Gov. Ned Lamont (D) said he thinks there is a motive, he just does not know what it is.

"I think there's a deal to be had, and I've got to see what the ask is. I knew what it was for [Gov.] Kathy Hochul down in New York," he said at the Aug. 25 news conference. "I think we're going to get this going again."

Lamont said Connecticut already has had productive discussions about increasing the supply of American natural gas and other types of energy in the state.

U.S. Sen. Richard Blumenthal (D), a former U.S. attorney and Connecticut attorney general, said: "This action is nuts, crazy, insane … it is also blatantly illegal."

He said there is reason to believe federal officials broke laws with these actions.

U.S. Sen. Chris Murphy (D) said: "When the oil industry showed up at Mar-a-Lago with a set of demands in exchange for $1 billion of campaign support for Trump, this is what they were asking for: the destruction of clean energy in America."

He added: "This is a story of corruption, plain and simple. President Trump has sold our country out to big corporations with the oil and gas industry at the top of the list."

Other Developments

In other developments Aug. 25:

- Revolution developer Ørsted said it would continue with its plans to raise $9.3 billion, much of that to cover the cost of financing Sunrise Wind, a New York project that potential financing and equity partners shied away from after the Empire Wind stop-work order. The Revolution stop-work order only reinforces the need to raise the funds, the company said.
- Shares of Ørsted stock shed 16.4% of their value to close at their lowest level ever since public trading began in June 2016.
- Ørsted's former development partner, Eversource, saw its stock price close 4.7% lower on investor concerns about the New England utility's exposure to losses on Revolution Wind. When Eversource sold its stock in the project to Global Infrastructure Partners, it guaranteed GIP a rate of return and assumed liability for certain cost increases. (Eversource remains involved in onshore aspects of the project.)
- Ørsted said it will explore all options ranging from expeditious dialogue with permitting agencies to potential legal action.
- Ørsted said investment of about $1.6 billion is needed to complete Revolution Wind; its share is $753 million. It said annual EBITDA on the project once commercial operation begins is estimated at around $160 million. Total investment in Revolution Wind and Ørsted's remaining active U.S. project — Sunrise Wind — is approximately $16 billion.
- New England Power Generators Association President Dan Dolan criticized the stop work order: "Actions like this erode investor confidence and jeopardize long-term electric reliability in the region. … That undermines reliability, raises costs and damages the credibility of our energy markets."
- Rhode Island Gov. Dan McKee (D) said: "At a time when we should be moving forward with solutions for energy, jobs and affordability, this administration is choosing delay and disruption. We are working with our partners in Connecticut to pursue every avenue to reverse this decision. Revolution Wind is key to Rhode Island's economic development, energy security and long-term affordability for our residents."
- North America's Building Trades Unions President Sean McGarvey said: "Let's call the Department of the Interior's stop-work order for Revolution Wind what it is: President Donald Trump just fired 1,000 of our members who had already labored to complete 80% of this major energy project. A 'stop-work order' is the fancy bureaucratic term, but it means one thing: throwing skilled American workers off the job after they've spent a decade training, building and delivering." ■

New England TOs Add 39 New Projects to Asset Condition Forecast

By Jon Lamson

New England transmission owners (TOs) have added 39 new projects in the annual update to the region's asset condition forecast, the companies told the ISO-NE Planning Advisory Committee (PAC) on Aug. 20.

The TOs categorized the projects as either "under development" or "under evaluation." The projects do not yet have cost projections, but most have estimated cost ranges. The TOs forecast 23 projects to cost less than $10 million, nine to cost between $10 million and $25 million, two to cost between $25 million and $100 million, and one to cost more than $100 million.

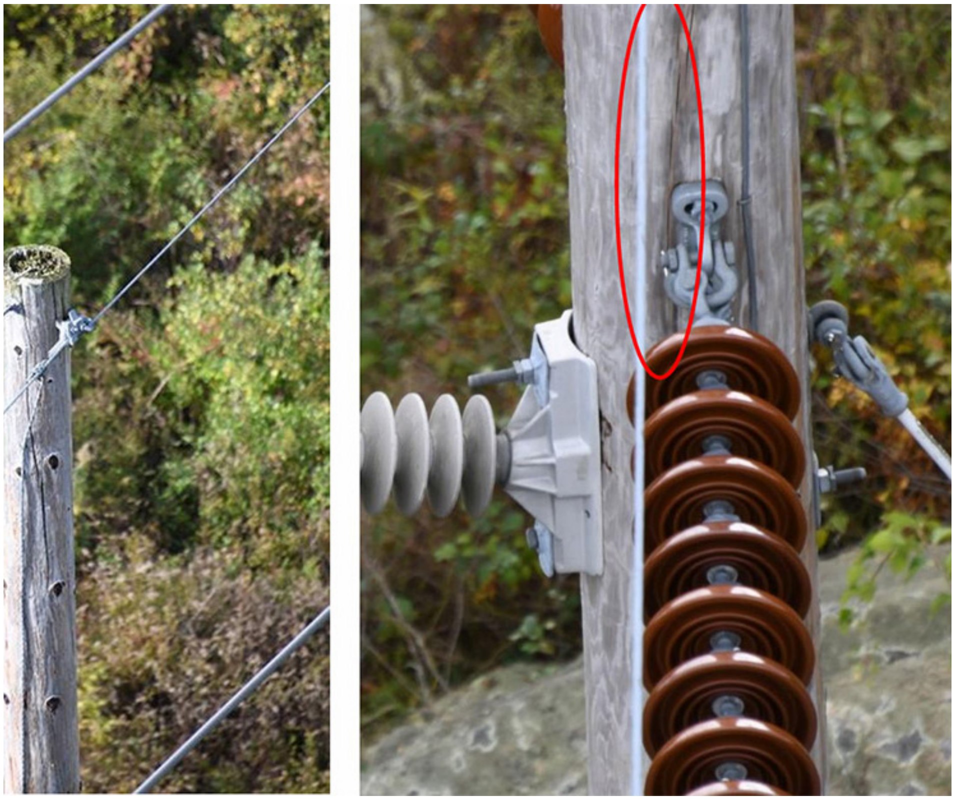
Growing costs associated with asset condition projects have been a major focus of New England states and consumer advocates in recent years. While investor-owned transmission companies have insisted the high costs are necessary to maintain the region's aging grid, states have expressed concern that a lack of oversight and transparency on spending has contributed to higher costs.

According to a June update provided by the TOs, the total estimated cost of in-progress asset condition projects with official price projections is about $5.9 billion. This does not include forecast projects that have only projected cost ranges. (See *New England Transmission Owners Add $95M to Asset Condition List*.)

Earlier in the summer, ISO-NE agreed to take on a non-regulatory "asset condition reviewer" role to help increase transparency into projects. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.) The RTO said in late June it will need about 18 months to develop internal review capabilities but said it plans to hire a consultant to help review the most significant asset condition projects in the interim. (See *NEPOOL PC Briefs: June 24-26, 2025*.)

Why This Matters

Asset condition projects have drawn increased scrutiny from states in recent years as costs have increased.



Deteriorating wood structures on a 115 kV line in Rhode Island | *Rhode Island Energy*

The TOs also have implemented new guidelines around PAC presentations in recent years intended to standardize the presentation format and increase transparency. But PAC presentations remain strictly advisory, and the committee does not have any regulatory authority.

Project Presentations

At the PAC meeting, Chris Soderman of Eversource Energy *presented* an $18 million asset condition project to replace deteriorating wooden structures with steel structures, reinforce overstressed wood structures, and replace Copperweld shield wire with optical ground wire (OPGW) on a 115-kV line in Connecticut.

Soderman said the project would cost about $1.8 million less if the company replaced the shield wire with Alumoweld Static Wire but installing OPGW also would address telecommunication needs.

He also noted that the ISO-NE 2050 Transmission study indicates the line would be overloaded in a 51-GW winter peak scenario and that the upgrades are "setting ourselves up so that when we do look at a reconductor in the future, these structures will be able to handle that."

Carol Burke of Eversource *presented* an update to a substation upgrade project in southern New Hampshire. The project originally was presented to the PAC in 2022 with an estimated cost of about $20 million. Burke said this estimate has increased to $35 million due to an expanded project scope, delayed construction and increased material costs.

Lastly, Kyra Lagunilla of Rhode Island Energy *presented* a $15 million project to replace wooden poles with steel structures and install OPGW and lightning protection on three 115-kV lines. She said the added lightning protection is necessary because the lines do not meet the company's lightning performance standards and lightning has triggered two long-duration outages on the lines since 2011. ■

ISO-NE Proceeding with Shortfall Threshold After Positive Feedback

By Jon Lamson

After receiving positive feedback from stakeholders, ISO-NE plans to proceed with its proposal for a quantitative threshold to determine an acceptable level of energy shortfall risk for the region.

The regional energy shortfall threshold (REST) project is one of the RTO's key initiatives for 2025 and is intended to establish a threshold reflecting "the region's level of risk tolerance with respect to energy shortfall during extreme conditions."

The REST, which incorporates both shortfall magnitude and duration, would be used for seasonal assessments forecasting energy shortfall risks heading into each summer and winter period, along with long-term assessments looking at risks five and 10 years into the future.

When calculating the threshold, ISO-NE would consider the tail 0.25% of 21-day model cases with the most shortfall risk. The REST would be triggered if the average shortfall magnitude of these tail cases exceeds 3% and the shortfall duration exceeds 18 hours. (See "Regional Energy Shortfall Threshold," *NEPOOL Reliability/Transmission Committee Briefs: July 15-16, 2025*.)

Jinye Zhao of ISO-NE said at the NEPOOL Reliability Committee (RC) meeting Aug. 19 that, on average, one of the extreme 21-day cases would occur "approximately once every 90 three-month periods." Accepting this threshold means that "about once every 90 three-month periods, the region can tolerate up to 3% of unserved load on average across the 72 most severe hours."

"Stakeholders have generally expressed support for the ISO's proposed tail α% of 0.25%, proposed shortfall magnitude threshold of 3%, and proposed shortfall duration threshold of 18 hours," Zhao said. "As a result, the ISO has retained its REST proposal as introduced at the June RC."

Zhao clarified that the duration metric will evaluate the cumulative shortfall hours within a 21-day period instead of the longest period of consecutive shortfall hours. She said focusing on consecutive shortfall hours would introduce significant noise to the data, as small gaps between shortfall periods could mask the length of shortfall events.

She noted that ISO-NE never has experienced load shed due to a lack of generation, so it is not possible to back-test these thresholds for accuracy. However, she stressed that the lack of energy shortfall events in the past does not guarantee a risk-free future, and the increasing uncertainties stemming from climate change and a shifting resource mix and load profile could increase risks.

ISO-NE has said the REST will be a key tool to help identify when solutions are needed, but it is "premature to calculate the value of lost load (VOLL)" associated with extreme shortfall periods, Zhao said.

"While there are methodologies available to calculate metrics like VOLL, applying them may be more appropriate if a specific system risk has been identified through the long-term or seasonal assessment process," she said. "A cost/benefit analysis could be helpful at that time to evaluate whether potential risk mitigation options are economically justified once the nature and scale of tail risk are identified and better understood."

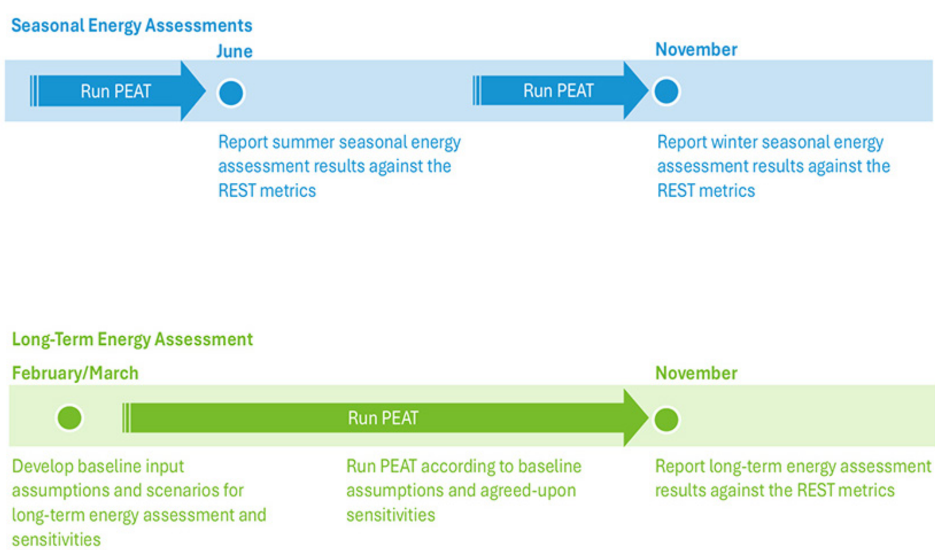
Some stakeholders urged the RTO to start thinking about how to identify and pursue solutions if the REST is violated, noting that, if the region identifies significant risks in one of the initial REST analyses, it likely would take years to establish a process for selecting a solution, work through the process and ultimately develop the selected project.

ISO-NE plans to run the REST analysis in conjunction with its seasonal assessments and will report the summer results in June and the winter results in November. For annual long-term assessments, the RTO plans to begin work in February or March and produce a report in November, beginning in 2026.

Mike Knowland of ISO-NE said the RTO will allow stakeholders to suggest modeling sensitivities to include in REST analyses and that ISO-NE plans to include three to five stakeholder-requested sensitivities in each long-term REST assessment. The RC is scheduled to vote on the REST proposal in September. ■

What's Next

The REST proposal would give ISO-NE another tool for assessing shortfall risks, but it remains to be seen how the region would identify solutions when risks exceed the acceptable threshold.



ISO-NE proposed timeline for seasonal and long-term energy assessments | *ISO-NE*

DOE Orders Mich. Coal Plant to Remain Available Another 90 Days

Consumers Energy had Planned to Retire J.H. Campbell May 31

By John Cropley and Amanda Durish Cook

The U.S. Department of Energy has ordered the J.H. Campbell Generating Plant to remain available another 90 days, saying its capacity is needed to maintain MISO grid reliability.

Consumers Energy had planned to retire the 1,420-MW coal-fired facility in southwest Michigan on May 31, but DOE on May 23 issued an emergency order (*202-25-3*) under Section 202(c) of the Federal Power Act ordering it to remain ready to operate because of a shortage of electricity and capacity to generate electricity. (See *DOE Orders Michigan Coal Plant to Reverse Retirement*.)

That order expired at midnight Eastern time Aug. 21.

Energy Secretary Chris Wright issued the follow-up order (*202-25-7*) at 8:50 p.m. Eastern time Aug. 20; it expires Nov. 19.

In his Aug. 20 order, Wright indicated the generation shortfall in MISO is likely to continue.

President Donald Trump *declared an energy emergency* on his first day in office, and his Cabinet agencies have been scrambling to rejigger energy policy toward the fossil fuels he favors.

One of their stated priorities has been halting retirement of aging fossil-burning plants.

Consumers Energy's J.H. Campbell coal plant | *Newkirk Electric Associates*

Why This Matters

The order is another move by the Trump administration to use aging fossil generation to shore up the grid.

In a news release, Wright cited seasonal outlooks by NERC and NOAA warning of high temperatures in the Midwest as well as resource adequacy projections by MISO itself.

"The United States continues to face an energy emergency, with some regions experiencing more capacity constraints than others. With electricity demand increasing, we must put an end to the dangerous energy subtraction policies embraced by politicians for too long," he said.

"This order will help ensure millions of Americans can continue to access affordable, reliable and secure baseload power regardless of whether the wind is blowing or the sun is shining."

Section 202(c) has been a lightly used provision historically. Just 11 orders were issued during the Biden administration, all of them weather-related. This compares with *nine by Wright since mid-May*, only one of which was weather-related.

The cost of halting the J.H. Campbell retirement has been a point of contention. (See *DOE Extension of Michigan Coal Plant Cost $29M in 1st Month* and *FERC Rules Costs of Mich. Coal Plant Extension Can be Split Among 11 States*.)

It also has been unpopular with environmental advocates.

Sierra Club Beyond Coal Campaign Director Laurie Williams *said Aug. 21*: "By illegally extending this sham emergency order, Donald Trump and Chis Wright are costing hardworking Americans more money every single day for a coal plant that is unnecessary, deadly and extremely expensive."

Earthjustice Senior Attorney Michael Lenoff said: "Chris Wright is not a Soviet-era central planner, but his new order suggests he would fit right in. The order purports to override the considered judgment and careful work of many federal, state and regional bodies who actually have authority to keep the lights on. In their place, Secretary Wright blunders in."

In a statement, MISO said it will "continue coordinating with Consumers Energy to comply with the order."

But MISO again stressed that J.H. Campbell did not clear the planning resource auction and is unnecessary for resource adequacy in the 2025/26 planning year.

"MISO's 2025-2026 Planning Resource Auction indicated adequate resources to meet anticipated demand. State regulators along with utilities have the responsibility of ensuring resource adequacy. MISO remains focused on reliably operating the grid using the resources our members provide, while working closely with stakeholders and regulatory partners, providing visibility into system needs and sending market signals to inform long-term resource planning," MISO spokesperson Brandon Morris said in a statement to *RTO Insider*.

MISO leadership previously has said it might have to navigate similar future orders from the federal government to prop up retiring coal plants.

MISO Director Todd Raba said MISO might have to navigate similar edicts in the future, with about 30 coal plants in the footprint. At MISO's June board meeting, he said it's a "critical topic that will have huge implications in MISO."

Lawmakers, health professionals and other officials *gathered* near the plant in West Olive, Mich., on Aug. 12 to protest its extension. On Aug. 18, a small crowd of community members marched to U.S. Rep. Bill Huizenga's office in nearby Holland, Mich., to again protest continued operations.

Consumers Energy said it was evaluating the order extension and expects to "continue operating the plant as required by DOE."

"We have worked closely with MISO and have been operating in compliance with the order and MISO's dispatch requirements. All power generated by the Campbell plant and other Consumers generating plants is supplied to the MISO grid. Specific details on recent generation are not publicly available at this time," spokesperson Brian Wheeler told *RTO Insider*.

Wheeler also said the utility was "pleased" with FERC's approval of an allocation that's set to disburse cost recovery of the plant among the 11 states or portions of states in MISO Midwest.

Consumers Energy declined to comment on the coal plant's usefulness so far over the summer or how the plant will fit into the MISO market over the fall.

Data from power analytics company Yes Energy shows the 1.42-GW plant has been used consistently since the beginning of August, averaging an 84-88% hourly capacity factor. ■

Federal Volatility, MISO Tx Complaint Rattle Midcontinent Energy Summit

Impact of Trump Administration Energy Policies Takes Center Stage at Infocast Event

By Amanda Durish Cook

INDIANAPOLIS — The tone of Infocast's 2025 Midcontinent Energy Summit was noticeably apprehensive compared with last year, owing to political and regulatory uncertainty, load growth ambiguity, fluctuating tariffs and a pending complaint against MISO's long-range transmission plan.

MISO Senior Vice President Todd Hillman opened the Aug. 19-20 event in Indianapolis by recognizing the unpredictability wrought by ever-changing tariffs, growing data center demand, a rollback of environmental rules and even the surprise move of a Republican president appointing a Democrat to lead FERC.

"We're not sure what 'new normal' is. We're trying to figure that out," Hillman said, speaking for MISO's staff.

Hillman said MISO is trying to "get out of the way" in the rush to bring new data centers online. He noted the footprint could experience load growth of 60% in the next 10-15 years. Currently, almost half the transmission project requests the RTO receives are marked for expedited study treatment and are often meant to serve growing load, he said.

"They're coming, and they're coming fast and furious," Hillman said. "The dog has truly caught the bus."

Notable Quote

"You're going to have to step back from the [federal government] and the executive branch as much as you can and work with the states."

— EDF Renewables Senior Director of Transmission Policy Temujin Roach's advice to developers for the next three years

MISO Senior Vice President Todd Hillman | © *RTO Insider*

Hillman briefly acknowledged the U.S. Department of Energy's order that Consumers Energy delay shutdown of its J.H. Campbell coal plant, saying only that the agency was trying to "help" MISO by mandating the coal plant stay online. (See *DOE Extension of Michigan Coal Plant Cost $29M in 1st Month* and *DOE Orders Mich. Coal Plant to Remain Available Another 90 Days*.)

"We'll see how that plays out," he said, offering no other comment.

Hillman said he wouldn't guess at upcoming actions from the White House.

"Unless we have a cocktail break in the morning, I'm not going to go there," Hillman joked.

He similarly refused to take a stab at potential next moves from Congress.

"Again, not enough beer in the bar," he joked.

However, after being asked by the audience, Hillman said President Donald Trump's One Big Beautiful Bill Act is likely to impact the 171 GW of generation interconnection requests MISO fielded in 2022. The record-breaking surge of applicants was almost exclusively composed of renewable energy and battery storage projects.

"I don't know yet, but anecdotally, I think it will be significant," Hillman said of the impact.

Hillman also promised MISO "will get better" and create more viable market participation rules for energy storage.

The RTO's generator interconnection queue totals about 300 GW. Another 59 GW of projects have approvals to interconnect but are experiencing construction delays.

DOE Intervention and Load Growth

Brad Pope, director of legal and regulatory affairs at the Organization of MISO States, said the DOE's involvement in fossil fuel plant retirements is "certainly a new element we're grappling with."

Pope pointed out that J.H. Campbell's retirement was comprehensively examined before it was announced. He added that the $29 million bill the plant accumulated over its first 38 days of extended operations makes customer affordability a challenge.

"This isn't just something that's a local impact," Pope said. He noted FERC's decision that the cost of keeping the plant online be spread across all MISO Midwest participants means other states have no control over incurring costs.

However, Pope said "there's a whole host" of new technologies, including HVDC lines and grid-enhancing technologies, and new procedures — including MISO's expedited queue lane — that state regulators are also fitting into the RTO's tapestry.

Illinois Commerce Commissioner Stacey Paradis said Illinois is concerned about how OBBBA could affect the goals of the state's Climate and Equitable Jobs Act (CEJA). She said that so far, Illinois is lagging in reaching its 40% renewable target by 2030, and the state may open a new long-term procurement plan to secure more solar. Paradis added that the federal pullback of incentives for clean energy should make the next few years "interesting."

Paradis noted that DOE hasn't yet moved to keep plants on in Illinois and derail CEJA's mandate that coal and gas generating units achieve zero emissions or close by the end of 2045 at the latest.

Paradis said non-disclosure agreements from data center developers are a stumbling block to efficient planning for regulators, utilities and RTOs. She said it's a safe bet that if a data center is engaging Illinois about accommodating its load, chances are it's also holding conversations with Wisconsin, Indiana, Michigan or even Missouri.

In some cases, non-refundable deposits of a few million dollars aren't enough to deter developers from simultaneously courting multiple locations for a single project, she said.

"For some of them, that's not even pennies on the dollar," Paradis said. "We don't want to overbuild. We don't want to burden our customers with billions. We need to figure out what's real."

Indiana Utility Regulatory Commissioner Sarah Freeman said load growth projections have come into sharper focus compared with 18-24 months ago.

"They're still not on a level to which I would risk the pocketbooks of my ratepayers, my fellow Hoosiers," Freeman said. "The speed at which everything is moving does increase the risk of stranded assets."

"Utility commissioners are risk managers," Pope said, adding that the "truth is somewhere in the middle" for recent load forecasts.

'Chaos'

Other panelists said OBBBA has introduced unprecedented uncertainty in the developer space.

"It's chaos right now," EDF Renewables Senior Director of Transmission Policy Temujin Roach said of today's political climate. "We need to know what the hurdles are going to be. … You're going to have to step back from the [federal government] and the executive branch as much as you can and work with the states."

Roach advised renewable developers to employ that tactic for the three-year remainder of the current presidential administration, or however long it lasts.

He said generation developers are in a new environment where they must be more circumspect when submitting projects for interconnection study.

"We have to have quality and confidence in our projects. You can't do the 'spray and pray' process we did for a while," Roach said. "Are we still going to lose some projects? Sure."

Roach said MISO's 59 GW of incomplete generation is often "thrown in developers' faces." He acknowledged that developers weren't as disciplined a few years ago and said interconnection procedures were likely too lenient to discourage speculation.

Roach noted also that the industry must do all it possibly can to increase use of energy storage, demand response and grid-enhancing technologies. He said grid planners cannot continue with no end in sight to prescribe billions of dollars of lines. At some point, he said, consumers will be unable to shoulder the costs.

"We're going to have to explain how we're being efficient with billions and billions of dollars," he said.

Developers Back MISO Long-range Tx

However, Roach said the energy industry throughout the Midwest is relying on MISO's $22 billion second package of long-range transmission lines to manage load growth and accommodate future generation plans. He said there comes a point where stakeholders should consider the transmission portfolio finished and move forward, referring to the recent five-state complaint at FERC. (See *Five Republican States File FERC Complaint to Undercut $22B MISO Long-range Tx Plan*.)

"It just turns into a death spiral of restudies. If we keep looking backwards and keep restudying, we'll never move forward. Hopefully, FERC sees it that

From left: Indiana regulator Sarah Freeman, Illinois regulator Stacey Paradis and Organization of MISO States' Brad Pope | © *RTO Insider* way," Roach said. He added that stakeholders can always advocate for changes on the next MISO planning exercise.

"Yes, transmission is useful. I have no other comment. Ask me again in a year," Robert Frank, a utility financial analyst at the North Dakota Public Service Commission, said dryly.

The North Dakota commission spearheaded the complaint against MISO's second long-term portfolio.

Multiple developers said MISO's long-range transmission planning makes the footprint more attractive for project development.

Anthony Doering, a senior director of interconnection and transmission at independent power developer MN8, said generation developers are working their hardest to bring the most viable projects forward. But developers are reliant on MISO, regulators and transmission companies to get the long-range transmission built on time, he said.

David Ticknor, senior interconnection engineer at RES Group, said MISO's second long-range transmission portfolio is poised to support load additions, fleet change and reliability. He said it's difficult to quantify reliability benefits of transmission, but MISO did a commendable job in its benefits analysis.

"I think it's one of the coolest transmission buildouts we've seen in a long time," Ticknor said.

However, Ticknor said his company is

David Ticknor, RES Group | © *RTO Insider*

Jim Marett, Swift Current Energy | © *RTO Insider*

keeping a "keen eye" on the recently filed complaint from the five states against the portfolio.

"The cost allocation point is what it always comes down to," he said, adding that MISO did a good job of planning despite not being able to solve all issues on the grid with a single transmission package.

Doering advised RTOs not to "cost-allocate the generators for your backbone transmission projects." He said it's difficult to get companies to sign on to power purchase agreements when potential generation projects are expected to entirely cover the cost of large transmission, with costs not commensurate with use.

"The need [for transmission] is already established. We don't need to punish generators. We need to allocate the marginal impact of their use of the facility," Doering said.

Ruchi Singh, vice president of interconnection and transmission at Brookfield's Urban Grid, said if MISO planned transmission to increase capacity along the Midwest-South transfer constraint, it would open several possibilities to generation developers.

Swift Current Energy senior vice president Jim Marett said MISO is the easiest RTO to interconnect into today. He said although it's slow and expensive, the MISO queue doesn't experience the "sudden stops" that occur in other RTOs.

Development Becomes Trickier

"Development hasn't been easy in the past year or so," conceded Erik Ejups, director of power marketing at EDF Renewables. He said it's become easy for a "small opposition group" to have an outsized impact on a solar project's chances.

Foss and Co.'s Dawn Lima said OBBBA has set off a growing perceived risk from investors, who now request grandfathered projects whose construction started in 2024 and will be complete around 2026 or 2027.

Marett said there are enough renewable projects in the beginning stages or that will kick off physical construction before Sept. 2 (a federal deadline for wind and solar projects that plan to use the 5% safe harbor rule for claiming tax credits) to keep developers busy for the next few years and act as a *de facto* grace period for absent incentives. But he said growing capex costs will likely eat into developers' margins. Fortunately, Marett said, data centers seem to have an appetite for new generation, even if it's more

EDF Renewables' Temujin Roach (left) and Ameren's Justin Stewart | © *RTO Insider* expensive.

"What we've noticed is that an upgrade cost that would have gotten a project thrown out of the pipeline in 2017, we're now ecstatic about. It's a little bit more of a high-stakes poker game," he said.

Conductor Solar CEO Marc Palmer said solar, storage and distributed energy resources "particularly got a gut punch" with the federal phaseout of incentives.

Palmer predicted that the remainder of 2025 and 2026 will contain strong construction trends, with a dip over 2027, followed by a recovery as costs of the assets naturally drop.

"We expect that to start bouncing back in time without any additional policy changes," Palmer said. "We think the next 10 years are going to [see a] transition to value-driven growth, which is going to lead to a healthier market overall."

Nick Panko, vice president of tax compliance firm CFO Services, said he expects the "emotional response" to the bill to wane.

"Every four years, you're used to the swing," agreed Brad Tyson, a vice president at Santander. Tyson said recent IRS guidance that laid out the transition in tax credits was a "small win" for renewable developers. He said some developers who braced for a tight, two-year shift breathed a sigh of relief when they found there would be a pathway to four-year safe harbor provisions. (See *IRS Guidance on Wind and Solar Credits Not as Bad as Feared*.)

Under OBBBA, wind and solar projects can qualify for the phased-out clean energy production tax credit and clean energy investment tax credit if they are placed in service by the end of 2027 or begin construction before July 4, 2026.


Nick Panko, CFO Services | © *RTO Insider*

Panko said by the 2027 deadline, the U.S. will then gear up for another tax policy shift under a new presidential administration.

Cons Before Pros

John Davies, CEO of the eponymous public persuasion firm Davies, said this moment embodies the Chinese curse — not a proverb, he stressed — "May you live in interesting times." He said for many, it's challenging and for some, it's a crisis.

"We look at this time as an opportunity for good companies, good players to make advances," Davies said.

Davies said renewable projects, which often enjoy massive public support, fail because companies neglect to engage properly with the public. Davies said it may seem counterintuitive, but project developers should acknowledge the cons of a project before publicizing the pros to build credibility.

"If you can acknowledge, then contrast, you're going to win every time," he said.

Davies said currently, wind developers have the biggest perception problem, with more negative online articles available than positive.

"They have given up the web," Davies said.

Davies said the people who have a "not in my backyard" attitude are either rational, irrational, or fearful of unknowns of the infrastructure or potentially being disrespected.

"They decide to be crazy because that's what their political party tells them to do," Davies said of the irrational types. He advised companies to listen to communities, perform outreach and cultivate relationships.

Davies advised against developers creating a social media page for projects, saying it's a surefire way to create a hot spot for protesters. He joked that Mark Zuckerberg's office contains a graveyard of renewable energy projects.

Brian Ross, vice president of renewable energy at Great Plains Institute, said every community should consider itself a "host" community for clean energy.


Brian Ross, Great Plains Institute | © *RTO Insider*

He said the clear delineation that once existed between host communities and strictly consumer areas is evaporating. Every community contains the potential for solar energy, he said.

Ross said GPI is conducting campaigns where the nonprofit approaches municipalities to "soften the ground" and ask residents what they want from inevitable renewable projects versus what they dislike about them.

"Once you get them talking about what they want, the objections start to diminish," Ross said. He said community members begin to associate projects with funding for local programs rather than usurping farmland.

Ross said developers might have to contend with lingering mistrust because developers previously publicized a project in a community, then vanished without explanation when upgrade costs jumped too high. He said those kinds of gaps are common in a "capitalistic landscape."

Ross also said GPI as a rule doesn't mention that a particular project will help alleviate climate change unless the community already has established climate goals. He said many communities view the "clean energy economy as thrust upon them."

Hillman said, at the end of the day, the industry's end goal is reliability. He said industry players need to have "elevated debates" in an era of "I'm right, you're wrong."

"Use phrases like, 'Tell me more;' 'What's your perspective?' Or 'While I don't quite see it that way, I can understand where you're coming from,'" Hillman urged. ■

Louisiana PSC Approves 3 Controversial Gas Plants Ahead of Schedule for Meta Data Center

By Amanda Durish Cook

The Louisiana Public Service Commission voted two months earlier than initially planned to approve 2.3 GW in new Entergy gas plants to supply a new, $10 billion Meta data center.

The PSC voted 4-1 to allow Entergy to build three gas generators to power the Meta facility at a cost of $3.2 billion, drawing boos from the audience at the Aug. 20 meeting. (See *Entergy La. Confirms Meta Data Center Behind 3 Proposed Gas Plants*.) Entergy requested the early vote.

Larry Hand, Entergy Louisiana's vice president of regulatory and public affairs, said the electric service agreement for the next 15 years ensures Meta will pay to cover the new generation costs, mitigating impacts on other customers.

"Entergy's goal, and I believe I can safely speak for Meta, was not to come to Louisiana and cause costs to be shifted to other customers," Hand said. He said while Entergy took pains to strike the most sensible deal it could, there nonetheless would be risks associated with the project.

"It's a 15-year deal, so we can't predict everything," he said.

The Bottom Line

A 4-1 vote from Louisiana regulators means Entergy Louisiana is cleared to build a trio of gas plants to serve a $10 billion Meta data center without a competitive bid process.

Hand estimated that net ratepayer impacts will be "plus or minus a dollar" per month. He also said if Meta doesn't renew the contract after the first 15 years, then the MISO South region will have "a gift" of half-paid-for, relatively new gas plants among the region's other aging thermal plants in 2041.

According to the contract, should Meta exit the contract early, the generating assets would become wholly owned by Entergy. Louisiana PSC staff said while Meta's abandonment of the project is a remote possibility, Meta likely would have paid for the most expensive start-up years of the project by the time it leaves.

Hand said it was necessary for Entergy to circumvent commission procedure — forgoing conducting a request for bids on the plants — and self-build the generation to meet Meta's aggressive timeline. He said opening an RFP would have added a second year to the project.


The Louisiana Public Service Commission on Aug. 20 in Plaquemine, La. | *Louisiana PSC*

Entergy Louisiana ratepayers are set to cover an additional $550 million in transmission costs that are necessary to connect the data center's generation to the grid.

Hand acknowledged not all who protested the deal agreed with the final, settled version of the contract. Louisiana PSC staff, Entergy, Sierra Club and the Southern Renewable Energy Association signed off on the settlement deal.

The finalized deal contains more consumer protection, including a provision that Meta's minimum bill payments would cover 100% of the costs of the trio of generating units, including cost overruns. Meta also agreed to fund development of 1.5 GW of solar generation under the state's Geaux Zero program and to provide up to $1 million per year for Entergy's Power to Care, which is a bill assistance program for low-income, elderly and disabled Entergy Louisiana customers.

Meta, which has a goal to be carbon neutral by 2030 both in operations and suppliers, also expressed a willingness in a separate corporate sustainability rider to help fund carbon capture and sequestration at Entergy's existing Lake Charles Power Station.

Entergy plans to submit the gas plants to MISO's newly approved expedited interconnection queue. Hand said it wasn't efficient to try to build the generation behind the meter, noting that the data center likely would need twice as much generation as planned to run at a more than 99.9% load factor behind the meter.

The data center is slated for a 2,250-acre state-owned site known as Franklin Farms. Two of the new gas plants will be named after Franklin Farms.

Commissioner Eric Skrmetta called the deal groundbreaking because Entergy found a way not to burden the public with new generation builds. He said the contract "sets a new standard to develop power resources to the advantage of our ratepayers."

Davante Lewis — who provided the sole "no" vote — said he liked the contract's strong consumer protection and Meta's assistance with solar expansion but said he ultimately struggled with Entergy's claim that it needed to bypass a competitive bid process and self-build generation.

"The truth is there are a lot of things that I just cannot verify at this moment," Lewis said. "I cannot say with enough certainty that this deal and its power agreement serves the greater good, has the public in interest, with the least-cost revenue."

Lewis said he hoped that future deals with data center hyperscalers contain competitive bidding, battery storage, possibly flexible load provisions and "a full suite of front-end customer protections."

Commissioner Foster Campbell, whose northeast Louisiana district will host the plants, said the development was something his community was "waiting a long, long time for." Campbell said he had been "pulling for jobs" in those poverty-stricken parishes for more than 50 years. Campbell said he was supporting the project despite being a Democrat. He explained that it's easier to be against everything than support something.

"This is something we drastically need in North Louisiana; it's a shot in the arm," he said, noting the area was hemorrhaging residents to Dallas, Houston, Baton Rouge and New Orleans.

Campbell also said there's no such thing as a "bulletproof" contract.

Residents at the meeting voiced concerns ranging from Meta's potentially massive water use, the lack of permanent jobs created by the facility and doubts that Entergy wouldn't raise rates because of the project. A few said they considered the project speculative because no one knows how AI would function in 15 years. Multiple residents asked the commission to consider delaying their vote.

Logan Burke, executive director of the Alliance for Affordable Energy, told the commission there are many people living in Louisiana who "cannot handle another dollar on their bill." She said she was concerned the contract could shift costs and risks onto ratepayers. Burke said ratepayers would foot maintenance costs of the plants, which are poised to deepen the state's overdependence on gas.

The Union of Concerned Scientists *said* the vote was rushed. The organization said the project would further tax Louisiana's grid, which is considered unreliable when compared to other states because of its shortage of transmission capacity, an overreliance on methane gas and the state's commonplace extreme weather.

"Observers inside and outside the state have undoubtedly taken notice of this pattern of fast-tracking utility proposals with very little public notice and transparency for the residents most impacted," UCS energy analyst Paul Arbaje said in a statement.

Entergy Sticks by Gas Choice

At the Aug. 19 Midcontinent Energy Summit in Indianapolis, Kurt Allen, director of industrial accounts at Entergy, said the utility is trying to build generation "as fast as they want it."

Allen said developing renewable energy to meet large load customers remains difficult for Entergy.

"The price is not really coming down on those. There's a challenge there, and I think it's going to be a challenge for the next several years," Allen said. He said it's tough to convince large customers to pay the resulting prices from Entergy's requests for proposals on renewable energy. He also expressed doubt over Entergy's ability to install carbon-capture technology.

Allen said the Meta project is labor-intensive and getting the three generating units and associated transmission built fast enough for Meta's timeline will be challenging. He said Meta representatives commended Entergy on its swiftness in assembling the deal.

Despite the Meta's Louisiana plans relying on natural gas, Allen predicted decarbonization likely will be driven by hyperscalers that have the money and the will.

Allen declined to answer an audience question on whether Entergy is thinking about how to bring down the costs of network upgrades so it's more cost-effective for renewables to connect in MISO South.

At the same event, Entergy's Wyatt Ellertson said the utility believes natural gas generation is the most reasonable solution for high-load factor customers. ■

NextEra Closer to Recommissioning Duane Arnold with FERC Waivers

Ruling Means Nuclear Plant Could Reopen as Early as 2028

By Amanda Durish Cook

FERC on Aug. 25 granted NextEra Energy's request to waive certain rules under MISO's tariff to allow the company to restart its Duane Arnold nuclear plant by the end of 2029.

The commission ruled that NextEra is free to combine interconnection service and alter a point of interconnection, bringing the company a step closer to recommissioning the 50-year-old Duane Arnold Energy Center in Palo, Iowa (*ER25-2989*).

NextEra is in the process of reinstating the plant's operating license with the Nuclear Regulatory Commission and claims it could resume commercial operation on the plant by the end of 2028 at the earliest and the end of 2029 at the latest.

In its Aug. 25 order, FERC permitted NextEra to combine leftover interconnection service at the site and use a nearby standalone interconnection agreement from a NextEra affiliate company to accommodate Duane Arnold's historical peak winter net capacity range of 600-619 MW.

The commission also allowed NextEra to use MISO's generator replacement process to support recommissioning, even though an affiliate company — and not NextEra itself, the historical owner — is heading recommissioning efforts and cannot meet the original commercial operation deadlines of the stitched-together interconnection services.

The Duane Arnold plant was idled in August 2020 after a derecho damaged the plant's cooling towers and Alliant Energy ended its power purchase agreement five years ahead of schedule. NextEra subsidiaries quartered Duane Arnold's

Duane Arnold Energy Center | *NextEra Energy*

interconnection service among four planned solar farms, only one of which was constructed and sold. The three remaining solar generator interconnection agreements are set to be bundled with NextEra affiliate Kinsella Energy Center's 200-MW interconnection service to support the nuclear plant's re-entry on the grid. NextEra plans to consolidate the interconnection service at the 161-kV level.

NextEra said equipment necessary to repower the plant, including generator step-up transformers, isn't scheduled to arrive until 2028, making the 2026 commercial operation target of the trio of original solar plans infeasible. The plant's boiling water reactor is currently in long-term storage after being de-fueled.

'Old-fashioned Way'

In its order, FERC also accepted NextEra's request for a Dec. 31, 2029, commercial operation deadline and agreed with the company that a late 2029 restart date would allow for "unexpected delays resulting from challenges driven by the complexity of a project of this nature including parallel supply chain activities, physical site work and regulatory processes that will be required to return the plant to power operations."

NextEra said it and MISO agreed that a change to the point of interconnection would have "no material adverse impacts" on the grid or other interconnection customers.

NextEra said without waivers of MISO's interconnection rules, it could have been forced to start fresh and apply to enter the RTO's interconnection queue, which could add years to the restart goal.

FERC said NextEra "acted in good faith in investing significant capital and securing interconnection rights in order to pursue a consolidated [generator interconnection agreement] necessary to recommission Duane Arnold." NextEra said it could invest anywhere from $50 to $100 million over 2025 to fire up the plant within three to four years.

The commission said without the waivers, MISO would have been forced to

What's Next

NextEra will combine three existing generation interconnection agreements to make a Frankenstein's monster of interconnection service in another step to reopening the Duane Arnold nuclear power plant in Iowa.

terminate the existing interconnection rights that Duane Arnold is counting on to reconnect. It said granting extra time would give NextEra the space to "obtain regulatory approvals, procure necessary equipment and recommission Duane Arnold."

Pamela Mackey Taylor, director of the Iowa Chapter of the Sierra Club, protested the waivers and said they weren't necessary because they weren't caused by unforeseen circumstances. Taylor argued also that the nuclear restart would lead to the abandonment of about 600 MW of solar development, making impacts more pronounced than NextEra claimed. Finally, she said NextEra has no guarantee from the NRC that Duane Arnold can reopen.

NextEra said data centers' need for high-capacity baseload generation led it to alter its solar power plans at the nuclear site.

FERC said it wasn't presented evidence that the solar projects will be "wholly abandoned." The commission also said it would not opine on NextEra's proceeding at the NRC.

Speaking at Infocast's 2025 Midcontinent Energy Summit on Aug. 19, MISO Senior Vice President Todd Hillman said nuclear power could play a bigger role in the RTO.

"In MISO, we're just doing it the old-fashioned way. We're turning on old stuff," Hillman joked, referencing nuclear power plant restarts at Palisades in Michigan and Duane Arnold in Iowa. ■

NYISO Unveils Changes to Demand Curve

ISO Explains Reasons for Dropping Seasonal CAFs

By Vincent Gabrielle

NYISO has *proposed* to stop using "winter to summer" and "summer to winter" ratios to determine maximum clearing and reference point prices in its seasonal demand curves.

Their use is no longer necessary for the demand curves because NYISO is developing distinct seasonal minimum installed capacity requirements, ISO staff says.

"If NYISO were to move to the seasonal requirement structure without removing these availability adjustments, the seasonal [installed capacity] ICAP demand curves would be adjusted for seasonal differences twice," Alexis Drake, a NYISO senior market design specialist, said during an Aug. 19 meeting of the ISO's ICAP Working Group.

The two ratios are adjustments to seasonal capacity availability the ISO uses to account for seasonal differences in ICAP availability on the spot market.

During the last demand curve reset, the ISO looked into using seasonal ICAP demand curves to reflect differences in winter/summer reliability risk. During the current capability year (2025/26), NYISO used the ratios to calculate separate demand curves for each season.

Drake said that method more accurately reflects future New York grid needs in upcoming spot market auctions.

What Happened to Seasonal CAFs?

In a previous meeting, the ISO unexpectedly *dropped* seasonal capacity accreditation factors (CAFs) from its winter reliability enhancements project. (See *NYISO Drops Seasonal CAFs from Winter Reliability Project*.) Stakeholders had asked the ISO to walk through its internal analysis and discussions of seasonal CAFs.

Astoria Generating Station in Queens | *Ben Schumin, CC BY-SA-2.0, via Wikimedia*

"This presentation is about correcting that oversight," said Mike Swider, NYISO capacity and new resource integration market designer.

CAFs represent the marginal reliability contribution of resources in the ICAP market counted toward New York State Reliability Council resource adequacy requirements. None of the calculations on the ISO or NYSRC end incorporate seasonality. The Installed Reserve Margin and the Locational Minimum Installed Capacity Requirement cases represent reliability risk annually across both seasons. Annual CAFs are calculated using the final, annual LCR case.

Swider said there is no "stable criteria" to calculate marginal reliability values for each season. Using the installed reserve margin as the ultimate basis for modeling seasonal reliability risks creating situations where certain resource classes have no, or almost no, CAF value.

"If there is only summer risk, some resources, even the perfect resources conceptually, receive zero CAF value in the winter," Swider said. "We have concern about large resources entering and exiting and changing the seasonal risk from year to year and the volatility that's entailed."

A resource that isn't compensated for its capacity contribution might pull out of the market, introducing reliability risks even in months — such as November — where those risks aren't ordinarily forecasted.

Swider said the ISO also looked into using weighted CAFs using seasonal CAF values and attribute payments to potentially mitigate these issues. He said there was "no basis" for setting weights and no "clear cost basis" for attribute payments as a service.

In response to a stakeholder question about whether NYISO had examined what other RTOs do with respect to seasonal values, Swider said the ISO had looked at MISO and SPP's processes.

"[MISO] had to do some interesting gymnastics to calculate seasonal CAFs," Swider said. "In the end it wasn't useful for us."

Swider said another issue is that, unlike other RTOs, NYISO does not select its own reliability criteria, a task that falls to the NYSRC. Even if the ISO was able to pick its own reliability criteria, its winter risk modeling wouldn't need to adopt MISO's modeling techniques, he said, because MISO is modeling a lot of terrestrial wind, for example — a resource not prevalent in New York.

The ISO also went over tariff and manual revisions, respectively, for the *Firm Fuel* project and for *Certain New Resource Entry*, the latter intended to handle the Champlain Hudson Power Express. ■

Why This Matters

The demand curve sets prices for capacity every four years. Recently the ISO has been experimenting with seasonal demand curves to reflect seasonal risks.

PJM Stakeholders Reject Proposals to Rework Accreditation

By Devin Leith-Yessian

The Markets and Reliability Committee rejected three proposals to revise aspects of PJM's effective load-carrying capability (ELCC) accreditation model, which has been criticized as opaque and lacking incentives for resource owners to invest in boosting performance.

The PJM *proposal*, which received 30.7% sector-weighted support, would introduce a "forgetting factor" to weigh resource performance during more recent performance assessment intervals (PAIs) more heavily. The RTO said that would allow modeling to more quickly reflect improvements made to units without fully erasing historic data or relying on counterfactuals. It also would align the days performance is drawn from with the respective weather and load scenarios, establish winter capacity ratings and produce detailed documentation on how the ELCC model functions.

When building load models for future delivery years, the historic weather data is shifted six days backward and forward to develop 13 scenarios for each year back to the 1993/94 delivery year. PJM's Pat Bruno walked the committee through an example where the analysis for Aug. 9, 2026, would draw weather data from each year between 1994/95 and 2024/25, with each year including data from Aug. 3 through Aug. 15. He said those extra days effectively have downplayed the correlation between resource performance, weather and load.

The winter capability portion of the proposal would create parallel installed capacity (ICAP) and capacity interconnection rights (CIRs) for the winter by analyzing how resource outages and capability differ with ambient conditions and how that output is deliverable during those months. Resources with capacity commitments would see their energy market must-offer requirements and seasonal capability tests based on their winter ICAP rating.

Why This Matters

Stakeholder perspectives on PJM's proposal were mixed, with many arguing there is not sufficient understanding of how ELCC functions nor the outcomes the proposed changes might have.

Several generation owners argued that including higher winter ratings when determining the output a resource is expected to be able to provide during a PAI could result in units with higher capability in the winter being penalized for not being able to match that performance during a summer event.

Bruno said annual ratings are meant to reflect possible output across all risk hours in a delivery year, including periods where a resource is expected to over- and under-perform. He compared it to the accreditation for solar resources including the possibility of a PAI occurring during the night. He said the incremental winter capability would add a significant amount of supply to the 2028/29 Base Residual Auction (BRA), between 800 MW to 1 GW, largely by improving the capability of wind resources.

Sensitivity analysis PJM ran on its proposal using the 2026/27 auction as a base case found that the alignment of the weather rotation data would increase the installed reserve margin (IRM) by 3.3%, shift seasonal loss of load hours (LOLH) toward the winter by 18% and reduce the unforced capacity (UCAP) margin by 4 GW. Winter ratings would decrease the IRM by 1.1%, reduce the winter share of LOLH by a third and increase the UCAP margin by 1.8 GW. The performance weighting factor would have minimal impact on the IRM, while increasing the winter LOLH by 4%.

Stakeholder perspectives on the proposal were mixed, with many arguing there is not sufficient understanding of how ELCC functions nor the outcomes the proposed changes might have. Consumer advocates and some generation owners also said it overstates weather and correlated outage risks. Supporters said it is not a panacea for their concerns with ELCC, but one step toward improving the paradigm. It *received* the strongest support from the other suppliers sector, at 54.5% voting to endorse, followed by generation owners at 45.8%, transmission owners at 42.9%, end-use customers at 5.9% and electric distributors at 4.2%.


PJM's Pat Bruno | © RTO Insider

Paul Sotkiewicz, president of E-Cubed Policy Associates, said he doesn't believe there's sufficient transparency on the functioning of the ELCC modeling to vote on changes to its methodology, noting the Board of Managers has directed PJM to bring on a consultant to review ELCC and "identify additional recommended enhancements." He said the 0.2 value for the exponential smoothing used in the performance weighting is arbitrary and the proposal overall aims to address correlated outage risks he does not believe exist. (See "Board Overrides Stakeholder Rejection of Auction Parameters, Directs Hiring of Consultant," *PJM Board Initiates CIFP Addressing RA, Large Loads*.)

Gregory Pakela, manager of regulatory affairs for DTE Energy Trading, said the RTO's proposal ignores changes PJM has made in its operating procedures that have had a significant impact on resource performance and system risks, namely the addition of capacity performance (CP) and advance commitments through conservative operations. While the correlated outage risks may continue to exist with gas generation, he said that should be further investigated through a study before making market changes.

James Wilson, a consultant for several consumer advocates, said the aligning of weather and performance days further exacerbates overstated extreme weather risks caused by outlier data associated with winter storms in January 1994.

Dominion's Jim Davis said the proposal provides a reasonable incremental improvement to ELCC and asked that PJM continue pursuing transparency improvements allowing resource owners to verify their accreditation regardless of the outcome of the MRC's endorsement.

"We shouldn't let the perfect be the enemy of the good here," he said.

LS Power's Tom Hoatson said the company has had success replicating the ELCC modeling and managed to produce results similar to PJM's, making the methodology less of a black box. While there are additional improvements the RTO can make to ELCC, he said the proposal would be an improvement, particularly the winter CIR component.

ODEC Proposes to Reduce Winter Storm Elliott and Polar Vortex Weighting

The Old Dominion Electric Cooperative (ODEC) offered an alternative adopting the changes in PJM's proposal and reducing the probability of the Monte Carlo simulation built into the ELCC model selecting performance data from the December 2022 Winter Storm Elliott or the 2014 polar vortex by 33%. The proposal received 63% sector-weighted support, with electric distributors unanimous in their endorsement, 94.1% of end-use customers in support, 58.3% of other suppliers, 37.5% of transmission owners and a quarter of generation owners.

Reducing the weight of those storms aims to reflect that PJM has made changes to its operations around winter storms which reduce the likelihood of the poor performance seen during those events from recurring, ODEC's Mike Cocco said, pointing to the addition of CP and conservative operations. Including the data from those storms without some acknowledgment of the changes PJM has made would result in overly conservative accreditation and create a paper capacity shortage on top of a burgeoning actual shortage.

He compared the 24% forced outage rate during Elliott with the 9% outage rate

Monitoring Analytics President Joe Bowring | © *RTO Insider*

observed during the 2025 Martin Luther King Day storm. Both events had similar weather patterns and occurred during a holiday weekend, periods where gas procurement has proved challenging, but the latter saw a 63% lower forced outage rate he attributed to advance resource commitments PJM secured through the conservative operations protocol.

PJM Senior Vice President of Operations Mike Bryson said the RTO engaged in a lot of review after Elliott and made operations improvements but can't quantify those impacts.

Pakela argued that PJM's proposal ostensibly appears more sophisticated than ODEC's, but the same results could be reached by changing the arbitrary 0.2 exponential smoothing value. While PJM has pushed back on approaches that would rebalance the winter-skewed risk modeling toward the summer, he said there have been several pre-emergency operations declarations, shortage pricing events and load management deployments in summer 2025.

Even though there have not been any PAIs, there were reserve shortage events not captured in the ELCC modeling which he says support a shift toward summer risk, particularly given the growing concerns around large load growth pushing summer peaks higher.

PJM Vice President of Market Design and Economics Adam Keech said while there may be more summer capacity deployments, the magnitude and duration of winter events tens to be much greater.

Monitor Proposes Alternative Approach to ELCC

A proposal from the Independent Market Monitor would jettison all elements of PJM's proposal and replace it with three components: remove all unit performance data from Elliott and the polar vortex from the ELCC modeling on the grounds they are not indicative of future resource performance, make ELCC unit-specific and include the full winter capability of thermal resources.

For new resources, accreditation would continue to be based on a class average with unit-specific data rolled in over time, similar to the precursor to ELCC — equivalent forced outage rate demand (EFORd).

Vistra's Erik Heinle argued eliminating performance data would disincentivize good performance by sending a signal that PJM will erase data from events with large-scale under-performance.

Bowring said PJM changed its operational approach after the commitment and dispatch mistakes of Elliott that led to the poor performance during the storm.

"Given those changes, illustrated by PJM's conservative operations during Polar Vortex 2025 in January, the performance during Elliott is not a useful risk metric," he said.

He said PJM's "forgetting factor" arbitrarily changes weights rather than relying on logic and actually increases the weight of Elliott in the ELCC calculations. He added PJM's ELCC for gas-fired combined cycles is only 75% based on Elliott performance data, while that ELCC is 96% on a forward-looking basis.

"No one other than PJM thinks that combined cycles are only 75% reliable," Bowring said.

Bowring also said while it is appropriate to recognize the increased winter capability of thermal resources, PJM's approach would arbitrarily increase the measured capability of thermal resources year-round, exposing generators to the risk of not meeting their maximum winter output even during the summer when maximum output is appropriately lower.

The Monitor's proposal received 35.8% sector-weighted support, with end-use customers unanimously supporting it and all other sectors voting with a quarter or less in support. ■

PJM: Baltimore Load Shed Caused by Tx Equipment Failure

By Devin Leith-Yessian

VALLEY FORGE, Pa. — An Aug. 11 load-shedding event in Baltimore was caused by equipment failure at the Brandon Shores substation, causing all breakers to open and cutting the city off from a major transmission feeder. (See *PJM Initiates Load Shed in Baltimore Region After Substation Disconnect*.)

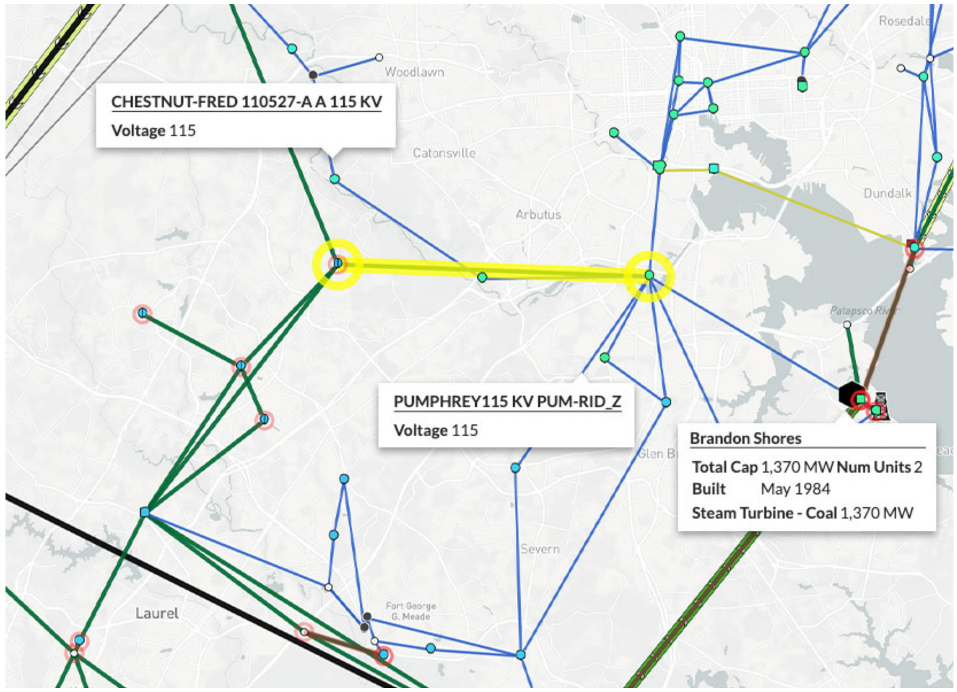
Isolated from the 230-kV network passing through Brandon Shores, increasing strain was placed on the 115-kV lines running into the city until PJM issued a load-shed directive at 3:52 p.m. The load-shed directive was preceded by a voltage reduction action initiated at 2:15 p.m.

About 20 MW of load was shed for 28 minutes to mitigate an identified N-5 cascading outage risk that could have taken 1,200 MW offline, PJM Director of Operations Planning Dave Souder said at the Aug. 20 Markets and Reliability Committee meeting. He said PJM worked closely with Baltimore Gas and Electric (BGE) to identify regions where load shedding would be most valuable.

"We knew early on that we were going to have to go into emergency procedures," Souder said.

Exelon Director of RTO Relations and Strategy Alex Stern said PJM worked extremely closely with BGE to limit the impact.

Six transmission lines intersect with the Brandon Shores substation, and two generators are tied into it: the 1,289-MW Brandon Shores and 843-MW H.A. Wagner, both owned by Talen Energy. The generators are running on reliability-must-run (RMR) agreements to maintain transmission security while network upgrades are constructed to facilitate their deactivation. (See *FERC Approves $180M Annually for RMR Deals with Brandon Shores and Wagner Plants*.)



PJM directed a load shed in the Baltimore region on Aug. 11 to avoid a cascade condition on the Chestnut-Frederick 115-kV line after the nearby Brandon Shores substation experienced an unplanned disconnect. | *Yes Energy*

Stakeholders questioned why the emergency procedures page and PJM Now mobile app incorrectly showed that the load-shed directive initiated a performance assessment interval (PAI), which would place capacity resources at risk of penalties if they failed to underperform.

PJM Senior Vice President of Operations Mike Bryson said staff took a broad stance on sending notifications that a PAI had been initiated to allay stakeholder concerns that capacity resources could be penalized without owners realizing an event had begun. Based on feedback since the Baltimore load shed, PJM is open to reconsidering how it sends those notifications and can add a discussion to the Sept. 11 Operating Committee agenda.

Souder added that the localized nature of the incident and its basis in a transmission emergency, rather than generation, precluded it from being a PAI. Responding to questions of whether a PAI would have been declared if load shedding were initiated across the BGE zone, he said they are declared for reserve zones, not transmission owner (TO) zones or subzones.

Bruce Campbell, of Campbell Energy Advisors, said the distinction between reserve and TO zones during emergency operations may not be widely known across stakeholders and may warrant further education. He added that there is only one reserve zone, which covers the full RTO, and one reserve subzone, Mid-Atlantic Dominion.

Several questions were raised about whether the two Talen generators were on outage during the event or if their availability contributed to the emergency. Souder said PJM does not publicly post information about generation outages and reiterated that the substation itself was unavailable. All available generation in the area was dispatched, but Brandon Shores was disconnected from the grid by the substation outage, and Wagner's start-up time prevented it from coming online until the next day. ■

What's Next

Based on feedback since the Baltimore load shed, PJM is open to reconsidering how it sends notifications and can add a discussion to the Sept. 11 Operating Committee agenda.

Developer Looks to Build 4 SMRs in N.J.

Small Modular Reactors Would Rise on Former Oyster Creek Site

By Hugh R. Morley

The company that plans to restart the Palisades nuclear facility in Michigan is pushing to build four 300-MW small modular reactors (SMRs) on the site of the decommissioned Oyster Creek Generating Station in New Jersey.

The company that owns the site, Holtec International of Camden, N.J., says the project would be accompanied by a solar farm that would take up much of the 700-acre site. The two projects together would generate 1,350 MW of clean electricity, making the site "a magnet for data centers on the lookout to meet their voracious appetite for clean energy," especially those interested in the site's proximity to markets such as Philadelphia and New York, the company said in a *statement*.

"Our plant, (called) SMR 300, is walk-away safe," Kris Singh, CEO of Holtec, said at a joint meeting of the state Assembly Environment, Natural Resources, and Solid Waste and Senate Environment and Energy committees on Aug. 14. "It has absolutely no risk. Everything is passive. It's not run by pumps and motors that can fail and cause an accident."

The project's ability to use the existing infrastructure left by the previous nuclear plant would provide "massive savings in development capital costs and production time," the company said *in a release*.

Why This Matters

The SMR proposal comes as the state, an energy importer, and other states served by PJM are facing a looming and dramatic shortfall in power, due in large part to the expected arrival of AI and other data centers.

The New Jersey Department of Environmental Protection (DEP) said it is "unaware" of any specific plans for the Oyster Creek site and added that the federal

The Palisades nuclear plant | *Holtec International*

Nuclear Regulatory Commission (NRC) has sole jurisdiction for the construction and operation of nuclear reactors. The NRC, which will hold a public meeting on the "termination plan" for the former generating station, did not respond for comment on a new plant rising.

Energy Crunch

Opened in 1969 on the Jersey Shore, the 650-MW Oyster Creek plant *ceased operations* in 2018 under an *agreement* between owner Exelon and the DEP to address concerns the plant's withdrawals of water from nearby Barnegat Bay and subsequent discharges damaged the environment. The operator opted not to install an expensive sealed cooling system with cooling towers to resolve the contamination problem.

Holtec's New Jersey SMR proposal comes as the state, an energy importer, and other states served by PJM are facing a looming and dramatic shortfall in power, due largely to the expected arrival of AI and other data centers. PJM estimates that of the 32 GW of demand increase expected in the PJM region by 2030, 30 GW will come from data centers. (See *N.J. Confronts Data Center Load Surge*.)

While Gov. Phil Murphy (D) vigorously pursued wind and solar projects, the state more recently has embraced nuclear energy, releasing a request for information in May to help the state explore the development of new nuclear plants as part of its effort to generate more power. (See *New Jersey Opts to Explore Nuclear Options*.)

"New Jersey is, and has been, a nuclear state," said Christine Guhl-Sadovy, Board of Public Utilities president, who noted that nuclear facilities in the state provide 40% of New Jersey's electricity. That power is provided by three nuclear facilities in South Jersey — Hope Creek, Salem 1 and Salem 2 — that either are operated or co-operated by the Public Service Enterprise Group (PSEG). The state has contributed $2 billion in subsidies to the upkeep of the plants, to ensure they remain part of the state's generating fleet, Guhl-Sadovy noted.

To demonstrate Murphy's commitment to nuclear power, Guhl-Sadovy said PSEG is "finalizing an upgrade of hundreds of megawatts at their existing plants, which will bring more capacity online."

Embracing Small Reactors

Two bills pending in the legislature address issues of interest to nuclear projects, although neither is close to enactment. *S4423* would enable the BPU to authorize site approval for an SMR in a municipality where a nuclear facility previously was located. The legislation would give the agency the ability to supersede municipal and county decisions to authorize reactors able to generate 300 MW of power or less. The reactors would be licensed by the NRC, and nuclear fuel would be stored on-site.

Another bill, *S422*, would establish a state Nuclear Power Advisory Commission, charged with "conducting a study and preparing a report on the role that nuclear energy power plants, including small-scale nuclear energy power plants, should play in the state's energy future."

Sen. Bob Smith (D), chairman of the Senate Environment and Energy Committee, who co-sponsored both bills, said he believes Holtec is on the right track.

"Oyster Creek is absolutely one of the right spots for SMR technology, and the distribution system already being there makes it even more valuable," he said. "We should talk, but you've got to have some skin in the game."

Smith said he had visited the location in Lacey, and township officials would be "welcoming of additional energy facilities down there. They took a tremendous economic hit in terms of employment lost as the plan shut down. They see it as a major asset for the town."

Holtec is reopening the 800-MW Palisades facility in Michigan, which shut down in 2022. The company has been awarded a $300 million grant by the state and a $1.52 billion loan guarantee by the U.S. Department of Energy, the company said. The project involves the development of two of the company's SMR-300 reactors.

"We had to achieve a long-term power agreement," said Kelly Trice, Holtec president. "We did achieve a 30-year power agreement. Nuclear can't live on three-year power agreements. It's just stupid. No one's going to amortize that kind of money over that amount of time. And that's where I think the grid operators need to change their math. Nuclear plants, on average, last 100 years."

He said the company expects to break ground at the end of 2027 on the project and "be on the grid in 2031, both plants." ■

N.J. Boosts Storage, Community Solar Program Capacity

Governor Signs Package to Create 3,000 MW of Solar

By Hugh R. Morley

Two laws signed by New Jersey Gov. Phil Murphy (D) aim to dramatically expand community solar and storage incentive programs as the state searches for new generation sources to help meet a predicted energy shortfall.

One of the laws, *S4530*, instructs the New Jersey Board of Public Utilities (BPU) to increase the capacity of community solar by 3,000 MW by 2029, or whenever the limit is reached. The state's current allowed capacity is 150 MW a year, although a one-time measure increased it to 250 MW in 2025.

The second law, *S5267*, requires the BPU to launch an incentive program that would stimulate the development of "transmission-scale energy storage systems," those with a capacity of at least 5 MW that are connected to PJM. The total project capacity would be 1,000 MW. In the first phase of the project, the legislation requires the BPU to approve projects with a capacity of at least 350 MW by the end of 2025 and approve the remainder by June 30, 2026. Eligible projects must have a commercial operations date of no later than Dec. 31, 2030, and have completed the PJM connection process to the system impact study stage.

Under the law, the BPU must allocate $60 million each year to the incentive fund.

Why This Matters

Officials in New Jersey, an importer of energy, argue that solar and storage development are key elements in the effort to boost electricity generation, and that the two methods can create power more cheaply and rapidly than would be possible by developing other sources, such as nuclear or gas generation.

New Jersey Gov. Phil Murphy signs into law two clean energy bills. | *New Jersey Governor's Office*

"This legislation addresses real problems," said BPU President Christine Guhl-Sadovy. "More New Jerseyans will get access to the benefits of expanded community solar programs — one of the best ways for residents to lower their utility bills while contributing to clean energy in the Garden State. And large-scale battery storage will strengthen our electric grid and keep the lights on when we need it most."

Officials in New Jersey, an importer of energy, argue that solar and storage development are key elements in the effort to boost electricity generation, and that the two methods can create power more cheaply and rapidly than would be possible by developing other sources, such as nuclear or gas generation.

New Jersey, like other states in PJM, faces a dramatic increase in demand, due mainly to the expected development of energy intensive data centers. PJM also argues that future energy capacity has been hindered by the closure of fossil generating sources at a faster pace than new sources — mainly clean energy — have come online to replace them.

Officials say the predicted shortfall in generation contributed to a 20% increase in the average New Jersey electricity bill in June.

Powering 1M Households

Murphy said he expected the new laws to "build a cleaner, more resilient future" for state residents.

"By accelerating the process for bringing new sources of energy online and rapidly building new energy storage facilities, we will meet growing demand while also making life more affordable for our state's families," he said at a press conference Aug. 22.

The New Jersey branch of the Sierra Club said the solar legislation would "enable the equivalent of one million households to receive solar power by 2028." The storage bill will "vastly" accelerate the construction of storage in the state, the environmental group said in a release.

"Energy storage is essential to make renewable energy sources like solar provide energy to its fullest potential by allowing excess energy generated during sunny periods to be saved for peak demand," said Anjuli Ramos-Busot, director of the club's state branch. "Incentivizing transmission-scale energy storage while increasing community solar targets will generate more power capacity, help reduce cost of electricity, improve grid reliability, reduce emissions and combat climate change."

New Jersey's community solar program has been a bright spot, and a source of pride for state officials. The first two solicitations in the program were fully subscribed, allocating 500 MW of capacity. A third solicitation is underway. The program is seen as a key element in the state's goal to reach 12.2 GW of solar energy by 2030 and 32 GW by 2050.

The *BPU's June report* showed that 456 community solar projects were providing 740 MW, or about 11%, of the state's 6.56 GW of installed solar capacity. BPU officials in the past opposed efforts to dramatically expand the program, saying the extra stress would negatively impact the state's solar programs. (See *NJ BPU Opposes Community Solar Program Expansion*.)

New Jersey has struggled to develop storage. The state missed a legislative goal of developing 600 MW of storage by 2021 and now is seeking to put 2,000 MW of storage in place by 2030. (See *Developers Seek Deadline Extension in NJ Storage Plan*.) ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse Reworked Interconnection Jurisdiction

PJM's Markets and Reliability Committee endorsed by acclamation a PJM *proposal* to rework how it determines whether a new generation point-of-interconnection (POI) falls under federal jurisdiction — and therefore under the RTO's purview — or state oversight. (See "Stakeholders Endorse POI Jurisdiction Changes," *PJM PC/TEAC Briefs: July 8, 2025*.)

The changes would establish a "bright-line" test where a POI of 69 kV or higher would fall under FERC jurisdiction, while lower-voltage facilities would be delegated to the states. A backstop provision could override that determination if the cost-recovery methodology approved by FERC, the transmission owner or relevant electric retail regulatory authority (RERRA) has classified the POI as either transmission or distribution. The existing "first-use" test considers the first wholesale resource to interconnect at a distribution asset as falling under state or local jurisdiction, with all subsequent interconnections being federal.


PJM's Thomas DeVita | © RTO Insider

PJM associate general counsel Thomas DeVita said resources interconnecting with distribution-level facilities tend to be simpler in nature and better lend themselves to a wholesale market participation agreement (WMPA) compared with a more complex generation interconnection agreement (GIA). Placing more resources on the path to receiving a WMPA would free up interconnection staff to focus on more demanding applications. The RTO has estimated that around 12 to 15% of interconnections approved since the introduction of the WMPA pathway would have been affected by the proposal if it had been implemented at that time.

He compared PJM's proposal to ISO-NE's shift to require distributed energy resources (DERs) to go through state or local interconnection processes, a change the commission approved in August 2022 (*ER22-2226*). (See *FERC Approves Changes to ISO-NE DER Interconnection Process*.)

DeVita said PJM is aiming to file the changes with FERC in October, followed by implementation in spring 2026.

1st Read on Expanded Provisional Interconnection Service


PJM's Donnie Bielak | © RTO Insider

PJM Director of Interconnection Planning Donnie Bielak presented a first read on a *proposal* to allow more flexibility around when new resources can begin operating while network upgrades are being completed. The proposal is set to be voted on by the Planning Committee on Sept. 9, followed by the MRC on Sept. 25.

The change would allow interim deliverability studies to determine that a resource is capable of partial operations and receive provisional interconnection service. The studies currently only look at whether a resource can reach its full output without causing transmission violations and prohibit them from coming into service if issues are identified. When provisional interconnection service is granted for a resource capable of partial operations, an operational guide would be produced for dispatchers to understand conditions under which the unit could be dispatched.

The revisions to Manual 14H: New Service Requests Cycle Process would allow resources to operate as energy-only for a specific delivery year, with their output determined by the interim deliverability study. They would not receive capacity interconnection rights (CIRs) or a capacity commitment for that delivery year. Bielak said the proposal is intended to allow resources to enter service faster and make more energy potential available for dispatchers as load growth is expected to continue to eat away at the reserve margin.

Independent Market Monitor Joe Bowring said the plan seems like an excellent idea to improve an interconnection process that has long been criticized as being backlogged.

Stakeholders requested there be more transparency on resources that would receive provisional interconnection service to ensure a level playing field on hedging.

Exelon's Amber Thomas said there needs to be more information about the study cases PJM plans to use on this to ensure the RTO does not assume network upgrades will be complete in time for a unit to achieve partial operations, only to find that transmission will not be completed on time. Bielak responded that the cases would only include upgrades set to be complete by the delivery year in which the unit would begin provisional operations.

Market Design Project Road Map

PJM *presented* a "refresh" of its Market Design Project *Road Map* to include several new stakeholder efforts, including a Critical Issue Fast Path (CIFP) process the board initiated in August addressing large load growth and exploring a sub-annual capacity market. Executive Director of Market Design Rebecca Carroll said the RTO's goal is to update the road map twice a year to ensure that all stakeholders are aware of what the market design team is focused on.

Much of the road map centers on addressing a tightening balance between supply and demand as load growth runs up against resource deactivations and lagging new entry. PJM presented a conceptual *proposal* to create a non-capacity-backed load (NCBL) service that could be triggered as a reliability backstop.

Once initiated, new large loads could elect or be assigned to accept interconnection service without a corresponding capacity obligation, reducing the amount of load participating in a particular Base Residual Auction (BRA) and allowing the large load to avoid capacity charges. The first stage of the CIFP process is to begin Sept. 2, with the final meeting scheduled for Nov. 19 and a FERC filing targeted for December. (See *PJM Board Initiates CIFP Addressing RA, Large Loads*.)

The MRC voted in July to endorse an *issue charge* brought by Pennsylvania Gov. Josh Shapiro calling on PJM to hire a consultant to draft a report exploring the possible benefits and drawbacks of implementing a sub-annual capacity market design. Supporters argued that a more granular market could allow capacity auctions to be more tailored to the risks inherent in each season or interval. The issue charge anticipates the report will be completed by December, after which the road map includes a "capacity market reforms" item including further exploring a sub-annual or prompt auction design between early 2026 and halfway through 2027. (See *PJM Stakeholders Support Sub-annual Capacity Issue Charge*.)

Ongoing efforts to revise PJM's effective load-carrying capability (ELCC) accreditation and risk modeling paradigm, a *pro forma* reliability-must-run (RMR) agreement and the Quadrennial Review of parameters for the 2028/29 BRA are all set to continue through the second quarter of 2026.

Additional efforts on the energy and ancillary service markets include evaluating how resources with advance commitments fit into the day-ahead energy market, renewable dispatch, load flexibility and reserve certainty. The road map also includes work on energy storage modeling beginning in 2026 and "additional essential reliability service products" starting in 2027.

The PJM Board of Managers letter outlining the CIFP process envisions faster interconnection studies and capacity market changes to boost resource adequacy.

LS Power's Dan Pierpont said it's important that PJM is willing to discuss how each of the work items might interact with each other. In particular, he said the market parameters defined by the Quadrennial Review could be impacted by market changes arising from the CIFP process focused on large load additions.

PJM Exploring Refiling CIR Transfer Proposal

PJM is drafting changes to its proposal to expand the process for transferring CIRs from a deactivating resource in the wake of a FERC rejection (*ER25-1128*). The commission faulted the proposal's inclusion of an indefinite extension of the replacement resource's in-service date, finding that it could lead to withholding of transmission access. (See *PJM Stakeholders Endorse Coalition Proposal on CIR Transfers*.)

"We find that PJM's lack of a maximum time limit for the one-time option for an extension of a Replacement Generator Resource's Commercial Operation Date regardless of cause renders PJM's proposal unjust and unreasonable because it undermines the purpose of the generator replacement process," the commission wrote in its order. "That is, the main purpose of the generator replacement process is to avoid duplicative study costs and operational costs that otherwise would occur when the request to replace an existing generating facility must proceed through the interconnection study queue process, which will in turn avoid delaying the replacement of older resources with more efficient and cost-effective resources."

Bielak said staff is planning to bring a proposal to the Sept. 9 Planning Committee meeting alongside any stakeholder alternatives. An endorsement vote is anticipated at the Sept. 25 Members Committee meeting.

NRDC advocate Claire Lang-Ree encouraged PJM to consider also the ambiguous language around the in-service requirements for resource types with long development timelines, an issue about which the commission recommended PJM include more information. While it was not included as a rationale for rejecting the filing, the commission wrote that exempting resources with "industry-recognized significant construction timelines" from the three-year commercial operation date requirement lacks clarity.

"We also agree with PJM's goal of offering Replacement Generation Resources that face long lead times a certain degree of flexibility with respect to achieving commercial operation, and agree that such resources 'can make a significant contribution to meeting resource adequacy needs, at a time when PJM needs additional resources to maintain reliability,'" the commission wrote.

Stakeholders Endorse RPM Seller Credit Requirements

The MRC endorsed by acclamation a *proposal* to add a creditworthiness review before capacity market participants are offered Reliability Pricing Model (RPM) seller credits — unsecured credit available to satisfy BRA participation requirements. The credit available amounts to twice the average total net monthly bills over the prior year, up to the $50 million unsecured credit allowance cap.

Senior Director of Credit Risk and Collateral Management Gwen Kelly said the proposal is consistent with credit evaluation required in other instances where PJM offers credit and would not change the credit calculation or limit. The changes are set to be voted on by the MC on Sept. 25.

PJM Reviews Proposal on Regulation Resources at NEM Sites

PJM's Pete Langbein presented a first read on a *proposal* to allow demand response resources seeking to offer regulation-only service to participate in the market at sites where there is the capability for energy injections. It would allow a DR customer to offer regulation when there is no load or a net injection at its POI if they have received authorization from the relevant electric distribution company (EDC) and it's reflected in a net energy metering (NEM) agreement. (See "Stakeholders Endorse Changes to Storage Participation in Regulation Market," *PJM MIC Briefs: July 9, 2025*.)

The change is part of PJM's planned implementation of the distributed energy resource (DER) requirements in FERC Order 2222 and scheduled to be rolled out in 2029.

Market Monitor Joe Bowring stated that the proposal is a one-off proposal that represents special treatment for a specific stakeholder and should not be an exception to the broader process that had been approved by FERC for implementation in 2029 for all market participants.

Members Committee

PJM Seeks to Codify Process for Filling Committee Chair, Vice Chair Vacancies

PJM's Michele Greening presented a first read on *revisions* to Manual 34 to establish a process for filling a temporary vacancy in the MC chair or vice chair position.

Under the proposal, if the chair takes a temporary leave, the vice chair would fill in and the most recently elected chair to have finished their term would cover the vice chair position. If that individual is unavailable, a past chair can be selected to fill the vice chair position. A similar process would be used to cover a temporarily absent vice chair. The revisions also include a statement that candidates for either position "should have a reasonable expectation that they will be able to serve a complete term." ■

— Devin Leith-Yessian

SPP MOPC Passes Revised Large Load Policy

By Tom Kleckner

SPP stakeholders have approved a revised version of the grid operator's fast-track study to integrate high-impact large loads (HILLs) during a special virtual meeting of the Markets and Operations Policy Committee.

MOPC members resoundingly shot down the proposal during their July quarterly meeting, giving it only 53.7% approval. They said the fast-track study policy was a rushed process outside of the normal stakeholder structure and didn't give them enough time to review the revision request (*RR696*).

Since then, staff have stripped out conditional high-impact large load service (CHILLS) and the design associated with dispatch, study and charges for the service from its original proposal. It also removed one of three paths for high-impact large load generation assessment (HILLGA).

The changes met with success. MOPC members complimented staff on the revisions and then gave the measure 95.7% approval. The transmission owner and transmission user sectors each had one dissenting vote, with 15 total abstentions.

"We're reviewing an improved product compared to what we discussed in July, so appreciate all the time and effort to get here today," Southern Power's Chase Smith said during the meeting.

"I know … there was a desire for members just to have a little bit more time to get more comfortable," SPP COO Antoine Lucas said. "Today, we'll do what we can to close out that effort and be able to move this forward to the next stage."

SPP's Board of Directors delayed consideration of RR696 during its August meeting to allow a follow-up session for MOPC to discuss the issue further. (See *SPP Board Sets Aside 765-kV Costs, Large Load Policy*.)

The board and the RTO's state regulators now will take up the HILL proposal. SPP has scheduled an education session for the board, its Members Committee and the Regional State Committee for Sept. 3. The board then will hold a call Sept. 4 to consider HILLs and Southwestern Public Service's out-of-bandwidth 765-kV project, which also was set aside by the directors.

MOPC approved a design focused on HILLs and HILLGA paths as revised by staff's *latest comments*, filed Aug. 14. Approval is contingent upon SPP modifying the tariff to reinstate a 60-day study under Attachment AQ, which governs upgrades or other changes to delivery point facilities.

HILL studies will remain on a 90-day timeline. Changes include a revised HILL definition that clarifies its transmission service study process and its independence from non-conforming load.

A HILL is defined as a new commercial or industrial load or an increase to existing load at a single site, connected through one or more shared interconnection or delivery points. Load can be either 10 MW or more if connected to the system at a voltage level less than or equal to 69 kV, or 50 MW or more if connected at a voltage level greater than 69 kV.

SPP says its HILL proposal will result in more robust study analysis, with large loads and their support generation studied together. It still includes load forecasts and ride-through requirements, with two HILLGA paths: a common bus or a local area.

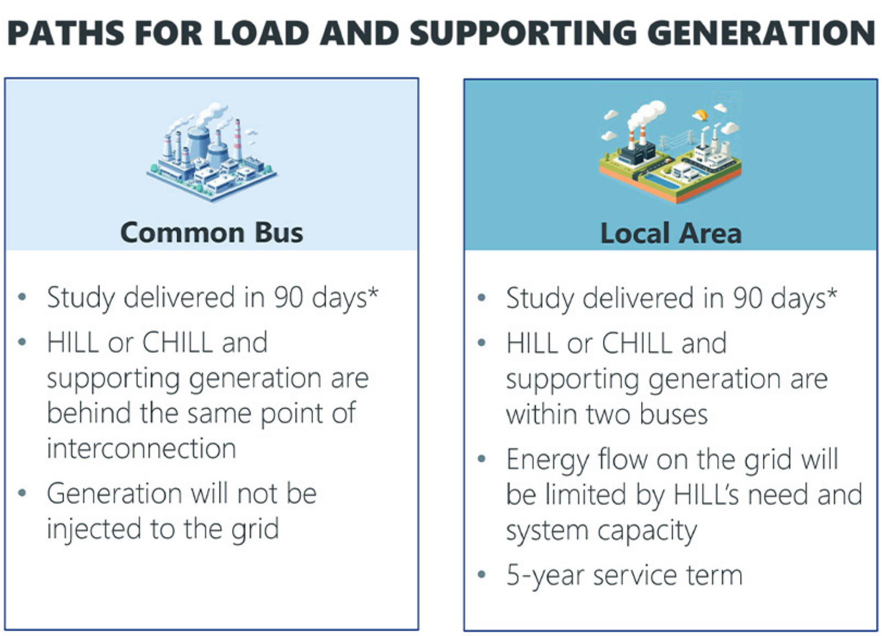
Costs will be allocated to the cost-causers:

- HILLs using a delivery point assessment will have their upgrades base-plan funded.
- Upgrades from HILLs using a provisional load process will be directly assigned until the customer acquires firm service for new generation.
- Upgrades from HILLs bringing supporting generation to a local area will be directly assigned to the generation customer.

The CHILLS policy will be taken up during the MOPC, RSC and board meetings in October and November. Staff will hold education sessions before then with various working groups and the RSC. ■

What's Next

SPP's Board of Directors, Members Committee and the RTO's state regulators now will take up the large load design during a pair of special meetings in September. An additional large load design will be considered in October and November.



Assessment paths for large loads and their supporting generation | *SPP*

FERC Approves SPP's Separate Winter, Summer PRMs

By Tom Kleckner

FERC approved SPP's tariff revision that establishes separate planning reserve margins for the summer and winter seasons, saying it will provide "more granularity" by recognizing the reliability differences between the two seasons (*ER25-89*).

"We find that having separate, seasonal PRMs will help align resource adequacy requirements with seasonal reliability risks, which have been increasingly occurring in the winter season," the commissioners wrote in their Aug. 19 order. "Moreover, as SPP points out, separate PRMs will help ensure that [load-responsible entities] are appropriately planning for both seasons."

FERC granted the RTO's request for an Oct. 1 effective date.

SPP performs a probabilistic loss-of-load expectation (LOLE) study at least biennially to determine the PRM. It told FERC that its 2024 report identified a predominant loss-of-load risk in the winter because it included incremental cold-weather outages in the 2023 study that would increase with the additional incorporation of intermittent resources.

Under the grid operator's resource adequacy requirement (RAR), staff first determine a PRM based on an LOLE study analyzing the ability to reliably serve the balancing authority area's forecasted annual peak demand, based on a one-day-in-10-years loss-of-load standard and the accredited value of the footprint's resources. LREs are responsible for owning or procuring the capacity to meet their seasonal non-coincident peak load plus the PRM.

The Arkansas Electric Cooperative Corp. (AECC), East Texas Electric Cooperative and Northeast Texas Electric Cooperative protested SPP's filing. AECC expressed concerns that the 2023 LOLE study results failed to assign an LRE's winter RAR proportionately to its contribution to cold-weather outages, saying the grid operator failed to support its move from an annual peak demand construct to a seasonal PRM framework.

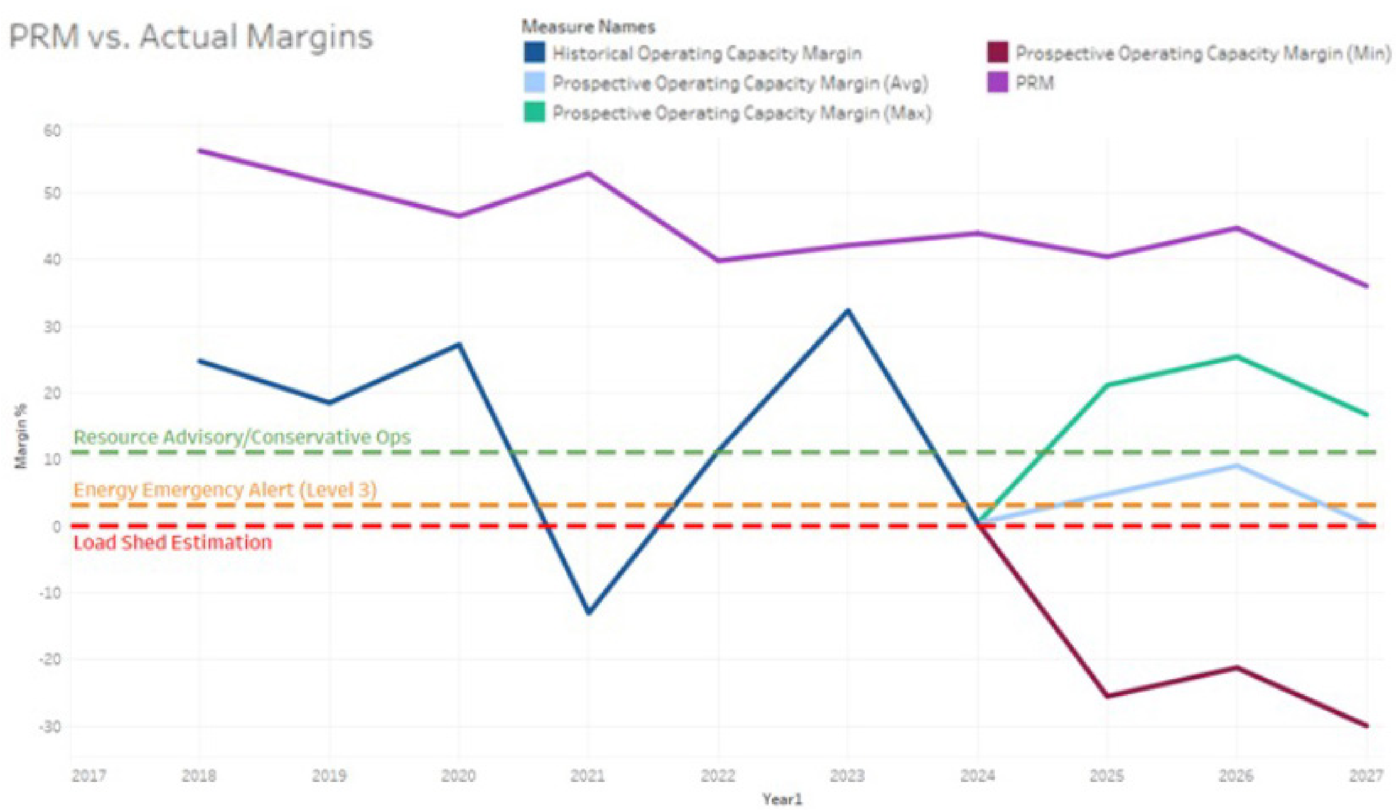
AECC and the other two cooperatives asserted that the PRMs' swift implementation prevented a "robust consideration" of alternatives by members during the stakeholder process.

FERC rejected the arguments, noting it already had found SPP's seasonal RAR construct just and reasonable.

The commission found that SPP's proposal to use expected unserved energy (EUE) as one of the determinants will produce a more robust PRM. It said EUE "provides data on the magnitude and duration of outage events and is impacted by changes in load shape and load peak duration" that differ from season to season.

SPP's board approved the separate PRMs in August 2024 despite stakeholder concerns. The approval set a 36% PRM for the winter season and a 16% margin for the summer, effective for 2026/27 and 2026, respectively. (See "Board Approves 36% PRM for Winter over Stakeholder Objections," *SPP Board of Directors/RSC Briefs: Aug. 5-6, 2024*.)

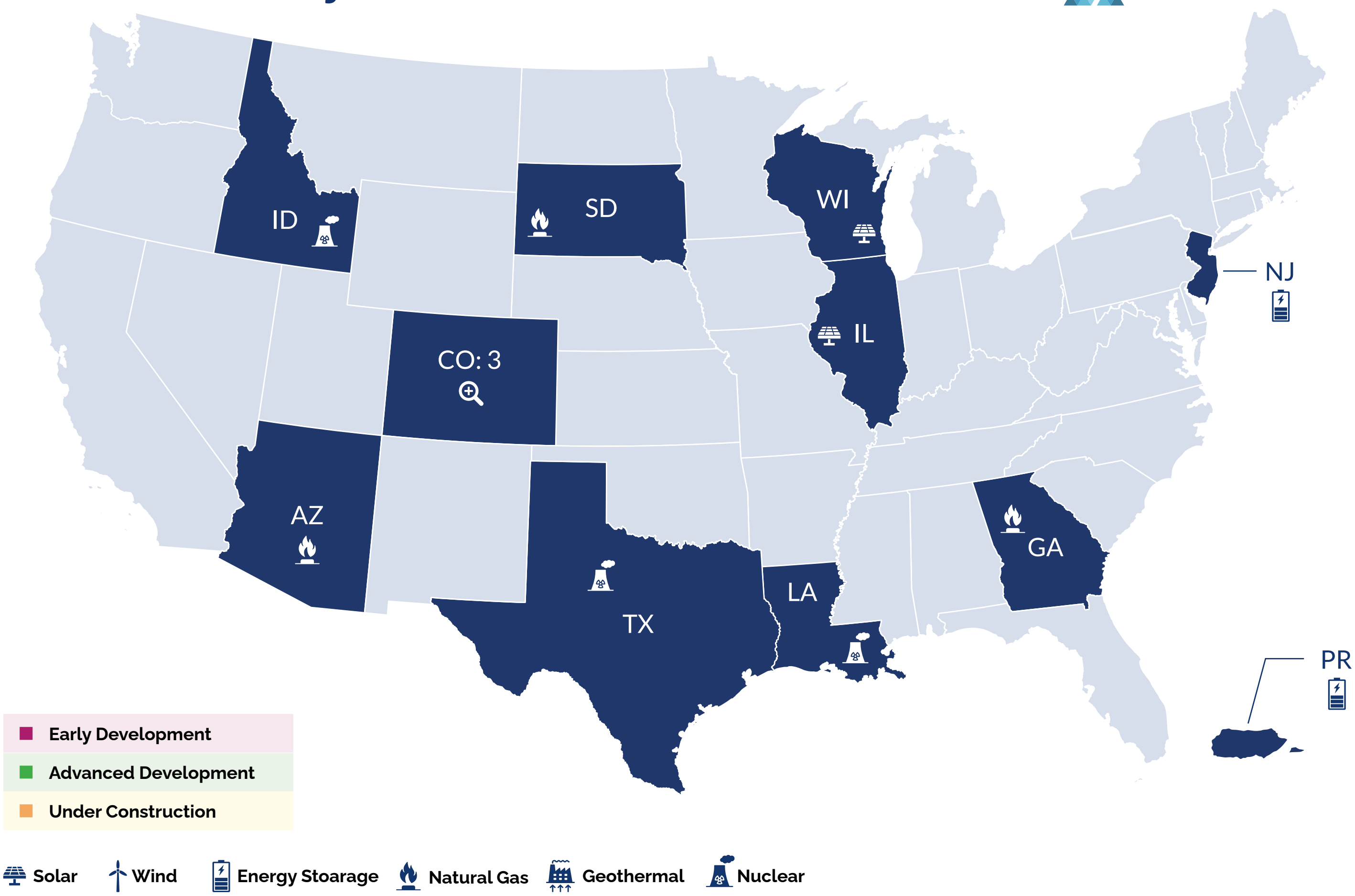
The grid operator's stakeholders had recommended a 33% winter PRM. ■



A slide from a 2024 SPP presentation shows the difference between a winter PRM and operating capacity margins. | *SPP*

Generation Projects Added in the Past Week

YES ENERGY



Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
Coolidge Generating Station Expansion Phase 2	Salt River Project		AZ	288	2027
Pivot Energy CU Boulder Solar (unofficial name)	Energy Capital Partners	Pivot Energy	CO	5	2026
Vega Solar (CO)	Enfinity		CO	120	2031
Vega Solar BESS (CO)	Enfinity		CO		2031
Plant Yates Unit 9	Southern Company	Georgia Power	GA	483	2027
Aalo-X Experimental Reactor	Aalo Atomics		ID	50	2027
Ghost Hollow Road Solar	Energy Capital Partners	Pivot Energy	IL	3	2100
Waterford 3 Steam Electric Station Upgrade	Entergy	Entergy Louisiana Inc	LA	45	2026
Bayonne Energy Center III aka BEC III	Morgan Stanley	TigerGenCo, LLC	NJ	50	2028
Punta Lima BESS	Polaris Renewable Energy	Polaris Power US, Inc.	Puerto Rico	71	2026
Lange II Generating Station	Black Hills Corp.	Black Hills Energy	SD	100	2026
Last Energy Haskell County Microreactor Project	Last Energy		TX	600	2029
Lime Kiln Solar	OneEnergy Renewables		WI	6	2026

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

Company Briefs

Hitachi Energy Invests $106M in U.S. Transformer Supply Chain

Hitachi Energy last week announced it will invest $106 million to expand a transformer components factory in Tennessee.

The expansion will add 60,000 square feet to the factory, which is scheduled to be finished by mid-2027. Once completed, the facility will become the largest bushings manufacturing site in North America.

More: *Latitude Media*

Meta Data Center to Purchase Most of Solar Farm Power

Meta's planned $800 million AI data center will serve as the anchor customer for Silicon Ranch's 100-MW solar farm in South Carolina.

The project, slated for Orangeburg County, will be developed, owned and operated by Silicon Ranch in coordination with Santee Cooper. Central Electric Power Cooperative will purchase the power from Silicon Ranch to supply its 19-member distribution cooperatives, including Aiken Electric Cooperative, which will directly serve the data center. Meta will receive all renewable energy credits associated with the solar farm, the company said.

More: *Latitude Media*

Federal Briefs

U.S. Extends 50% Steel Tariff to Wind Turbines, Components

The U.S. Department of Commerce last week extended its "derivative" sectoral tariffs to wind turbines and their parts and components, meaning the steel and aluminum content of these products will be subject to a duty rate of 50%.

In 2024, the U.S. wind industry imported $2.7 billion worth of equipment, up 70% from the prior year, across three main product areas: blades and hubs (49%), towers (31%) and nacelles (19%), with the remaining 1% consisting of generator parts and sets.

The extended tariffs are effective immediately.

More: *Recharge*

Renewable Project Cancellations up to $18.6B in 2025

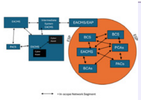
Clean energy projects worth $18.6 billion have been canceled this year, compared with just $827 million in 2024, according to Atlas Public Policy's Clean Economy Tracker.

Investment announcements also fell by nearly 20% to $15.8 billion this year, compared to $20.9 billion in the same period in 2024.

The DOE has cut $3.7 billion in grants, while a further $8.5 billion in loans have been canceled or remain at risk.

More: *Financial Times*

National/Federal news from our other channels

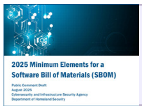


FERC Responds to ERO's INSM Clarification Filing — ERO Insider

NERC Standards Committee Tackles Final Order 901 Tranche — ERO Insider

Texas RE Analyst Urges 'Extravagant' Utility Cyber Plans — ERO Insider

MRO Leaders Applaud ERO Progress, Collaboration — ERO Insider



CISA Seeks Comments on New SBOM Guidance — ERO Insider

First-of-its-kind Hydrogen Trial Set for Linear Generator — NetZero Insider

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

State Briefs

CALIFORNIA

San Diego-Coronado Ferry Ditches Diesel Boats for Electric Ferries

The San Diego-Coronado Ferry last week announced it plans to replace two diesel-powered ferry boats with electric boats.

The boats cost more than $21 million in total, although the Air Resources Board provided Flagship Enterprises, who operates the ferry, with a $15.3 million grant.

The boats will be operational in the fall of 2026.

More: *The San Diego Union-Tribune*

COLORADO

PUC Questions Xcel Energy's Investment Costs

State regulators last week openly questioned Xcel Energy's plan to invest $22.3 billion in state infrastructure by 2032.

The commissioners questioned whether the investments were driven by the company's financial incentives while leaving most of the risk on customers. The company's expectations for sales growth over the next few years were also as much as 40 times above historical growth rates.

The investments will raise its electric assets in the state from $8 billion in 2021 to $36 billion in 2029 and more than $44.6 billion in 2032, according to filings.

More: *The Colorado Sun*

IOWA

Shelby, Story Counties to Pursue Action on Pipeline Ordinance Case

Shelby and Story County supervisors last week voted to pursue further legal action in their case against Summit Carbon Solutions pertaining to county-specific ordinances on hazardous liquid pipelines.

A U.S. district judge and federal appeals judges have previously ruled in favor of Summit, and now the counties are seeking a review of the rulings from the U.S. Supreme Court, though a Summit filing holds the ordinances would still be preempted by state laws.

Ordinances in both counties established setbacks and permitting requirements for the pipeline company to construct in the county. Summit argued, and a federal judge in the Southern District of Iowa ruled, that the ordinances were preempted by federal pipeline safety standards. The counties appealed the case, and judges for the 8th Circuit Court of Appeals concurred with the lower court, though one judge partly dissented on the case.

More: *Iowa Capital Dispatch*

MONTANA

Puget Sound Energy Wind Farm Becomes Fully Operational

Puget Sound Energy last week announced its 248-MW Beaver Creek wind farm in Stillwater County is now fully operational.

The project uses existing company transmission on the Colstrip Transmission System to bring the wind energy back to customers in Washington.

More: *Daily Montanan*

NEBRASKA

Dakota County Commission Advances Solar Farm Plans

The Dakota County Planning and Zoning Commission last week advanced plans for a 360-MW solar farm.

The planning commission recommended sending the project plans to the Dakota County Board of Commissioners for final approval or veto. The project, from Mission Clean Energy, will sit on 2,900 acres.

More: *Sioux City Journal*

NEW MEXICO

NNSA Finds 'No Significant Impact' for Proposed Tx Line

The National Nuclear Security Administration has issued a finding of "no significant impact" for a proposed 14-mile, 115-kV transmission line to service Los Alamos National Laboratory and Los Alamos County.

The finding document, signed by NNSA Los Alamos Field Office Manager Ted Wyka, stated that due to an insufficient regional power supply and "extensive maintenance problems" with existing lines, outages could become more frequent if the project doesn't move forward.

The DOE requested $88 million for fiscal 2026 for the project, although the total cost range is between $215 million and $349 million, according to budget documents. The project is expected to be completed between 2028 and 2030.

More: *Santa Fe New Mexican*

NEW YORK

NYC Launches First Hybrid-electric Ferry

Harbor Charger, a hybrid-electric vessel, entered service Aug. 12 and is the first of its kind in New York state.

The $33 million ferry uses diesel-fueled generators to charge up its 870-kW battery system, allowing it to run partly or fully on electricity during the eight-minute trip to or from Governors Island. The ferry will eventually plug in directly to a shoreside rapid-charging station, using the generators only as emergency backup, but the infrastructure has yet to be built.

Harbor Charger will replace its 69-year-old predecessor, named Lt. Samuel S. Coursen, which consumes an average of 420 gallons of diesel per day. The new boat will slash carbon dioxide emissions by nearly 600 tons annually when running in hybrid mode.

More: *Canary Media*

OHIO

Board Approves Solar Project, Denies Rehearing of Another

The Power Siting Board last week approved the 220-MW Eastern Cottontail solar project in Fairfield County.

Developer EDF Power Solutions now has state permission to start installing solar panels on about 1,550 acres of private farmland. The project is expected to be operational by 2026.

The board also voted 8-1 to deny a rehearing on its previous approval of the 120-MW Frasier Solar project.

More: *WOSU*; *Knox Pages*