ISSN 2377-8016 : Volume 2025/Issue 17 ▪ April 29, 2025

YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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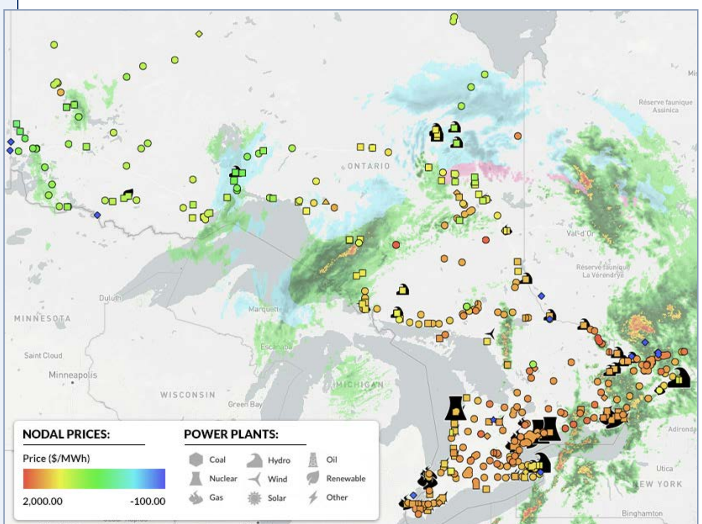
IESO

Ontario Introducing Nodal Market May 1



Yes Energy

Ontario's current system is inefficient at selecting least-cost resources and leads to excessive uplift costs. The new nodal market will put IESO in line with practices at all seven U.S. organized markets.

CONTINUED ON P.17

What to Know About IESO *(p.21)*

FAQs: Ontario's Shift to a Nodal Market *(p.23)*

Editor's note: This issue of *RTO Insider* marks the beginning of our regular coverage of Ontario's Independent Electricity System Operator (IESO).

ERCOT

Admin Monitor

Texas PUC Approves 765-kV Transmission Option for Permian Basin (p.15)

The three 765-kV import paths into the oil-rich Permian Basin are more expensive than the alternative five 345-kV lines, but the PUC said the long-term benefits outweigh the costs.

SPP

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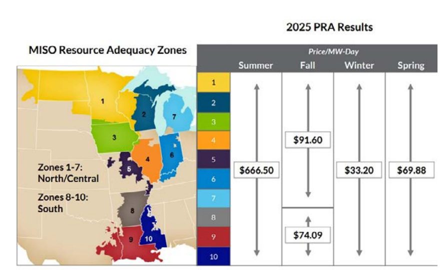
MPEC Members Celebrate Markets+ Funding Order (p.46)

Interested participants in SPP's Markets+ day-ahead market are celebrating FERC's approval of a funding agreement and its recovery mechanism. The approval clears the way for the RTO and its new stakeholders to focus their attention on Phase 2, when they will develop the software, systems and process for their implementation.

After Hitting Milestones, Markets+ Participants Advance on Phase 2 *(p.48)*

MISO



MISO

MISO Summer Capacity Prices at $666.50 for 2025/26 Auction (p.27)

A few LSEs in MISO may have sticker shock over summer 2025 capacity auction prices jumping to $666.50/MW-day from $30/MW-day a year ago. MISO said auction pricing bolsters its case that members need to add generation now.

MISO Debuting Flag System to Curb Deviations from Dispatch *(p.28)*

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In this week's issue

FERC/Federal

ACORE Report Explains How to Get Advanced Transmission in Regional Plans . 3
Commissioner Willie Phillips Announces his Resignation from FERC 5

CAISO/West

Oregon House Passes Bill to Shift Energy Costs onto Data Centers 7
APS to Keep Cholla Plant Closed Despite Trump Order Backing Coal 9
Calif. Lawmakers to Discuss Amendment Requests to Pathways Bill 10
Calif. Senate Committee Backs Pathways Initiative Bill 11
Consumers Defend Local Transmission Planning Complaint from Protests 12
CPUC, Others Question Details of EDAM Congestion Revenue Proposal 14

ERCOT

Texas PUC Approves 765-kV Transmission Option for Permian Basin 15

IESO

Ontario Introducing Nodal Market May 1 17
What to Know About IESO 21
FAQs: Ontario's Shift to a Nodal Market 23

ISO-NE

Maine PUC Seeking Feedback on Transmission, Generation Procurement . . . 26

MISO

MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction 27
MISO Debuting Flag System to Curb Deviations from Dispatch 28
Consumer Groups Invoke DOJ Stance in Stalled Complaint on ROFRs in MISO Planning 29
MISO: New Software Effective, Faster than Previous Queue Study Process 31
MISO, PJM Forgo Typical Interregional Studies for Novel Transfer Work 32
Oxbow Incident: FERC Denies Solar Farm's Waiver 33

NYISO

Clean Path Transmission Plan Draws Support, Criticism 34
FERC Partly Accepts NYISO Order 2023 Compliance Filing 36
Firm Fuel Proposal Continues to Confuse NYISO Stakeholders 37
Plan Lays out Steps for State-led Interregional Transmission in Northeast 38

PJM

Stakeholders, NERC Respond to FERC Large Loads Investigation 39
FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor 42
PJM MRC/MC Briefs 44

SPP

MPEC Members Celebrate Markets+ Funding Order 46
After Hitting Milestones, Markets+ Participants Advance on Phase 2 48
SPP Stakeholders Open Discussion on Affordability 50
FERC Approves SPP's Funding Plans for Markets+ 52

Company News

Xcel 'Optimistic' It Will Handle Tariffs, Trade War 53
NextEra Energy Continues to Rack up Renewables Deals 54

Briefs

Company Briefs 55
Federal Briefs 55
State Briefs 55

ACORE Report Explains How to Get Advanced Transmission in Regional Plans

By James Downing

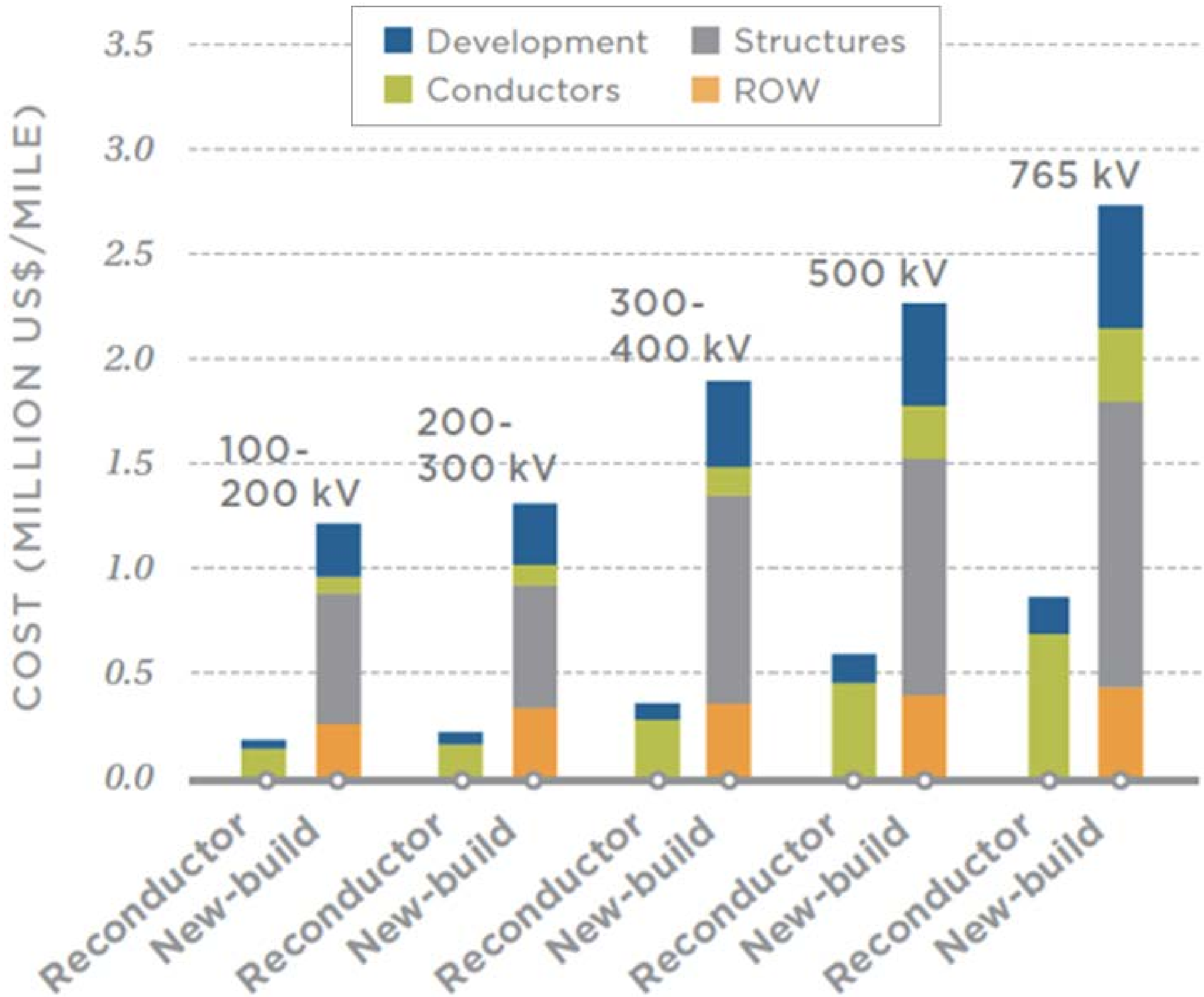
If FERC Order 1920 is implemented correctly, it could expand the role of grid-enhancing technologies (GETs) and high-performance conductors (HPCs) to help meet surging power demand in the near term, according to a *report* prepared by the Brattle Group for the American Council on Renewable Energy released April 22.

Demand forecasts have grown significantly since FERC started the rulemaking process that produced Order 1920, report lead author and Brattle Principal Bruce Tsuchida said on a webinar. That comes on top of the underlying need to replace aging transmission, which the report estimated would cost $10 billion annually over the next decade.

"If you're a state right now, and you're looking at the wave of infrastructure that's coming down the pipe to meet load growth, you probably are wondering, 'how much is this going to cost me?' And maybe, 'how could I shave off some of that cost? How can I save some money?'" GQS New Energy Strategies

Why This Matters

With FERC dealing with rehearing, the focus on Order 1920 is firmly in the compliance phase, and ACORE's report offers recommendations to ensure that those processes take advantage of advanced transmission technologies.



A graph from the report showing the costs of reconductoring compared to new transmission build at different voltages. | *ACORE*

Principal Liz Salerno said. "And advanced transmission technologies come right to the rescue here."

GETs and HPCs are mature, proven technologies, and the report's analysis found that they can provide all seven benefits required for consideration under Order 1920, Tsuchida said in a statement.

"Transmission providers can use a holistic evaluation method when assessing various benefits and comparing potential transmission solutions," he added. "These technologies will likely shine through as a lower-cost option to ensuring reliable, affordable power for ratepayers."

Many utilities have not adopted advanced transmission technologies (ATTs) because they are unfamiliar with them, and their investment incentives are not aligned well with the technologies, Tsuchida said.

"There's also the fact that a lot of the cost associated with transmission — for example, if there's an outage, or if there's congestion, or if there's more investment needed — that is passed through to the end-use customers, while the transmission service providers may not necessarily feel that immediately," he said.

Transmission needs are growing rapidly, so much so that the pace of traditional transmission development cannot keep pace. Traditional wire projects can take five to 10 years to develop and are often hindered by regulatory delays, the complexity of interregional coordination, cost allocation and permitting, the paper says.

"Because of the three characteristics discussed above (lower cost and speedier installation, complementarity to existing equipment, and portability and reversibility), ATTs can provide cost-effective solutions in a shorter schedule than relying solely on the traditional wires-based solutions," the report says. "Additionally, the fragmented nature of transmission planning and cost allocation often stalls large projects; HPCs, through reconductoring, can reduce the scope of new upgrades, while GETs can offer incremental upgrades that align with the scenario-based, collaborative approach emphasized in Order 1920."

ATTs need to be used in short- and long-term planning, with the report saying that splitting the various solutions into those two time frames (or even more granular ones) will allow planners to address challenges that span immediate needs and flexible goals.

GETs can provide near-term relief to transmission congestion and improve grid efficiency without the delays of traditional transmission investment. Both GETs and HPCs can help modernize the grid, integrate new technologies, and prepare for future demand and renewable growth in a cost-effective way, the report says.

Order 1920 requires grid planners to consider seven benefits of new transmission, two of which are temporary, such as lowering congestion from outages, and the mitigation of extreme weather events and unexpected system conditions. Assessing their benefits will require planners to consider shorter time frames than normal, the paper says.

"Associated with the new temporal scenarios to analyze, transmission providers will need to develop methodologies on how to consider benefits (and costs) over varying timelines," the report says. "For example, evaluating a potential solution could require analyses over multiple timelines to capture the benefits and associated trade-offs among benefits (a solution could impact several benefits) over different timelines."

Compliance with Order 1920 is proceeding at different paces in some regions, with FERC having granted some extensions. In PJM, Maryland Public Service Commissioner Michael T. Richard said on the webinar that the RTO was working with the states and stakeholders on complying with the new rule.

"I do think we need to make sure this is not going to be just status quo; a new kind of [Regional Transmission Expansion Plan] that is just extended," Richard said. "And in fact, it is going to be a planning opportunity with the states at the center. The core of the plan for the future needs to be how the states envision their resources … and then we can work to make sure that we all have the same goal: keep the lights on."

While compliance is proceeding, GQS Principal and former FERC Chair Richard Glick (who launched the rulemaking process that led to Orders 1920 and 2023) said in a statement that those efforts will take time.

"In the meantime, action is needed to address more immediate threats to reliability and affordability," Glick said. "This report shows that GETs and HPCs offer a near-term capacity solution while grid operators continue to plan the regional transmission lines needed to meet future challenges." ■

Commissioner Willie Phillips Announces his Resignation from FERC

By James Downing

FERC Commissioner Willie Phillips, who chaired the agency for two years, announced April 22 that he was leaving the agency just over a year before his term was set to expire, after pressure to resign from the White House.

In news first reported by POLITICO, the White House asked Phillips to step down. The move gives President Donald Trump the power to nominate a new commissioner, shifting its partisan balance to three Republican appointees and two Democrats, the standard makeup of a fully staffed FERC that gives the party in the White House a majority.

FERC Chair Mark Christie released a statement, noting the two had known each other for years before becoming federal regulators as they both were on state utility commissions that were active in the Organization of PJM States Inc. (OPSI) and at the National Association of Regulatory Utility Commissioners.

"Willie has been a good friend for whom I have tremendous respect and affection," Christie said. "He is a dedicated and selfless public servant. As I have said many times, he did an outstanding job as chairman of FERC. He and I worked together on many contentious issues to find common ground and get things done to serve the public interest. We will miss him here at FERC."

Christie wished Phillips continued success on "whatever career path he chooses" after leaving the commission.

Phillips posted his own *statement* on LinkedIn, saying it was time for to move on after being a regulator for 12 years, which includes his tenure at the D.C. Public Service Commission.

"As my time at FERC comes to a close, I'm proud of all we've accomplished to advance a more reliable and affordable energy future for all Americans," Phillips said. "Our grid faces growing challenges — from surging demand driven by data centers, to resource adequacy, capacity markets and the urgent need for transmission reform. These complex issues demand bold, innovative solutions, and I look forward to continuing to work on them in the next chapter of my journey."

The other three FERC commissioners all released statements praising Phillips for his work on the commission, but his departure was criticized by longtime agency watcher and Public Citizen Energy Director Tyson Slocum.

FERC Commissioner Willie Phillips | © *RTO Insider*

"Commissioner Phillips' decision to voluntarily leave his seat a year early hands control of FERC to the White House, where Trump's radical plans to abuse national security and emergency powers will now likely no longer feature meaningful FERC opposition," Slocum said. "Phillips had an opportunity to ensure an independent check on Trump's abuses, but he apparently decided he has better things to do than ensure the public interest is protected."

While the president can name the chair at FERC, current legal precedent holds that commissioners can be fired only for cause.

The chairs of other regulatory agencies that fall under that precedent, including the *Securities and Exchange Commission*, the *Federal Communications Commission* and the Federal Trade Commission, all stepped down when Trump took office this January. The chair stepping down if the opposite party won the presidential election used to be the norm at FERC, but it started breaking down before Trump took office in 2017.

A spat between President Obama and the Senate Energy and Natural Resources Committee left FERC with only three Democratic members when Trump took office and without a quorum when he demoted Norman Bay from chair, who resigned in response. Then after President Joe Biden took office, two of Trump's former chairs — Neil Chatterjee and James Danly — both served out their full terms.

Chatterjee *posted* on X when the news broke that Phillips' departure was disappointing, and he noted that the differences between commissioners at FERC usually are not partisan. Phillips pushed through new LNG export facilities when the Biden White House issued a pause on approvals from the Department of Energy, and he was the lone dissenter on a data center co-location deal last year when Republican colleagues voted to deny it. (See *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.)

FTC Chair Lina Khan stepped down in January, but last month, Trump fired two other Democratic appointees to the agency who are challenging that in court.

Speaking at the Colorado Legislature in March shortly after Trump fired him, FTC Commissioner Alvaro Bedoya said he was not focused on the status of the law, or respect for Supreme Court precedents.

"I think we need to be focused on the billionaires over President Trump's shoulder at his inauguration, and what this attempt will do for them," Bedoya said. "Because I think above all else, we need to be asking ourselves, who will win from this attempt to illegally remove us?"

Those included big tech executives like Tesla and X's Elon Musk, Meta's Mark Zuckerberg and Amazon's Jeff Bezos, all of whom were subject to court orders or litigation from FTC cases, he added.

Trump has not made any moves on the two Democrats left on FERC, and doing so now would leave the agency without a quorum and unable to move on key policy priorities like ensuring data centers can reliably connect to the power grid or expanding LNG exports.

"What could happen is that if the president has the authority to remove members of the FTC, I would think there is nothing that would constrain the president from moving members of FERC if the president so desired," former Chair Bay said at the WIRES Group Spring Meeting on April 3.

Bay also made the point that when he was on the agency, the split votes were more likely to happen between Democrats than across party lines.

"That was the world I came from, but I think that was really important for FERC authority, for its legitimacy, for the regulatory stability and certainty provided to industry," Bay said. "And, so, what I hope does not happen at FERC is that you get a revolving door of commissioners based upon changes in presidential administrations." ■

Oregon House Passes Bill to Shift Energy Costs onto Data Centers

Legislation Would Impose Contractual Obligations on Large Energy Users

By Henrik Nilsson

The Oregon House of Representatives has approved a bill that would require data center developers to shoulder a larger share of their own energy costs in an effort to mitigate risk to smaller consumers.

House Bill 3546, or the POWER Act, passed in a 41-16 vote on April 22. It empowers the Oregon Public Utility Commission to create a separate customer category for large energy users, such as data centers, and requires those users to pay a proportionate share of their infrastructure and energy costs.

The legislation now moves to the state Senate.

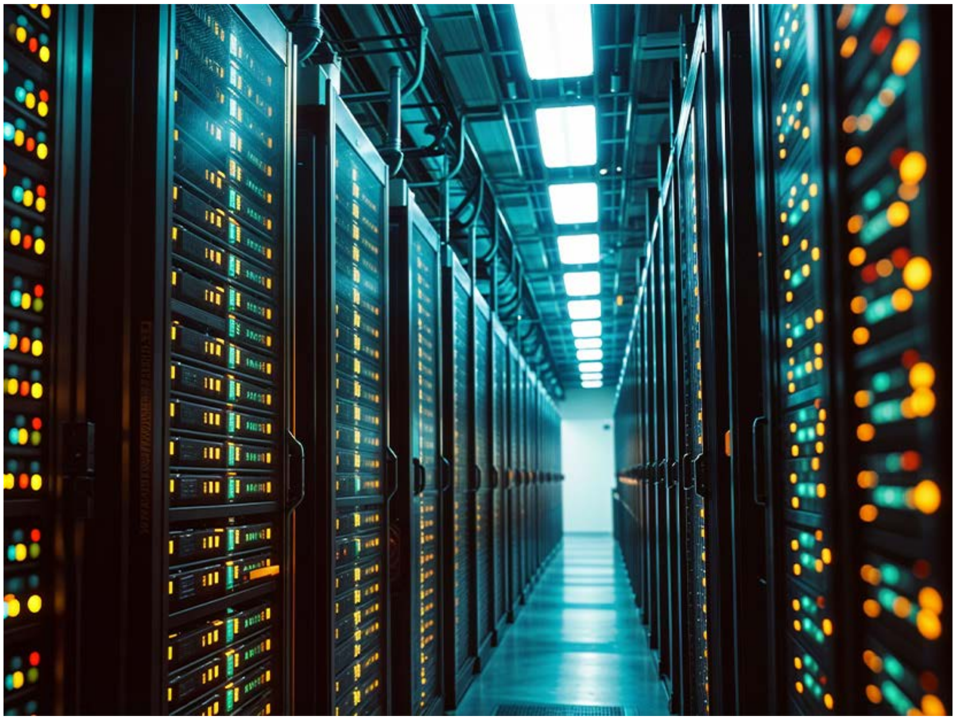
Rep. Pam Marsh (D), one of the bill's chief sponsors, said the "explosion of huge technology facilities has upended" the traditional idea of distributing energy demand costs equally among consumers.

"Since 2019, data center growth in [the Portland General Electric] territory has been equivalent to an increase of 400,000 residential customers, but residential demand has actually grown by only 63,000 people, or 24,000 customer accounts," according to Marsh. "Without intervention, the cost created by the disproportionate demand of big energy users will be borne by residential and small business consumers who are already struggling."

The bill defines a large energy use facility as one that uses more than 20 MW. The law would only apply to Oregon's investor-owned utilities.

Additionally, under the bill, data centers must sign contracts for at least 10 years with energy companies to protect energy infrastructure investments. The contract requires the data center operators to pay for a minimum amount of energy based on the center's expected energy usage during the contract period, and "[m]ay include a charge for excess demand that is in addition to the tariff schedule," according to the bill.

"If a utility is going to make investments to serve a large user, we need some assurances that those investments do not become a stranded asset that is essentially shifted to other ratepayers," Marsh said.



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Why This Matters

Legislators and regulators around the country are wrestling with the same question: who pays for the energy infrastructure as demand skyrockets, and will the data center industry pay its 'full cost of service?'

The bill also requires the Oregon PUC to provide the legislature with reports detailing trends in load requirements.

Kandi Young, a spokesperson for the PUC, told *RTO Insider* that the commission "appreciates the legislature's recognition of the challenges new large loads can present to utilities and their customers. The PUC is already working to help ensure that other electricity customers do not inappropriately pay for the costs to serve these large users of electricity and will work with stakeholders from all perspectives to implement additional policy direction on this issue should the bill be signed into law."

Pacific Power spokesperson Simon Gutierrez said the utility, a subsidiary of PacifiCorp, "supports HB 3546 as a meaningful framework to ensure continued economic growth with fairness for all customers."

"While the existing regulatory framework is established to protect customers and align the costs of energy infrastructure with the customers benefiting from these investments, the scale, pace and uncertainty surrounding this potential load growth [require] additional regulatory updates to protect all customers while creating a path for large customers to expand their businesses," he said.

Organizations like the Northwest Energy

Coalition, BlueGreen Alliance and Sierra Club have supported the bill.

'Disparate Rate Treatment'

The bill also faced opposition. Republican Rep. Bobby Levy called it a "regulatory overreach."

Data centers are "legally operating businesses already regulated under existing PUC authority, and they provide critical infrastructure, jobs [and] economic development, especially in rural areas," Levy said. "Under this bill, they would face entirely separate tariff schedules, new reporting burdens and regulatory uncertainty, not because they've done anything wrong but because they've grown and used power efficiently."

Writing in opposition to the bill in March, the Data Center Coalition, a membership association, said it "supports the underlying intent of HB 3546, and the data center industry is committed to paying its full cost of service."

But "no customer, industry or class should be singled out for differential or disparate rate treatment unless that approach is backed by verifiable cost-based reasoning," DCC wrote. "Data centers are but one large end user of electric utilities and part of a larger portfolio of end users driving increased electricity demand. Any rate design that focuses on a single end use, without showing a measurable difference in service requirements or cost responsibility, risks creating unjustified distinctions among similar customers."

Shannon Kellogg, vice president of public policy at Amazon Web Services, which has been operating data centers in Eastern Oregon since 2011, provided neutral testimony, writing that "a significant bottleneck to bringing new carbon-free energy projects online is the interconnection process to the grid."

"To unlock these projects, it is important for transmission infrastructure and regional energy systems to modernize and expand quickly, and we are working closely with lawmakers and regulators to accelerate these changes," Kellogg wrote.

The proposed legislation comes as data center growth in Oregon has increased rapidly. The amount of data centers seeking service "is unprecedented," according to an Oregon Citizens' Utility Board *presentation*.

In December 2024, WECC predicted that annual demand in the Western Interconnection would grow from 942 TWh in 2025 to 1,134 TWh in 2034. That 20.4% increase is more than four times the 4.5% growth rate from 2013 to 2022 and double the 9.6% growth forecast in 2022 resource plans. (See *West to See 'Staggering' Load Growth, WECC Report Says*.)

Similarly, the Pacific Northwest Utilities Conference Committee's Northwest regional forecast for 2024 found that electricity demand would increase from about 23,700 average MW in 2024 to about 31,100 aMW in 2033, an increase of more than 30% in the next 10 years.

In February, Washington Gov. Bob Ferguson directed three state agencies, electric utilities and other groups to collaborate in developing a report recommending policies for addressing data center energy use. (See *Wash. Governor Orders Study to Explore Data Center Impact*.) ■

APS to Keep Cholla Plant Closed Despite Trump Order Backing Coal

Springerville Coal Units Also on Track for Scheduled Closures, TEP Tells Arizona Regulators

By Elaine Goodman

APS' coal-fired Cholla power plant | *Center for Land Use Interpretation*

Arizona Public Service (APS) officials said they're looking to a non-coal future for the recently closed Cholla coal-fired power plant, despite President Donald Trump's calls to keep the facility running.

APS discussed the Cholla power plant April 24 during a summer preparedness workshop hosted by the Arizona Corporation Commission. APS stopped running the Cholla plant on March 17.

Jeff Allmon, associate general counsel with APS parent Pinnacle West Capital, said the utility started planning for the closure more than 10 years ago, when APS made a deal to keep the plant running until 2025 without "very expensive" pollution control equipment. Without the agreement, the pollution-control equipment would have been required by 2017 to comply with EPA's regional haze regulations, Allmon said.

To keep Cholla running long-term as a coal-fired plant, pollution controls now would be needed.

"And those would be of a significant scale — selective catalytic reduction — which would come at a significant cost to our customers," Allmon said.

And because APS had been planning a "phasedown" of the facility, capital investments and deferred maintenance would be necessary for safe and reliable long-term operation, he added.

Allmon said APS was preserving infrastructure at the plant, which is being eyed as a potential site for nuclear power.

"[While] all options are on the table, including gas, the nuclear generation option is really the one that we think offers the most promise," he said.

After the workshop, ACC Chair Kevin Thompson and Vice Chair Nick Myers issued statements that highlighted the impacts to ratepayers of keeping the Cholla power plant running.

"Trying to reopen Cholla at this point would result in significantly higher rates for customers," Myers said. "The utilities have already been planning for this retirement, and replacement costs are already being borne by the utility customers."

"Bringing the Cholla plant into compliance with Obama-era EPA requirements will require the installation of costly scrubbers on the coal-fired units that would cost ratepayers hundreds of millions of dollars," Thompson said.

On April 8, Trump signed a series of executive orders aimed at keeping existing coal-fired power plants running, removing state laws that hinder the industry, and easing regulations and permitting for coal mining. (See *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

During a signing ceremony for the executive orders, Trump instructed Energy Secretary Chris Wright to save the Cholla coal plant in Arizona.

Why This Matters

The commitment by Arizona utilities to stay the course on plant closures sends a strong signal that President Trump's executive order will do little to support the prospects for coal-fired generation.

Peak Load Record

APS hit a record peak load of 8,210 MW in 2024, a year in which Phoenix experienced a record-breaking heat wave. That followed a peak load of 8,162 MW in 2023, which was a record for APS at the time, according to Tim Rusert, APS's director of power supply services.

For 2025, APS is adding about 1,550 MW of solar-plus-storage or standalone storage through power purchase agreements, Rusert said during the ACC summer preparedness workshop.

Rusert said APS will dispatch over 2,100 MW of battery storage this summer, compared to the 600 MW it had last year.

"We're confident in this battery storage because … we've had a lot of experience working with it," Rusert said. "It's a dependable resource. It's quick reacting. With effective planning, it's there when you need it."

Also during the ACC workshop, Tucson Electric Power (TEP) representatives said the company will retire units 1 and 2 at the coal-fired Springerville power plant in 2027 and 2032, respectively. TEP is exploring whether it can repurpose the Springerville plant for nuclear or gas generation. ■

Calif. Lawmakers to Discuss Amendment Requests to Pathways Bill

TURN's Opposition to Bill to Alter CAISO Governance is Finding Listeners

By Henrik Nilsson

The Utility Reform Network (TURN) is finding some success in getting California state lawmakers to address the group's concerns about what the Trump administration might do if the Golden State moves forward with plans to hand over control of CAISO's energy markets to an independent regional organization.

Democratic Sen. Josh Becker, who introduced the Pathways bill, has said he will convene a group to address the consumer advocacy organization TURN's concerns with the proposed legislation. In its public comments on the bill, TURN submitted a *position of opposition* that stands unless the bill is amended.

Kathleen Staks, executive director of Western Freedom and the co-chair of the West-Wide Governance Pathways Initiative's Launch Committee, provided the update during the committee's monthly meeting April 25.

Staks said there has been no commitment to addressing all of TURN's requests for amendments.

"I think we have to figure out as a group, how do we continue to honor the recommendation that … came out of the Launch Committee, ensure that whatever recommended amendments are something that our coalition can continue to live with," Staks said.

Senate Bill 540, or the Pathways bill, is the product of the work of the Pathways Initiative, the nearly two-year effort to support the expansion of CAISO's Western Energy Imbalance Market (WEIM) and soon-to-be-implemented Extended Day-Ahead Market (EDAM) to entities outside California by shifting governance of the markets from the ISO to a proposed independent RO.

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Writing in opposition to the bill, Matthew Freedman, staff attorney for TURN, wrote that handing power over CAISO's wholesale energy markets to an independent RO while opening the door to other market actors in the West "may expose California customers to new risks that could prove difficult to mitigate."

In an email to *RTO Insider*, Freedman said: "Our goal is to ensure that the scope and role of Regional Organization is clearly defined in state law and that California has the right to withdraw under a variety of circumstances. We are extremely concerned about the potential for the federal government to make changes to the regional energy markets that would undermine California's clean energy and decarbonization goals."

The group asked for amendments to address the following points:

- Ensure the RO's tariffs permit California to withdraw utilities from the regional market without penalties or need for approval by FERC.
- Clarify that the RO cannot set "any requirements relating to resource adequacy, reserve margins or reliability." Additionally, the RO should not be allowed to rely on a centralized capacity market or separate markets for dispatchable, firm and intermittent resources. This is to prevent the federal government from intervening in wholesale markets to provide incentives for coal and gas generation.
- Give the California Public Utilities Commission power to direct investor-owned utilities to withdraw from the RO if it violates any of the obligations under SB 540 or implements changes that could harm consumers.
- Require utilities to withdraw from the RO if a court rules that California resource planning policies discriminate against out-of-state resources.
- Similarly, utilities must withdraw if the federal government takes action that would lead to California consumers subsidizing fossil fuels.
- Require utilities to withdraw "if a Joint Concurrent resolution is passed by the State Assembly and State Senate."
- Clarify that the Renewables Portfolio Standard "requirements relating to energy delivery from resources outside of a California Balancing Authority must satisfy strict standards including the use of dynamic scheduling, pseudo ties or firm transmission rights."

Why This Matters

TURN's opposition to the Pathways bill as currently written could complicate passage of the legislation needed to bring independent governance to CAISO's markets.

Staks noted during the April 25 meeting that participation in the market is voluntary, and participants can withdraw "if something does not work for them."

The Pathways bill passed California's Senate Energy, Utilities and Communications Committee unanimously April 21. Though the committee voted in favor of the legislation, some lawmakers referenced TURN's letter, saying they are concerned about whether the bill contains sufficient consumer protections. (See related story, *Calif. Senate Committee Backs Pathways Initiative Bill*.)

The bill will go to the Senate Judiciary Committee for a hearing April 29. But TURN's request for amendments will not be completed before then, according to Randy Howard, general manager of the Northern California Power Agency and Launch Committee member.

"We're still working on dates to try to get the group together face to face," Howard said during the meeting. ■

Calif. Senate Committee Backs Pathways Initiative Bill

Legislation Now Moves to Senate's Judiciary Committee

By Henrik Nilsson

A California state Senate committee voted unanimously in favor of the Pathways bill, bringing the Golden State closer to allowing CAISO to cede oversight of its energy markets to an independent regional organization (RO).

Members of the state Senate Energy, Utilities and Communications Committee on April 21 voted 17-0 in favor of *Senate Bill 540*, dubbed "Pathways," sending the proposed legislation to the Senate Judiciary Committee for a hearing April 29.

The bill is the product of the work of the West-Wide Governance Pathways Initiative, the nearly two-year effort to support the expansion of CAISO's Western Energy Imbalance Market (WEIM) and soon-to-be-implemented Extended Day-Ahead Market (EDAM) to entities outside California by shifting governance of the markets from the ISO to a proposed independent RO.

Democratic Sens. Henry Stern and Josh Becker introduced the bill in February. During the April 21 hearing, Becker noted that the legislation comes as SPP prepares to launch its own day-ahead market, Markets+, which has already attracted participants. (See *Pathways 'Step 2' Bill Introduced in Calif. Legislature*.)

"Why do we need to do this now? The urgency is that if we don't act quickly, we risk having less ability to trade with other regions and impact the clean energy resources available across the West," Becker said. "Regions are getting tired of waiting for us and are considering joining Southwest Power Pool's Markets+. If they do, they will stop trading with California and also in this WEIM I mentioned earlier, and have less need to make other bilateral trades with California."

Why This Matters

The vote marks a significant step in the Pathways initiative's effort to transfer the governance of CAISO's Western Energy Markets to an independent 'regional organization.'

Becker said participation in the RO is voluntary, adding that California retains its right to set its own energy policy goals and doesn't have to join unless "specific, stringent guardrails are met."

Reached for comment about Becker's statement, SPP spokesperson Derek Wingfield told *RTO Insider*: "Markets+ creates additional opportunities for Western entities and will not inhibit trade among them, including entities in California."

Stern, meanwhile, contended that Pathways would allow California to tap into a wider market of clean energy resources, saying "if we don't reach beyond our borders and allow for other cleaner renewables to be able to come in and balance our grid depending on the time of day, we're gonna have to find that power somewhere. And right now, we are literally paying for it, and we're not just paying for it with taxpayer dollars, but it's in our lungs, it's in environmental injustices everywhere."

Representatives from the International Brotherhood of Electrical Workers, Natural Resources Defense Council, Environmental Defense Fund and others supported the bill during the hearing.

Opposition, Concerns

However, lawmakers also heard from opponents, including the Center for Biological Diversity, the California Solar & Storage Association and Californians for Green Nuclear Power.

Bill Julian, former legislative director of the California Public Utilities Commission, opposed the bill on behalf of himself and former CPUC President, Loretta Lynch.

Lynch, in a previous meeting, contended that many of the arguments favoring Pathways rely on hypothetical scenarios in which EDAM would consist of participants from all Western states. This is unlikely, Lynch said, noting that several entities already have decided not to join EDAM. (See *Pathways Initiative Receives Praise, Skepticism at Calif. Hearing*.)

California lawmakers voted unanimously in favor of the Pathways bill on April 21. | *Shutterstock*

Though the committee voted unanimously to pass the legislation, some lawmakers voiced concern about the lack of certain provisions in the bill.

For example, Democratic Sens. Benjamin Allen and Aisha Wahab expressed concern about California's ability to withdraw from the RO under the legislation.

Allen pointed to comments by groups like The Utility Reform Network (TURN) that have argued the bill's language is not strong enough to protect from the risk of penalties against the state or utilities if California withdraws.

Committee member Susan Rubio urged Becker to explore further consumer protections.

Becker noted that the groups behind the bill are looking at amendments and plan to move forward with some suggestions, even some from opposing parties like Lynch.

"Certainly, you have my commitment to work with you and make sure that by the end of this process there's a bill that we're all comfortable with," Becker said. "And then, as just a reminder, we'll have at least two years with the legislature able to weigh in before we join."

The Pathways bill states that CAISO can decide whether to join the RO-governed market on or after Jan. 1, 2027. ■

Consumers Defend Local Transmission Planning Complaint from Protests

By James Downing

Consumer groups defended their complaint with FERC alleging utilities were spending too much on lightly regulated local transmission projects against arguments that such spending is justified (*EL25-44*).

In a joint answer to protests filed April 24, the 22 groups — including the Industrial Energy Consumers of America, American Forest & Paper Association and R Street Institute — argued that the December 2024 complaint against all FERC-jurisdictional transmission planners should be granted so the commission can address what they called widespread unjust and unreasonable planning practices. (See *Utilities Ask FERC to Toss Local Tx Planning Complaint, Others Support It*.)

While the transmission lines can be called "local," those at issue in the complaint are in the Eastern and Western Interconnections and are part of interstate commerce. That has long been recognized by the courts, the groups said.

"Respondents nevertheless insist that planning of interstate transmission at the individual level remains appropriate because such transmission is 'local' and that existing transmission owners have a 'right' to plan the interconnected grid of the future simply because they built the grid of yesterday," they said. "Respondents make no electrical distinction between local and regional transmission."

The actual difference between "local" and "regional" projects can be arbitrary, the groups argued, noting as an example that American Transmission Co. independently started planning a 345-kV line, which was then selected by MISO for its regional transmission plan, with its costs spread across the footprint.

"ATC argues that 'the project directly contradicts the "piecemeal planning" allegations contained within the complaint,' but the project actually proves the point of the complaint, as MISO recognized that the project impacted the entire region, although it was initially individually planned," the consumer groups said. "The electrical nature of the project did not change through the regional review, and the complaint identified hundreds of similar projects that were individually planned with no substantive regional review."

| © RTO Insider

Why This Matters

How FERC rules on the complaint could set a precedent on what the commission considers 'local' transmission planning, compared to what is regional.

A common rebuttal to the complaint was that utilities had to retain their planning role to effectively meet state retail obligations, which leaves it outside of FERC jurisdiction.

"The complaint is based on the simple electrical premise that there is no FERC-jurisdictional 'local' transmission and thus there are no 'local' transmission planning needs," the groups responded. "There are localized inputs to determining the holistic needs of the interconnected grid, but electrical facilities at 100 kV and above are not local, except those excluded by the complaint."

Local projects that solely serve intrastate needs are outside of FERC jurisdiction, and the complaint does not ask FERC to try to regulate them.

Many protesters argued that the complaint is too broad, and the commission should take regional differences into account if it decides to grant it.

"Individual or even regional 'planning challenges' or differences are irrelevant to the fundamental question under the complaint as to whether it is appropriate to allow individual transmission owners to plan 100-kV and above transmission in interstate commerce based on the ongoing false premise that such transmission planning relates to 'local transmission,'" the groups answered. "Planning challenges, to the extent they exist, can be incorporated into the required regional planning, just as regional differences are incorporated today in regional planning." FERC can grant the complaint and facilitate implementation of any necessary region-specific reforms through compliance filings, they argued.

Another common rebuttal was that the complaint had to prove that local planning leads to unjust and unreasonable rates on specific projects, but the groups argued it was aimed at local planning practices and that Section 206 of the Federal Power Act can address broad industry practices.

"Critically, acceptance of respondents' arguments would also mean that FERC, under a rulemaking pursuant to Section 206, wouldn't be able to dictate nationwide standards, like in Orders Nos. 890, 1000 [and] 1920," they said.

Opponents also argued that the complaint was a collateral attack on Order 1920, or even earlier transmission planning rules, but the groups said they had put new evidence in front of FERC that it did not have during the proceedings that led to its most recent transmission planning rule.

"The new evidence and changed circumstances consist of new analytical reports and evidence of both individual projects and cumulative regional transmission plans and portfolios across every planning region over several years," they said.

Other Parties Defend the Complaint

American Municipal Power also filed an answer April 24, arguing FERC should grant the complaint despite a request from PJM and its transmission owners to dismiss it.

The complaint made the case that spending on local projects in PJM has become unjust and unreasonable and should be dealt with in a subsequent show-cause proceeding, AMP said.

Transmission rates in PJM are up 237% from 2011, mainly from local projects with limited oversight, AMP said.

"Forcing local transmission customers to bear the cost of projects that should have been supplanted by more cost-effective regional projects could unduly discriminate against those local customers by unfairly shifting the cost of transmission projects in a manner inconsistent with cost-causation principles," AMP said. "The harmful effect of these failures would only multiply going forward, as PJM's load is expected to grow by 70 GW or more in the foreseeable future."

The Maine Public Utilities Commission similarly rebutted claims about local planning in New England. It said FERC should open another Section 206 show-cause proceeding so it can address the issues around local planning and its lack of oversight in New England.

Projects above $5 million are presented to ISO-NE's Planning Advisory Committee, but the process has proven inadequate, and the TOs retain all control over asset-condition projects in the region.

The PUC "completely agrees that the ISO-NE tariff and related documents do not provide ISO-NE with a role in local transmission planning sufficient to effectuate all of the remedies sought by complainants, but [it] submits that a Section 206 investigation will allow parties to build a record upon which remedies consistent with Order No. 890 and FERC precedent may be developed specifically for the New England region," it said. ■

CPUC, Others Question Details of EDAM Congestion Revenue Proposal

What Will be Real Effects on Market Participants, They Asked

By David Krause

Stakeholders and state energy officials continue to raise concerns about a CAISO draft proposal that would adjust how congestion revenues are allocated in its Extended Day-Ahead Market, with the ISO aiming for a vote on the final proposal in the coming weeks.

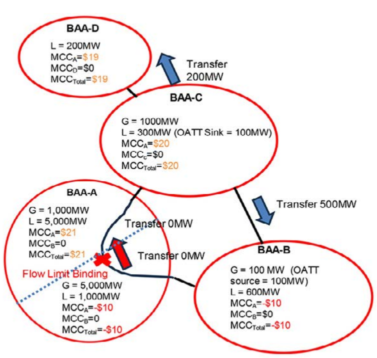
The draft proposal, released *last week*, addresses how the EDAM will allocate congestion revenues when a transmission constraint in one EDAM balancing authority area causes parallel flows in a neighboring BAA.

CAISO has said the draft proposal will be "transitional" over the next three years, after which time it plans to implement a more permanent design.

The proposal is a product of the past two months of focused work on the subject. In March, CAISO launched an expedited initiative to address stakeholder concerns, and this week, the agency held an all-day meeting to review the proposal with the more than 150 participants who joined the call.

At the April 24 meeting, California Public Utilities Commission regulatory analyst Michele Kito asked if the ISO had a sense of where the major parallel flows currently take place on the system.

"I would imagine that we can look at historical system data," Kito said. "Do we have any sense of what those [parallel flows] are and what the effects each of these proposals have in terms of revenue allocation?"



An example of the complexity of counterflow market awards and settlement under the draft proposal design | *CAISO*

"We haven't looked at specific parallel flow impacts," George Angelidis, CAISO executive principal, said at the meeting. "There are well-known transmission bottlenecks in the ISO system, like Path 36 and Path 15, but in general, any kind of flow in the system will experience what we define as parallel flow."

Parallel flow is the impact on the flow gauge of transactions that are external to that BAA, Angelidis said. They can be infinite: Any path will have parallel flows, so CAISO has not looked at potential parallel flow results on specific flow gauges, he said.

Cathleen Colbert, senior director of Western markets policy at Vistra, added, "I will give a little extra support to Michele's questions. Do we not have any sense of how these parallel flows work on internal constraints? I do think there's a case for you guys to provide some additional kind of forward-looking information."

CAISO will be studying these parallel flow effects over the three-year period of the new design, said Milos Bosanac, ISO regional markets sector manager.

"As entities join the EDAM, we will be modeling transmission constraints on their system that may not necessarily be reflective today," Bosanac said. "I think it's difficult to surmise the effects at this point in time of constraints that might not yet be modeled. [However], we will be modeling the new design on PacifiCorp's system, and as other entities join, we will model those effects [too]."

Middle Approach

Under current EDAM market rules, Open Access Transmission Tariff (OATT) customers in one BAA will end up paying costs for congestion for parallel flows caused by binding transmission constraints in neighboring BAAs. However, under the draft final proposal, parallel flow congestion revenues collected in a BAA that result from a binding constraint in a neighboring area will first be allocated to the BAA in which the overflow congestion occurs and the revenues are collected.

> **Why This Matters**
>
> The CPUC's questions to CAISO show the agency will be carefully scrutinizing the proposed EDAM congestion revenue design to ensure California's interests aren't overlooked in the plan.

In an example reviewed at the meeting, \$135,800 in congestion revenue was collected and distributed to three balancing areas: BAA A, BAA B and BAA C. Under the current design, all \$135,800 would be distributed to BAA A. However, under the draft proposal, BAA A would receive \$132,800 in revenue, BAA B would receive \$1,000, and BAA C would receive \$2,000.

The final draft proposal supports EDAM entities' capacity to provide congestion cost protection for transmission customers exercising firm OATT rights, Bosanac said. The draft also addresses stakeholder concerns about a balancing area being exposed to congestion costs when providing counterflow effects in relation to constraints, he said.

The draft would apply only to the day-ahead market, not to the real-time market. The real-time market retains the congestion revenue allocation in effect today in the WEIM "in order to minimize the impact on the WEIM participants," Bosanac said.

If approved, CAISO will implement the draft final proposal by collecting data and monitoring the congestion effects over the first one to two years of the transitional approach. CAISO will then prepare a permanent design after the three-year period. ■

Texas PUC Approves 765-kV Transmission Option for Permian Basin

Commission: Higher-voltage Lines' Benefits Outweigh Costs

By Tom Kleckner

Why This Matters

The three 765-kV import paths into the oil-rich Permian Basin are more expensive than the alternative five 345-kV lines, but the PUC said the long-term benefits outweigh the costs.

In what is being labeled a "landmark" and "historic" decision by the industry, the Texas Public Utility Commission approved a plan April 24 that allows ERCOT to authorize the region's first extra-high-voltage transmission lines and meet the petroleum-rich Permian Basin's rapidly growing power needs.

The PUC unanimously endorsed staff's recommendation to construct three 765-kV import paths into the Permian Basin, where oil and gas electrification and data center announcements have significantly increased load projections. The 765-kV option, while 22% more expensive than the 345-kV option, will carry more than twice the voltage of existing infrastructure. (See *PUC Staff Urges Approval of 765-kV Lines to West Texas*.)

ERCOT and the transmission service providers (TSPs) have said the 765-kV lines can carry more power and meet higher demand levels as the state continues to grow. They can reduce congestion on existing transmission lines and could save money in the long term by eliminating the need to build additional lines.

The TSPs have been preparing certificates of convenience and necessity applications for the projects approved in the plan. "Now that the voltage decision [has been] made, they can begin filing those applications to get the process started," spokesperson Ellie Breed said in an email.

"Our priority now is ensuring utilities execute these projects quickly and at the lowest possible cost to Texas consumers," PUC Chair Thomas Gleeson said in a *statement*.

Staff said the current options have increased to $10.11 billion for 765 kV and $8.28 billion for 345 kV.

"This is really exciting for Texas, when you look back on monumental decisions that affect Texas," Commissioner Kathleen Jackson said during the open meeting. "This will fit in those benchmarks, and we will look back and say this was one of those decisions."

The PUC's decision came after a monthslong review process that included three public workshops and three rounds of stakeholder feedback. Commission staff conducted a full analysis of the costs, equipment supply chains and project-completion timelines for both voltage options, gathering input from the public, equipment manufacturers and the transmission companies that will build and operate the new lines.

The commission's order does not apply to ERCOT's plans to add an EHV backbone to the rest of its system. The grid operator said it will work with the PUC and stakeholders to include the higher voltage in its study process.

ERCOT included a 765-kV study as part of its annual *Regional Transmission Plan* (*55718*). (See *765-kV Lines in West Texas Inch Closer to Reality*.)

The Texas Advanced Energy Business Alliance (TAEBA) applauded the PUC's decision, saying in an email the "historic vote" ushers in a "new era of grid modernization for the Lone Star State."

"This decision brings ERCOT into the 21st century," TAEBA Executive Director Matthew Boms said. "As electricity demand surges, we need a grid that's built for the future — reliable, efficient and cost-effective. Today's vote is a strong step toward that goal."

American Electric Power *trumpeted* the fact that its Texas subsidiary will build one of the three import paths into the Permian Basin as part of a jointly assigned project. The 300-mile line will run from Fort Stockton to San Antonio.

AEP energized its first 765-kV operational transmission line in 1969 between Kentucky and Ohio. It now owns 2,110 miles of 765-kV facilities, more than any other system in North America, it said.

The commission also endorsed a *petition* approving assignments to the TSPs to own, construct and operate the Permian Basin projects (*57441*).

"I want to further clarify the commission is not deciding in this proceeding any requirement for a TSP's CCN," Gleeson said. "Those will be decided in the future."

At the PUC's direction, ERCOT filed its *reliability plan* for the Permian Basin in July 2024. The plan included the 345- and 765-kV import paths and a 2038 need date. The commission *approved* the plan in October 2024 but reserved a decision on the voltage level by May. (See *Texas PUC Approves Permian Reliability Plan*.)

4 Projects Added to TEF

The PUC approved *staff's recommendation* to advance four generation projects, totaling more than 1,900 MW of capacity, to the *Texas Energy Fund*'s due diligence review.

The low-interest loan program, designed to add 10 GW in gas generation, has seen eight projects drop out or be removed in recent months (*56896*). (See *2 More Projects Fall out of TEF Loan Program*.)

The projects belong to independent power producers Invenergy and Nightpeak Energy. Invenergy proposed two projects totaling 1,369 MW of capacity, and Nightpeak has applied for loans to cover 565 MW. That raises the TEF In-ERCOT Program portfolio to 18 projects, promising 9,218 MW and requesting $5.04 billion in loans. Texas lawmakers have already set aside $5 billion for the program.

"These are taxpayer dollars, and this is our program. We set the rules, and at the end of the day, you have to have the ability to repay, and you have to have the ability to execute," Gleeson said. "Inherent in getting public funds is a trust from the public that they'll be spent correctly, and I think our due diligence process is helping to ensure that."

The commission also approved the first recipient of the TEF's *Completion Bonus Grant Program*, which awards grants to companies that add at least 100 MW to the ERCOT grid through new construction or by expanding dispatchable generators that meet the TEF's requirements.

The Lower Colorado River Authority is seeking *$22.5 million in loans* to help build the first of two 188-MW gas-fired units at its *Timmerman Power Plant*. The PUC can award LCRA a maximum of $120,000/MW (up to $22.5 million) if the unit connects to ERCOT before June 1, 2026. The facility will be tracked annually for 10 years and must meet specific performance and reliability measures and is available to ERCOT dispatch.

The unit is scheduled to reach commercial operations in 2025.

"It's just good to see LCRA coming forward and taking advantage of this," Jackson said. "It's 10 years of oversight and performance, incentivizing them to be able to get the full grant."

Braunig RMR Work Delayed

ERCOT staff *told* the commission that a crack in Braunig Unit 3's boiler superheater header will require that the header be replaced, "significantly extending" the unit's potential return to service as late as spring 2026 (*55999*).

CPS Energy found the crack during its maintenance outage, which began March 3 as part of the unit's reliability must-run agreement with ERCOT. The San Antonio municipality announced in 2024 it would be retiring the 55-year-old gas unit along with Braunig's other two units, but the Texas grid operator said it was still needed for reliability reasons. (See "RMR Contract for CPS Energy Unit Faces Increased Costs, Delays," *ERCOT Board of Directors Briefs: April 7-8, 2025*.)

David Kezell, ERCOT's director of weatherization and inspection, said a new superheater will have to be built specifically for Braunig 3. Ideally, he said, the unit could be operational for the 2025/26 winter. The superheater is expected to cost about $3 million but is within the outage's current $25 million budget, Kezell said.

"The budget is in reasonable shape," he said.

ERCOT and the market already are on the hook for $45.85 million under the terms of Braunig 3's RMR.

Kristi Hobbs, vice president of system planning and weatherization, said ERCOT conducted another analysis to determine whether to proceed with the investment in Braunig. Staff updated their models with load growth and generation studies since their previous study and came to the same result.

"We found that even with a delay, even if it's delayed into February of next year, there is still more benefit than cost to moving forward with maintaining the Braunig unit," Hobbs said. "We see the potential benefit really comes next summer in the July and August time frame … so we still see that benefit of moving forward with the work."

ERCOT counsel Nathan Bigbee told the PUC that ERCOT had reached an agreement with LifeCycle Power, which owns 15 mobile generators that it has leased to CenterPoint Energy, and is proceeding with plans to move the units to San Antonio over the summer. He said cooperation is still needed between CenterPoint and CPS to "make this all work."

"Having a fundamental structure in place for ERCOT and the LifeCycle arrangement will help facilitate those agreements as well," Bigbee said. "This is not like anything else we've had before. We are leveraging the RMR framework for the dispatch, the settlement and the performance metrics for these generators."

The generators, which can produce nearly 40 MW apiece, will be moved to San Antonio in groups of three. They will then be connected in strategic sites to the CPS distribution network.

In other actions that the PUC crammed into just over an hour before adjourning, the commissioners:

- sided with *staff's recommendation* to delay the first procurement for the proposed *firm fuel supply service* (FFSS) until the 2026/27 winter season. The generation service is still going through ERCOT's stakeholder process; staff were also leery of "competing interests" coming out of the Texas Legislature, which ends in early June (*56000*).

Texas PUC Commissioner Courtney Hjaltman shares her thoughts on the 765-kV proposal. | *Admin Monitor*

- approved a joint application by CPS and South Texas Electric Cooperative for certificates of convenience and necessity for a proposed 345-kV project south of San Antonio. The PUC modified the *proposed order* by changing the project's route, which is estimated to cost between $274 million and $390 million. The project is one of several that are part of the San Antonio South Reliability Project addressing a transmission constraint that led to the Braunig RMR. It will be built and owned 50/50 by CPS and STEC (*57115*).
- accepted CenterPoint's request to recover more than $400 million in restoration costs from a series of storms in May 2024. The PUC approved $28.9 million in restoration costs and an additional $396.3 million in expenses to be securitized (*57271*). (See *Texas Public Utility Commission Briefs: May 23, 2024*.)
- agreed to AEP Texas' $318 million, three-year *system reliability plan* that the company says will save about $71 million in projected restoration costs. About 80% of the plan involves replacing aging infrastructure with newer equipment designed to a higher standard that can better withstand extreme weather events, AEP *said* (*57057*).
- welcomed the city of Caldwell, between Houston and Austin, into the ERCOT system by approving an *order* integrating its 14 MW of load from MISO. The city reached an unopposed agreement with PUC staff, LCRA Transmission Services, Entergy Texas and the Office of Public Utility Counsel. ERCOT did not oppose the settlement (*56164*). ■

Ontario Introducing Nodal Market May 1

Move to Single Schedule System Expected to Save $700M over 10 Years

By Rich Heidorn Jr.

After nine years of development and dozens of stakeholder meetings, the Independent Electricity System Operator (IESO) is poised to launch its new nodal market May 1, a change it says will save Ontario $700 million over the next decade through reduced out-of-market payments and increased efficiency.

The *Market Renewal Program* (MPR) is intended to improve the way IESO supplies, schedules and prices power by creating a financially binding day-ahead market (DAM) and creating almost 1,000 locational marginal pricing (LMP) nodes.

The IESO says nodal pricing — which is used in all seven U.S. RTOs and ISOs — is crucial to efficiently dispatching and providing market signals to renewables and new resource types such as distributed energy resources, storage and hybrids.

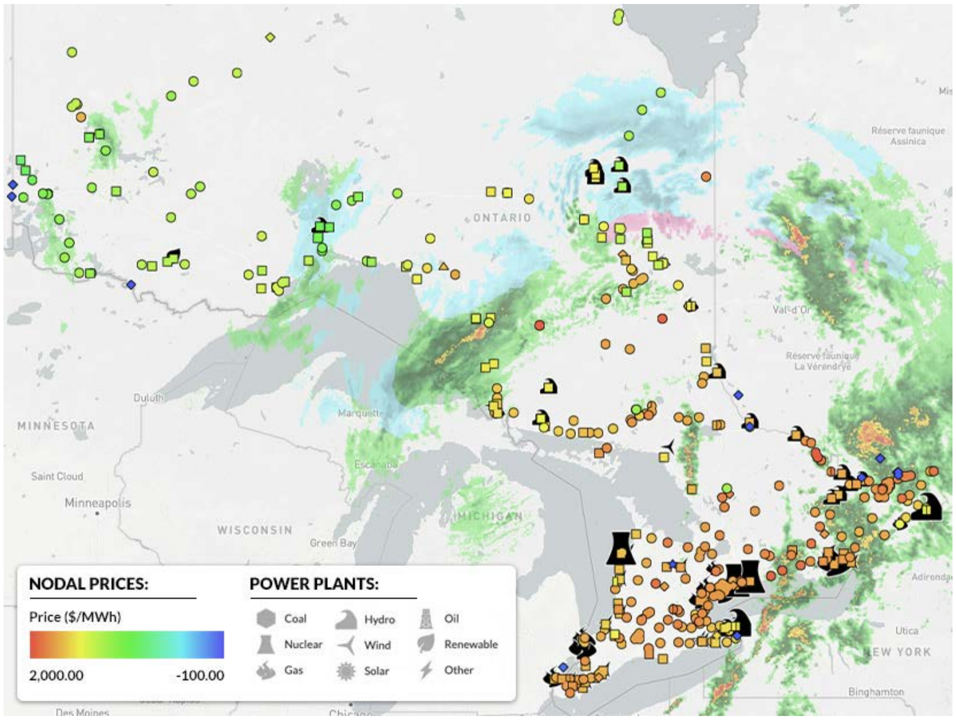
The current day-ahead commitment process is not financially binding, resulting in uncertainty for generators. The addition of a financially binding day-ahead market gives resources "much more certainty over what they will be paid, and it gives us much more certainty over what's available and how we can schedule and commit those resources," said Candice Trickey, director of the MRP, at an April 16 webinar attended by almost 600 people. "So, it gives much, much more clarity, transparency and certainty for both sides."

Under Ontario's current two-schedule market design, the initial schedule ignores system constraints and transmission losses to calculate the Hourly Ontario Energy Price. The second schedule incorporates transmission constraints to determine system dispatch, with uplift payments used to address differences between the two schedules.

The new market will use a single schedule to dispatch the system and calculate LMPs at more than 970 generation, load and intertie nodes in the day-ahead and real-time markets, a number IESO says may increase as its system grows. The day-ahead market will have hourly pricing while the real-time market will continue to price in five-minute increments.

IESO says the improved price transparency should increase efficiency and lower costs.

The pricing granularity is "really important to sort of underpinning all of the changes that we're making and giving us the ability to make those cost decisions, and it will also provide longer-term signals for resources across the province in terms of where it makes the most sense to locate if you're looking for future opportunities," Trickey said. "It will also help better inform consumption decisions for loads that want to be responsive to price."



IESO will begin pricing at almost 1,000 generation, load and intertie nodes May 1. | *Yes Energy*

Why This Matters

Ontario's current system is inefficient at selecting least-cost resources and leads to excessive uplift costs. The new nodal market will put IESO in line with practices at all seven U.S. organized markets.

Work Began in 2016

Work on the new design began in 2016, when IESO held a series of consultations with stakeholders. "Stakeholders have been a big part of this all along the way [with] literally hundreds of meetings covering all kinds of topics — committees, groups, working groups, you name it," Trickey said.

The goal? "Making sure that we make the most of Ontario's electricity supply resources — those that we have today and those that we know are coming in the future," Trickey said. "It's really about improving how we schedule the resources and ensuring that we make the most cost-effective scheduling decisions in all hours of the day."

The IESO's MRP business case predicted total 10-year benefits of $975 million, including $525 million in market efficiency improvements and $450 million from eliminating unnecessary congestion management settlement credit payments. After implementation costs, the IESO expects $700 million in net financial benefits for Ontario electricity consumers over the first decade.

Accounting for congestion in LMPs will reduce uplift payments. "That's where a good chunk of the cost reduction comes from," Trickey said.

Changes for Non-Quick Start Generators

A new Enhanced Real-Time Unit Commitment process will seek to optimize the scheduling of non-quick start gas generators over multiple hours versus the current system, in which dispatch is determined for individual hours.

Most non-quick start (NQS) generators need one to six hours to start up and synchronize with the grid and have limited flexibility because of minimum loading points, maximum daily starts and minimum runtimes.

The IESO will be "looking up to 27 hours ahead to schedule the least cost solution and make sure that we schedule all of the pieces together," Trickey said.

IESO also will replace its Real-Time Generator Cost Guarantee (RT-GCG) program with a Generator Offer Guarantee program. The former program provided financial and operational guarantees to NQS generators on days when they may not be able to recover their costs through energy prices. But that allowed them to claim reimbursement for start-up costs greater than what they incurred, the Ontario Energy Board (OEB) concluded in a March 6 *ruling* dismissing the generators' challenge to the MRP.

Under the new rules, NQS generators must provide a three-part offer, including energy costs, start-up costs and the cost of remaining connected to the grid while generating net-zero active power.

"The non-competitive nature of the RT-GCG leads to productive inefficiencies in the short run when demand is not met using the lowest cost resources, as offers do not accurately reflect generation costs," the OEB wrote. "The RT-GCG program also suppresses market prices below efficient levels by removing the incentives for these generators, who are frequently market price-setters, to incorporate fixed start-up costs into their offer prices. The result is a weakened price signal and a reduction of incentives for other market participants to be available at these times."

An *analysis* by the generators' consultant, Power Advisory, found a 600-MW gas generator with a heat rate of 7.5 MMBtu/MWh would have had a net margin of $75.5 million from 2018 to 2023 under the new rules, a reduction of $21 million from the current rules. The analysis also found gas generators set prices in 41% of day-ahead hours and 62% of real-time hours in summer 2021.

Impact on Loads, Resources

Nodal pricing will be applied to dispatchable loads, price-responsive loads

Candice Trickey, director of IESO's Market Renewal Program, explains the changes coming with the new nodal market at an April 16 webinar. | *IESO*

and generation, including dispatchable resources, self-scheduling and intermittent suppliers (wind and solar). Non-dispatchable loads will settle on one of 10 hourly zonal prices. Large industrial consumers can continue to pay an hourly Ontario-wide price or choose the LMP for their location.

Dispatchable loads — "a very, very small percentage" of loads, according to Trickey — must be able to respond to IESO instructions and reduce their consumption within five minutes.

Pricing for non-dispatchable loads will remain uniform across Ontario, but the new Ontario Electricity Market Price will be based on the hourly load-weighted average of all non-dispatchable load DAM LMPs plus a price adjustment to account for the cost of the differences between day-ahead and real-time schedules.

Although the calculations behind them will change, consumer bills will look the same, with an hourly province-wide price for electricity added to the Global Adjustment, which covers the cost of building and maintaining the electric system.

Intertie Transactions

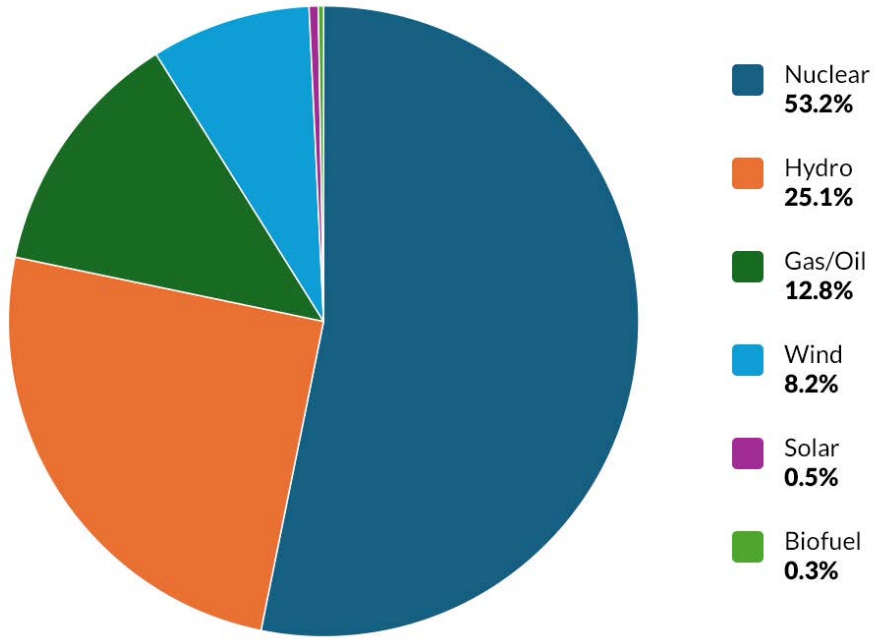
The market will use dynamic settlement pricing on its interties with Quebec, MISO, NYISO and PJM.

IESO *imported* 4.1 TWh to meet its 137.1 TWh of demand in 2023, while exporting 16.5 TWh.

The real-time intertie border price will be used if there is no congestion in the final pre-dispatch run. For export-congested

Ontario's major transmission interfaces, electrical zones and interties | *IESO* interties, the sum of the five-minute real-time intertie border prices and the pre-dispatch intertie congestion price will be used. For import-congested interties, the lesser of the pre-dispatch intertie LMP (which includes the intertie border price plus the intertie congestion price) or the five-minute real-time intertie border prices will prevail.

The current day-ahead commitment evaluates import and export legs of wheel-through transactions as linked transactions while pre-dispatch assesses both as separate transactions. In the new market, both the DAM and pre-dispatch will assess import and export legs as linked transactions.



Ontario's major transmission interfaces, electrical zones and interties | *IESO*

No Virtuals or FTR Markets

With a system-wide price and the lack of a binding day-ahead market, IESO's current system has no virtuals market for arbitraging between day-ahead and real-time prices.

And while there is a financial transmission rights market for hedging import and export risks, there is no FTR market for hedging internal congestion.

The MRP will create a virtuals market at the zonal level, like those in NYISO and ISO-NE. Market participants will be able to submit hourly bids and offers in any of nine virtual transaction zones in the day-ahead market. The Bruce zone has a low load relative to supply, so it was combined with the Southwest to create a more balanced zone, according to IESO.

MISO and PJM began their virtuals market at the zonal level until they became more established, and SPP's Markets+ virtuals market also will begin on a zonal basis when it launches, noted Emily Merchant, a director of product at *Yes Energy*.

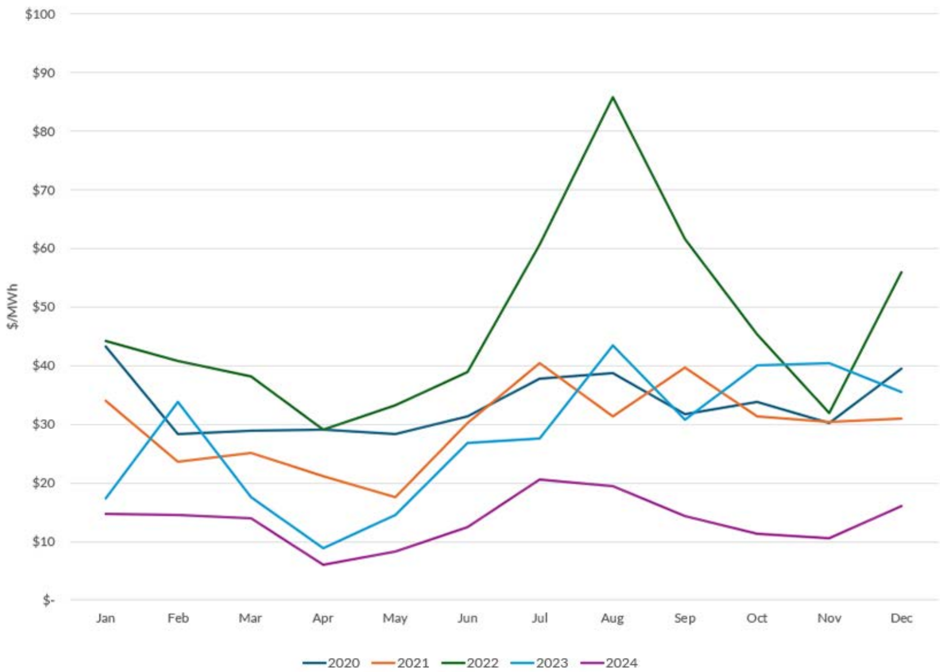
Merchant said nodal virtual markets require significant trading activity to ensure prices accurately reflect market conditions. "Given all the changes rolling out with the MRP, the market operator may have wanted to de-risk this new virtuals market by starting off zonal," Merchant wrote in a Yes Energy blog post on *preparing for the nodal market*.

The introduction of LMPs also creates the "framework to support FTRs," said Merchant, although IESO says it has no current plans for such an expansion.

"There are no internal nodal transmission rights like there are in some other markets," said Warren Hill, a senior adviser for market development at IESO. "We are not going in that direction." (See IESO's *Introduction to Virtual Traders*.)

Yes Energy power market analyst Tim Hough said the zonal virtual market may be most attractive to asset operators looking to hedge against volatility.

"Since there's only nine different nodes you can virtually transact on, there is just a lot less opportunity for traders to find a couple little nodes and a special little weather pattern to make a lot of money on," he said.



Average weighted hourly Ontario energy price | *IESO*

Market Power Mitigation

IESO will change from an ex-post to an ex-ante approach to market monitoring, employing a "conduct and impact" test to mitigate market power before prices and schedules are determined.

If a market participant fails the conduct test — or is found to have made an offer significantly above that expected under competitive conditions — IESO will apply an impact test to determine the difference in market outcome between the higher offer and the reference level offer. If the MP fails both tests, its offer will be replaced with reference levels.

Implementation Plan; Potential for Delays

The MRP will result in about 36 new public *reports* from IESO and updates to more than a dozen others, while more than 20 will be retired. The MRP also will include a new four-zone demand forecast, "so you'll be able to see demand in different areas with a more accurate view than what we would provide today," Trickey said.

IESO will provide updates on the status of the launch beginning the morning of April 30 and continuing through completion of the launch, expected May 2.

"There is always a small chance that something could happen in between now and then that would impact that — likely to be something in terms of system conditions," Trickey said. "If there was some sort of reliability event — you know, weather event, or something that impacted us — we may need to change that."

If the launch is delayed, IESO will not go forward until the first of a subsequent month, Trickey said, ruling out a launch on July 1 or Aug. 1 because of holidays. "[We] may not want to necessarily launch in the heat of the summer as well, when system conditions can be more challenging."

Market participants will need to submit dispatch data into both the legacy and renewed market systems on April 30 because existing bids and offers will not be moved to the new system. There will be no day-ahead market for the May 1 and 2 trade dates as IESO establishes the new real-time market and monitors dispatch results.

"There will be bumps along the way as we transition, because it is a very large and complex change, and one that depends on people from across the sector," said Trickey. "I know there's going to be bumps coming, but we're in a good position to weather through those."

Although IESO is making the changes to improve operational certainty and reduce system costs, initial market results may not show immediate improvements, said Yes Energy's Hough. "It'll be a very big change for a lot of people. So, I would expect some volatility there. If you're a battery asset operator — which there isn't much of in Ontario — you will probably be raking it in early on."

For More Information:

- IESO's Overview of the Transition to the Renewed Market *presentation* and *webcast*
- Yes Energy's *on-demand webinar* on IESO's nodal market launch
- Yes Energy's blog post: *20 FAQs about the Ontario Market Renewal Program*
- Yes Energy's blog post: *Ontario's Power Market Goes Nodal. How to Prepare* ■

Editor's note: RTO Insider is a wholly owned subsidiary of Yes Energy.

What to Know About IESO

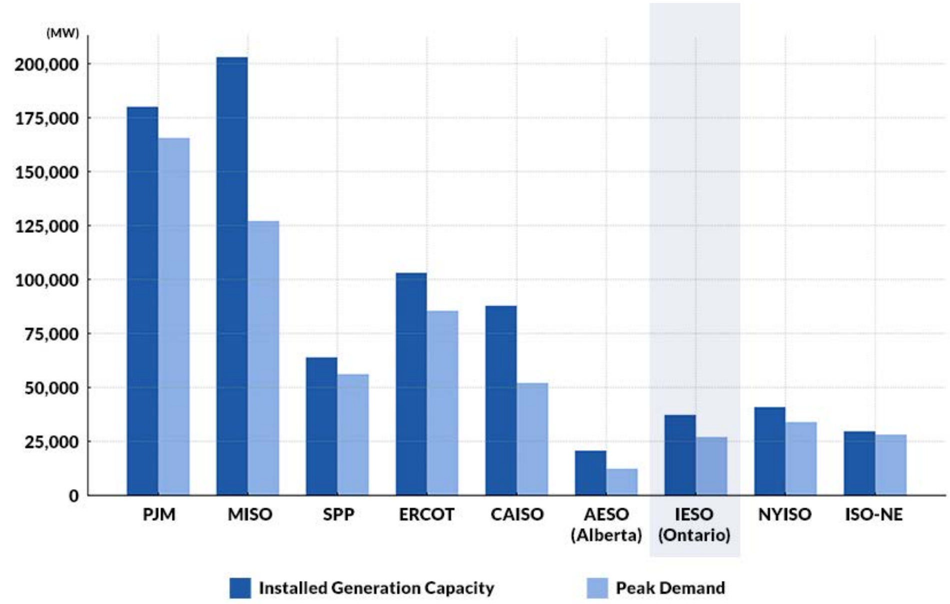
By Rich Heidorn Jr.

RTO Insider is beginning regular coverage of Ontario's Independent Electricity System Operator (IESO) in conjunction with the region's transition to a nodal market May 1. (See related story, *Ontario Introducing Nodal Market May 1*.)

Here's an introduction:

How does it compare with organized markets in the U.S.?

IESO has 37.2 GW of installed capacity and 18,640 miles of transmission, both ranked seventh among the nine organized markets in the U.S. and Canada. It hit its peak demand, 27,005 MW, in August 2006. Its record winter peak, 24,979 MW, was set in December 2004.



	PJM	MISO	SPP	ERCOT	CAISO	AESO	IESO	NYISO	ISO-NE
Circuit Miles of Transmission	88,185	77,000	72,884	52,700	26,000	26,000	18,640	11,173	9,000

IESO compared with other RTOs and ISOs | © *RTO Insider*

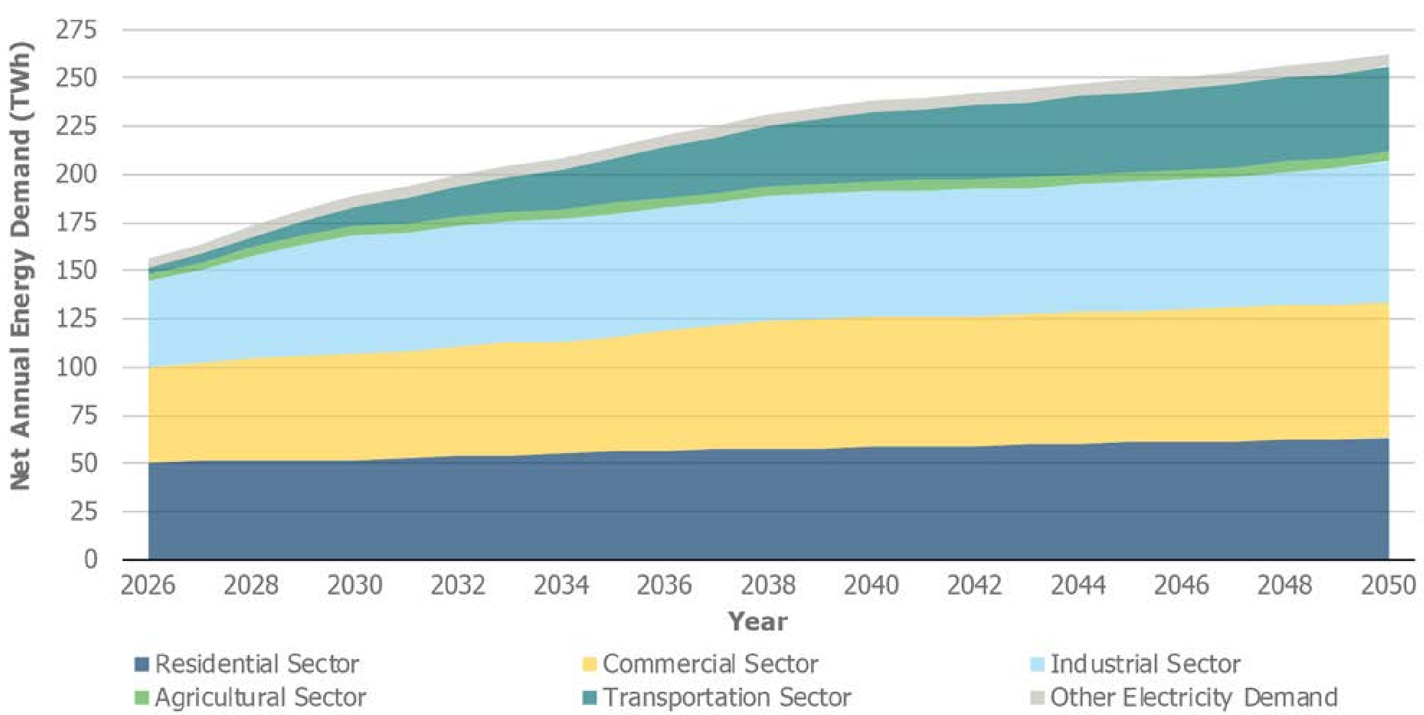
How is power demand expected to change in the future?

The 2025 *Annual Planning Outlook demand forecast* predicts a 75% increase in electric demand by 2050 — up from the 60% increase forecast a year earlier — driven by industrial and data center growth in addition to commercial sector growth, increasing population and electrification. Annual consumption is seen rising from 151 TWh in 2025 to 263 TWh in 2050.

Who owns and controls IESO?

IESO is a "Crown corporation," a government organization with a mixture of commercial and public-policy goals, owned by the government of Ontario.

It is governed by a board whose directors are appointed by the provincial government.



Annual energy demand | *IESO*

Before 1998, Ontario Hydro and municipal utilities provided power to Ontario, with electricity prices set by the provincial government.

The Ontario Electricity Act of 1998 split Ontario Hydro into IESO's predecessor and four other companies, including:

- the *Electrical Safety Authority* (ESA), which regulates and promotes electrical safety;
- the *Ontario Electricity Financial Corp.* (OEFC), which is responsible for managing Ontario Hydro's debt and contracts with non-utility generators;
- *Ontario Power Generation* (OPG), which took over Ontario Hydro's generation and now owns 66 hydropower stations, two nuclear stations and a handful of solar and gas generators in Ontario;
- and *Hydro One*, which assumed Ontario Hydro's transmission and distribution assets and now serves 1.5 million predominantly rural customers.

IESO, originally called the Independent Electricity Market Operator (IMO), was created to prepare for deregulation of the province's electrical system. It assumed the grid management functions of Ontario Hydro and was charged with developing a new electricity market.

The wholesale electricity market opened in May 2002, and the IMO was renamed IESO in January 2005.

How is IESO regulated?

The *Ontario Energy Board* regulates electric companies and sets residential electricity rates; it also approves IESO's budget and fees. The OEB reports to the *Ministry of Energy and Mines*, which sets overall policies for the electricity sector.

In an October 2024 *report*, Minister of Energy and Electrification Stephen Lecce signaled a shift from the previous Liberal government, which Lecce's Progressive Conservative Party ousted in 2018, criticizing its "failed and ideologically driven energy experiments" and "sweetheart deals that paid several times the going rate for power," a reference to 33,000 renewable energy contracts signed between 2004 and 2016 at up to 10 times the prevailing power prices.

Lecce called for "an all-of-the-above approach to energy planning, including nuclear, hydroelectricity, energy storage, natural gas, hydrogen and renewables, and other fuels, rather than ideological dogma that offers false choices and burdens hardworking people and businesses with a costly and unnecessary carbon tax."

He touted "the largest expansion of nuclear energy on the continent with the first small modular reactor in the G7. The province is upgrading and refurbishing existing reactors at Darlington, Pickering and Bruce Power to extend their lifespan and building four 300-MW SMRs at Darlington.

Planned transmission projects | *IESO*

What is its fuel mix?

Nuclear (53%) and hydropower (25%) constitute more than three-quarters of IESO's fuel mix, up from 66% in 2003. Wind (8%), solar (0.5%) and biofuel (0.4%) have increased their shares from a combined 1% in 2003. Gas and oil represent 13% (up from 11% in 2003).

Coal, which represented one-quarter of generation in 2003 — and most of the system's flexibility, according to IESO — was eliminated in 2014.

Where is it expanding transmission?

IESO is developing five new transmission lines in southwestern Ontario to serve auto manufacturers and agriculture, two new lines in northeastern Ontario to support a steel mill's planned conversion to electricity and mines, and one line in eastern Ontario to serve the Peterborough and Ottawa regions.

How does it incorporate stakeholders in new market rules?

IESO says it dedicates one to three days each month for stakeholder engagement meetings. Current *engagement issues* include *local generation*, *demand side management*, the *annual planning outlook* and *capacity auction enhancements*.

In addition, the *Strategic Advisory Committee* provides feedback to IESO's Board of Directors and executive leadership team. Current *members* represent generators, transmission and distribution companies, communities, consumers, and energy-related businesses and services. The committee held three public meetings in 2024.

The *Technical Panel* reviews proposed changes to market rules. Its current *members* include representatives of generators, renewable generators, energy-related businesses and services, importers and exporters, transmission and distribution companies, market participant consumers, residential consumers and demand response providers. It has scheduled seven meetings through the end of 2025. ■

FAQs: Ontario's Shift to a Nodal Market

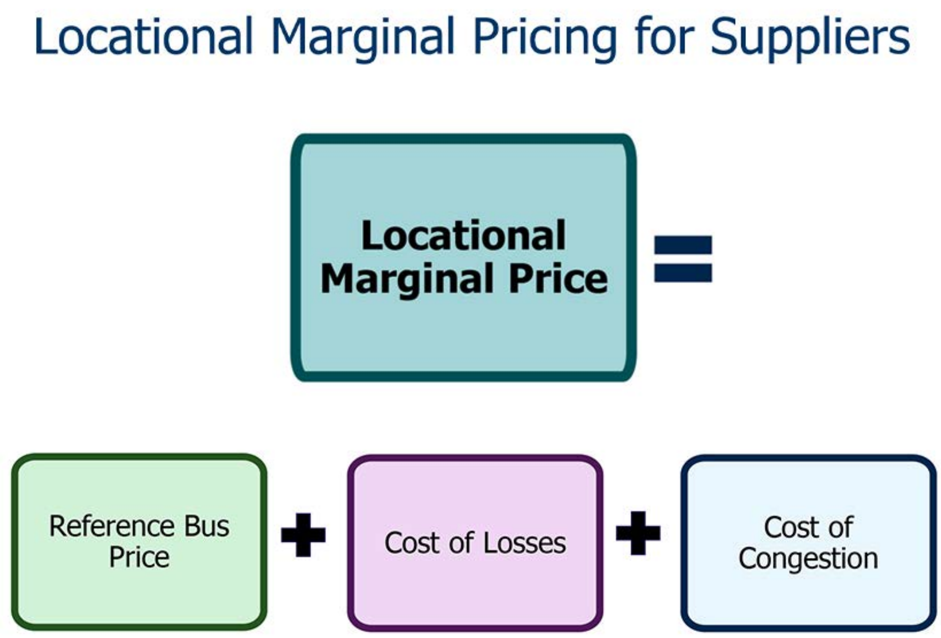
By Emily Merchant, Yes Energy

To modernize and deliver more efficient markets and ensure customers have reliable electricity at the lowest cost, IESO's Market Renewal Program (MRP) will transform Ontario's energy markets by shifting to a nodal market with a formal day-ahead market as well as a virtual market for the first time.

The market design changes summarized below will introduce more transparency into the price formation through the reporting of nodal LMPs that account for the congestion costs, instead of reporting a system-wide price and handling congestion costs through out-of-market payments. The MRP also will introduce more competition and certainty for market participants through the introduction of a formal day-ahead market as well as a new virtuals market.

Read on for some frequently asked questions on the key changes happening in IESO in May with the introduction of the Market Renewal Program. IESO is:

- Shifting to a single schedule market, establishing one schedule for both pricing and dispatch.
- Shifting from a voluntary day-ahead clearing process to a formal day-ahead market (DAM) that is financially binding.
- Moving away from out-of-market congestion payments to locational cost of congestion handled in nodal LMPs.
- Adopting nodal pricing for all generation resources and dispatchable load customers in the real-time and day-ahead markets, replacing the single price system. There will be about 970 generator and load nodes when the MRP goes live.
- Introducing price-responsive loads, a new participation type for load customers. The pricing for non-dispatchable loads will remain uniform across Ontario but will better reflect the congestion costs of delivering energy across the grid.
- Introducing a new zonal-based virtuals market that will be financially binding.
- Creating the framework to support financial transmission rights (FTRs). While this feature won't be available at the May 1 launch, the introduction of nodal LMPs and location-based congestion prices sets the stage for future FTR support.
- Providing 35 new public reports.



| *IESO*

Key Dates

This section includes key dates and go-live details for the Market Renewal Program.

When does the IESO MRP go live?

- On the morning of April 30, IESO will announce whether the MRP will launch on May 1.
- Real-time and pre-dispatch data will be published.
- Pre-dispatch data will be published at about 2:36 a.m. EST.
- On the morning of May 1, IESO will announce whether the day-ahead market will operate on May 2 for the market day May 3.
- On May 2, day-ahead market data will be published.
- On May 7, price responsive loads (PRLs) will come into effect (registered loads can begin participating as PRLs).
- On May 8, virtual trading begins.

Market Participation Information

This section includes information on market participation requirements.

Do you have information on minimum market participation requirements, e.g. cash/collateral requirements?

For this information, see the Guide on Prudentials. A prudential support obligation will be determined separately for physical transactions and virtual transactions, informed by all activity in the day-ahead and real-time time frames. A market participant authorized for both types of transactions will have two separate prudential support obligations.

Data Publication Information

This section includes information on data publication nuances (e.g., time zones) and data accessibility in the IESO sandbox/test environment.

How can I access data in the IESO sandbox environment to familiarize myself with the data before market go-live?

Public site: *https://reports-public-sandbox.ieso.ca/public/*

Gateway sandbox: https://gateway-sbx.ieso.ca/

How to access the data: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/Market-Participant-Testing/Connectivity-Testing-IESO-Gateway.pdf

Will IESO keep publishing data in EST and not EDT when the clock moves forward?

IESO will keep publishing data in EST, but the DAM process timelines will follow Eastern Prevailing Time (EPT).

Pricing Data

This section includes information related to the reporting format of LMPs, reference nodes and maximum/minimum price limits in the real-time market.

Will IESO publish nodal day-ahead prices ahead of the nodes going live?

Nodal day-ahead prices are available in the *IESO sandbox environment* before go-live. Yes Energy already has this data flowing into its products. Note: This is just test data that is meant for market participants to familiarize themselves before the MRP go-live.

Timing of newly created or updated data IESO reports:

- May 1 is the first day of real-time market operation and the first day of real-time report publication.
- On May 2, market participants will submit day-ahead market dispatch data. The first day of day-ahead report publication for the trade date is May 3.

Will the pricing data be reported by locational marginal price components (LMP, congestion, loss) for both nodal and zonal prices?

The day-ahead and real-time LMP price reports will include the LMP, loss and congestion components for the more than 900 generator and load nodes. The zonal price reports also include the LMP, loss and congestion components. *See more information*.

How is the Hourly Ontario Energy Price (HOEP) going to be calculated after MRP?

After the MRP implementation, HOEP will be replaced by LMPs, and contracts will be settled based on those LMP prices. HOEP's global adjustment (GA) charge will continue to exist following the implementation for Ontario.

What's now the reference node in IESO?

By default, the reference bus will be the Richview Transformer Station. If the reference bus is out of service, then an alternate station will be chosen as per the prevailing system conditions (*Real-Time Calculation Engine, p. 42*).

Is there a maximum or a minimum price in real time in Ontario post-MRP?

The settlement floor price is -$100/MWh. The maximum settlement will remain at $2,000/MWh. Resources still can offer as low as -$2,000/MWh, however.

Transmission Congestion Data

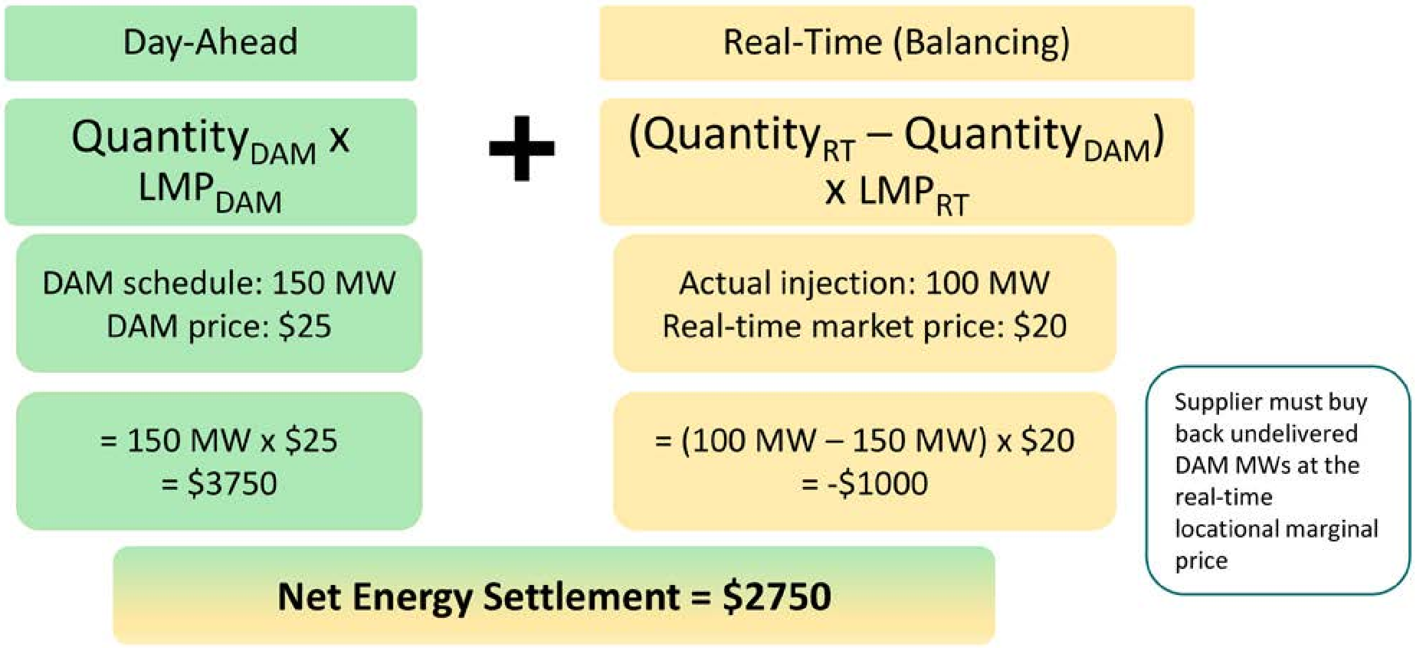
This section provides information regarding the availability of transmission constraint data, whether FTRs will be tradable in IESO post-MRP and transmission rights (TR) products.

Will IESO post binding constraint data?

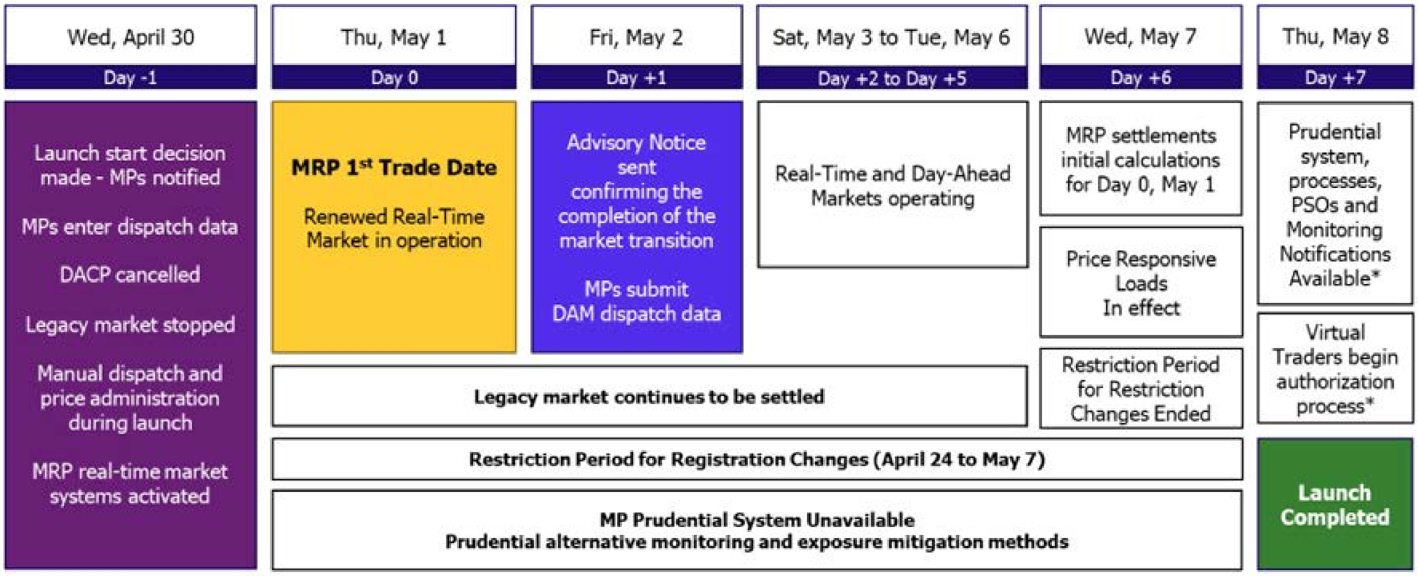
Yes, after MRP, IESO will publish real-time, day-ahead and predispatch binding constraint files. Unfortunately, the data will be published on a six-day lag on its public site. Read more about the *day-ahead binding constraint shadow price report*, the *real-time binding constraint shadow price file* and the *predispatch binding constraint file*. IESO will publish day-ahead and predispatch security constraint files on a more real-time cadence, but this provides visibility into the constraints assumed in the day-ahead clearing engine and predispatch engine. Read more about the *day-ahead security constraint report* and *predispatch security constraint report*.

Will shift factors be posted?

Not directly. IESO used to publish an annual loss penalty factor report. Per IESO,



Two-settlement example | *IESO*



Launch plan overview | *IESO*

"Loss penalty factors are used to account for the incremental change in transmission losses as a result of the change in output from a resource — including generators, loads and intertie connections." While they sound similar to a shift factor, the range of *2024 loss penalty factors* is 0.91-1.22. IESO says the dynamic loss penalty factors, which will be calculated in each pricing pass of the calculation engine, can be determined using the LMP reports (*IESO Publishing and Reporting Market Information (Final)*, p. 37).

Will there be an FTR product?

No, there will not be a financial transmission rights (FTR) product. IESO offers and will continue to offer a transmission rights product that market participants can use to hedge risk (e.g., for unpredictable congestion costs). Transmission rights are traded at the zonal level, not the nodal level.

Will financial transmission rights still settle on the real-time price, or will they settle on the day-ahead price?

Under MRP, financial transmission rights will be settled based on the day-ahead congestion prices instead of the real-time price.

Virtuals Market

This section provides more information on the new virtuals market in IESO, including the number of tradable nodes, price formation and data availability.

How many zones will be tradable in the virtual market?

Ontario has 10 electrical zones, but only nine virtual trading zones. The Bruce and Southwest are combined into one Southwest virtual trading zone. See *IESO's Introduction to Virtual Traders Report* for more information.

How is the virtual zonal price calculated?

Virtual transactions will be settled with the virtual zone prices, which is calculated as the load-weighted average of the LMPs at all load points within the zone. Load distribution factors (LDFs) will be used to determine the weight of each LMP in the virtual trading zone. Like with other prices, day-ahead market and real-time virtual zonal prices will be calculated and used for settlement. Pre-dispatch zonal prices will be provided for information purposes only.

How far back will the virtual price data be available?

IESO is launching a virtual market for the first time on May 8. Test data for the new virtuals market is available in the *IESO sandbox site*.

Will there be uplifts on virtuals similar to other ISOs in the U.S.? Will there be monthly or weekly settlements for virtuals?

There will be uplifts on virtuals. Due to the DAM reliability scheduling uplift, virtual transactions can be allocated a portion of the cost of DAM-MWP and DAM-GOG generated in Pass 2: reliability scheduling and commitment of the DAM calculation engine for every MW cleared in the DAM.

Virtuals will be settled hourly and invoiced monthly. IESO will continue using monthly billing periods for settlement of the physical market (this includes both physical and virtual transactions), so virtual transactions will appear on the monthly invoice. Invoices will be issued 10 business days after the end of the billing period. The market participant payment date is the second business day following the issuance of the invoice. The weekly invoice will continue to contain only settlement amounts for the transmission rights auction.

Emily Merchant is a director of product at Yes Energy in charge of setting the vision and strategy for Yes Energy's PowerSignals, QuickSignals *and Trading Regions (public data) products. Emily has over 14 years of experience working in the energy industry. Prior to Yes Energy, Emily worked at Navigant Consulting (now Guidehouse), E Source, Energy Trust of Oregon and GDS Associates.*

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Maine PUC Seeking Feedback on Transmission, Generation Procurement

By Jon Lamson


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The Maine Public Utilities Commission is seeking feedback and indications of interest for a procurement of generation and transmission capacity to connect at least 1,200 MW of clean energy in Northern Maine to ISO-NE.

State law *requires* the PUC to seek long-term contracts for generation in Aroostook County and for a new transmission line to connect it to ISO-NE. The sparsely populated county has significant clean energy potential owing to its high wind speeds, but Northern Maine is not directly connected to the ISO-NE system, instead connecting to the Eastern Interconnection through New Brunswick, Canada.

Policymakers and developers in the region have long seen the region as a potential source of cheap power. ISO-NE and the New England States Committee on Electricity (NESCOE) have focused the first Longer-Term Transmission Planning (LTTP) procurement on facilitating the interconnection of 1,200 MW of onshore wind and alleviating transmission constraints in the southern part of the state. (See *ISO-NE Releases Longer-term Transmission Planning RFP*.)

The PUC has said it aims for its procurement to be complementary to the LTTP procurement, which is being run by ISO-NE. In the request for information issued in early April, the PUC asked for feedback on how to best coordinate and sequence its solicitation with the LTTP process (*DPU 2024-00099*).

Why This Matters

Onshore wind development in Northern Maine is a key component of New England's clean energy strategy, but there is significant uncertainty and a long road ahead before power in this remote area can be developed and connected to ISO-NE.

The RFI highlights some unique challenges and questions associated with coordinating the two procurements. ISO-NE's request for proposals features a Sept. 30 submission deadline, and the RTO does not expect to select a project until fall 2026. There is also no guarantee that a project will emerge from this RFP, as NESCOE has the right to terminate the process even if a proposal is selected by the RTO.

If Maine waits until the conclusion of the LTTP process to proceed with its own procurement, this will likely push its process back for more than a year.

The state also must grapple with the challenges of simultaneously procuring generation and transmission. The PUC asked for input on the interdependencies between these two aspects of its procurement, as well as on potential "advantages or disadvantages to allowing or prohibiting combined or linked transmission and generation project proposals."

The PUC is seeking feedback on potential contact adjustments and flexibility for generation projects to account for risks of transmission delays. The PUC also asked for input on long-term contract length, inflation adjustment mechanisms, mitigating permitting risks, the availability of federal funding and tax credits, and the potential impact of federal policy, tariffs and federal permitting requirements.

The RFI also includes questions about partnering with other states for the procurement, as the statute specifically directs the state to seek partnerships with other states and utilities. Massachusetts previously agreed to purchase up to 40% of the generation and transmission capacity from an earlier iteration of this procurement, but it was canceled in 2023 by transmission developer LS Power. The company cited cost increases driven by project delays, inflation, supply chain issues and increased interest rates (*DPU 2021-00369*).

In October 2024, the Department of Energy under President Joe Biden agreed to serve as the anchor off-taker for an Avangrid proposal to build transmission into Northern Maine, awarding the project up to $425 million to help de-risk the project. (See *Long Road Still Ahead for Aroostook Transmission Project*.)

At the time, Avangrid said it expected the PUC to announce winning bids at some point in 2025. This timeline now seems highly unlikely, and federal policy changes may pose a significant threat to the funding.

The PUC is requesting feedback from stakeholders by June 2, with supplemental comments due at the end of September. It also asked developers to submit indication of interest forms by June 2, which should include "a brief description of the project or projects they would develop" and "a description of how the project(s) would be impacted by different possible outcomes of the ISO-NE regional solicitation." ■

MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction

By Amanda Durish Cook

MISO's 2025/26 capacity auction returned $666.50/MW-day prices across all zones in the summer, reinforcing the need for members to build new generation fast, the grid operator said.

While none of MISO's resource zones experienced a capacity deficit, MISO said it's inching closer to pervasive shortfalls. The summer's capacity *prices* represent a 22-fold increase over summer capacity prices in 2024.

Beyond summer, MISO zones cleared uniformly at $69.88/MW-day in spring and $33.20/MW-day in winter. For fall, MISO Midwest cleared at $91.60 while MISO South cleared at $74.09/MW-day. MISO said the split in fall pricing occurred due to its transfer limits between its Midwest and South regions.

Annualized, MISO's capacity prices are $217/MW-day for MISO Midwest and $212/MW-day for MISO South.

Prices go into effect June 1, when the planning year begins.

In the 2024/25 capacity auction, Missouri's Zone 5 cleared at the $719.81/MW-day cost of new entry for generation in spring and fall. All other MISO zones cleared at $30/MW-day in the summer, $15/MW-day in the fall, $0.75/MW-day in the winter and $34.10/MW-day in the spring. (See *Missouri Zone Comes up Short in MISO's 2nd Seasonal Capacity Auction, Prices Surpass $700/MW-day*.)

The 2025/26 auction was MISO's first to feature sloped demand curves by season. The grid operator hoped the curves would function as a safety net to have more capacity on hand than strictly necessary to meet planning reserve margin requirements. FERC in 2024 allowed MISO to use them in place of the vertical demand curve it had been using since 2011. (See *FERC Approves Sloped Demand Curve in MISO Capacity Market*.)

MISO said the sloped curves placed an expected higher price on capacity, "reflecting the increased value of accredited capacity beyond the seasonal planning reserve margin target." The grid operator said the auction cleared 1.9% above its 7.9% summer planning reserve margin, the highest margin it has. MISO said, effectively, it's heading into summer with a 10.1% summer margin at 101.8 GW in MISO Midwest and an 8.7% margin at 35.7 GW in MISO South.

Ahead of the auction, MISO anticipated a 122.66-GW summer coincident peak and required a 7.9% planning reserve margin at 135.3 GW for the auction.

MISO said as with previous auctions, most of its load-serving entities "self-supplied or secured capacity in advance" and thus are shielded from this year's pricing.

Why This Matters

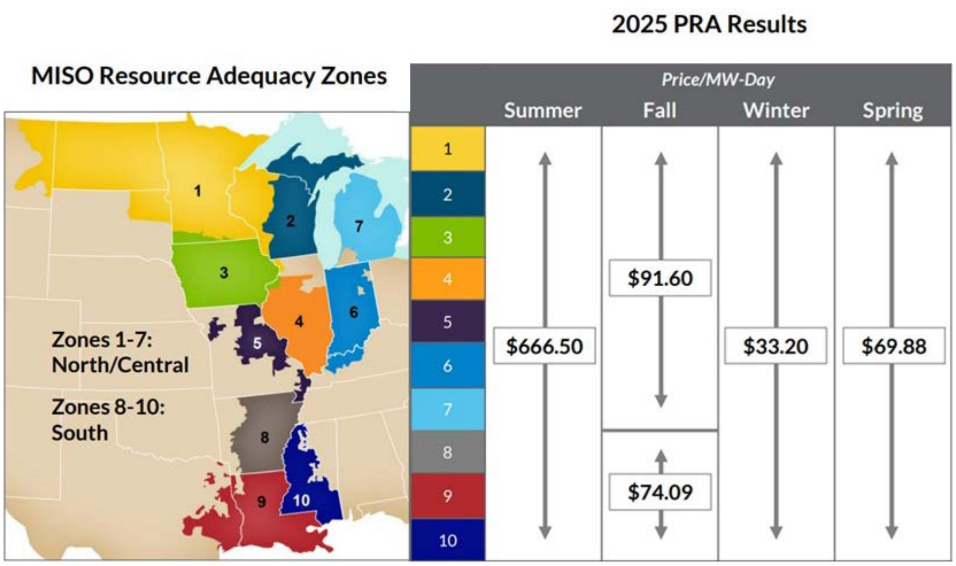
A few LSEs in MISO may have sticker shock over summer 2025 capacity auction prices jumping to $666.50/MW-day from $30/MW-day a year ago. MISO said auction pricing bolsters its case that members need to add generation now.

The RTO said while its sloped curves cleared extra capacity, it noticed the footprint's spare capacity beyond planning reserve margins dwindled 43% this year compared to summer 2024. MISO said the drop occurred despite a slightly lower planning reserve margin aim than summer 2024's 9% target. The RTO said it oversaw 140.7 GW in summer 2024 offers and 137.8 GW in summer 2025 offers.

The 5.1 GW in new capacity, made up mostly of solar generation, and 1.2 GW in capacity accreditation increases added over the last planning year were no match for 4.9 GW in accreditation decreases, 3.3 GW in retirements and suspensions, and a nearly 1-GW loss in external suppliers, MISO reported.

"New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports. The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions," MISO said in a presentation accompanying auction results.

Over 2024, MISO and the Organization of MISO States through their joint resource adequacy survey showed that anywhere from a 1.1-GW surplus to a 2.7-GW shortfall could be possible by summer 2025. MISO leadership has been cautioning its stakeholders for more than a year that faster generation additions are a must. ■



MISO 2025-26 Planning Resource Auction clearing prices by season and zone | *MISO*

MISO Debuting Flag System to Curb Deviations from Dispatch

By Amanda Durish Cook

Xcel Energy

MISO said it will debut a new flag system within weeks to give stronger signals to generation owners when their units deviate from their dispatch instructions.

The flag, planned for *rollout* June 3 in MISO's unit dispatch system, would let operators know when their resources appear to be disregarding MISO's dispatch instructions. Along with the flag, MISO plans to provide a reason code, detailing the reliability reason MISO's five-minute setpoint instructions should be followed.

In an April 22 question-and-answer session for stakeholders, MISO's John Harmon said the new codes behind uninstructed deviations should bring "clarity and context" to resource operators.

RTO staff said units not sticking to MISO instructions create balancing and frequency issues that sometimes require out-of-market actions in the control room. Staff have said that modeled flows in MISO's dispatch system are diverging more and more from actual flows, resulting in system operating limit violations, balancing issues and frequency deviations. (See *MISO: Flag, Penalties Needed to Address Generators' Uninstructed Deviation*.)

Harmon said the flag would apply to all generation resources except energy storage. Historically, MISO and its Independent Market Monitor have said wind generation sources are among the worst offenders when they're ordered to dispatch down.

The new system requires MISO to make software changes to its unit dispatch system. In addition to the flag, the RTO eventually plans to levy penalties in market settlements for units that ignore dispatch instructions. ■

Consumer Groups Invoke DOJ Stance in Stalled Complaint on ROFRs in MISO Planning

By Amanda Durish Cook

A collective of consumer groups has invoked a recent letter from the U.S. Department of Justice to get FERC to act on its three-year-old complaint against MISO for deferring to state right of first refusal laws in regional planning.

The complaint — from the Industrial Energy Consumers of America, the Coalition of MISO Transmission Customers and others — asks FERC to force MISO to brush off state ROFRs when planning transmission (EL22-78). FERC has yet to address it. (See *Consumer Collective Again Asks FERC to Strike ROFR Laws from MISO Planning*.)

In mid-April, Paul Cicio of Industrial Energy Consumers of America entered a *letter* into the record from the DOJ to Iowa State Sen. Jesse Green (R), urging the Iowa Legislature to rethink a reintroduction of the state's ROFR law that was overturned in 2023. (See *Iowa ROFR Law Overturned, Throwing Multiple MISO LRTP Projects into Uncertainty*.)

Iowa legislators in early 2025 reintroduced an Iowa ROFR bill in the Senate (*SB 1113*).

The collection of consumer groups challenging MISO's regard for ROFRs in planning has said Iowa provides a case study in the delay and litigation that ROFR laws introduced. It argues MISO should be able to disregard them.

The March letter from Assistant Attorney General Abigail Slater calls competition a "core organizing principle of the American economy" and said ROFRs' bypass of competitive bidding disadvantages firms "that could offer lower prices, greater innovation and superior terms to Iowa's utility customers."

Why This Matters

The Industrial Energy Consumers of America, the Coalition of MISO Transmission Customers and other consumer groups are trying to get FERC's attention on a dormant complaint against MISO accounting for state ROFRs in planning by sending a recent pro-competition letter from the Department of Justice.


ITC Midwest

Slater reminded the Iowa Legislature that President Donald Trump declared a National Energy Emergency in early 2025 and that the DOJ has filed briefs in other cases that challenge the constitutionality of state ROFR laws.

"The bill turns a 'preference for further investment in Iowa transmission infrastructure by electric transmission owners' into a legal grant that shields incumbents from competition," the letter said. "In some cases, incumbent operators will be best positioned to deliver high-quality, cost-effective infrastructure projects quickly. But even in such circumstances the threat of competitive pressure from potential rivals will incentivize better outcomes like lower prices for consumers and more robust and innovative project designs. In other cases, non-incumbent firms may offer lower costs, and better project designs, and they should be allowed to compete on the basis of the better value they offer."

MISO: Complaint Still Has No Legs

MISO, as it has for years, continues to oppose the complaint. In an early April response, it said the consumer alliance's attempt to cut the state ROFR exemption from its tariff is a collateral attack on MISO's accepted compliance under FERC's Order 1000.

MISO in 2022 assigned several projects from its first, $10.4 billion long-range transmission plan (LRTP) portfolio to incumbent transmission owners in Iowa based on the valid state ROFR in place in Iowa at the time. The RTO pointed out that it wasn't until early December 2023 that the Iowa District Court overturned the ROFR on a remand from the Iowa Supreme Court.

"MISO has been clear that, following the Iowa District Court's decision on the merits, the Iowa ROFR law was no longer applicable, on a prospective basis," the RTO said. It ended up using its variance analysis to examine project assignments in Iowa for the subsequent, $21.9 billion LRTP portfolio. MISO ultimately left that round of projects also to its incumbents, concluding the district court's order did not change project assignments nor direct that projects be reclassified into competitive facilities. MISO also said the district court specifically said it was not a party to the court's action.

"Far from indicating that the state ROFR exemption is unjust and unreasonable or otherwise unworkable, the tariff process worked in the Iowa case despite its complicated litigation posture and the attendant uncertainty," MISO argued. "Further, to the extent the consumer alliance suggests that MISO must apply ROFR determinations retroactively for the state ROFR exemption to be just and reasonable, such a position lacks merit. The filed rate doctrine and the rule against retroactive ratemaking are clear that MISO cannot revisit such determinations without a binding legal directive from the commission, subject to the applicable FPA process."

MISO acknowledged Indiana's ROFR also is the target of fluid and complex litigation. (See *7th Circuit Lifts Injunction on Indiana ROFR, Remands LS Power's Case*.) The RTO said, so far, the ROFR has been in effect throughout the development of the second LRTP portfolio, and as such, it again assigned the lines to the incumbent transmission owners. It said it again would draw on a variance analysis to confirm project assignments in Indiana, if needed.

"MISO does not know what conclusion the federal courts ultimately will reach with respect to the constitutionality of the Indiana ROFR law. As the 7th Circuit recognized, there are many different unknowns at this time. ... If the Indiana ROFR law is determined to be unconstitutional, MISO will give a prospective effect to any such determination, consistent with the filed rate doctrine and any directives from the commission," MISO said.

The grid operator pushed back against the consumer alliance's claims that MISO "default[s] to incumbent project assignment regardless of questions regarding the constitutionality of state laws." It said it was simply applying its tariff as written. ■

MISO: New Software Effective, Faster than Previous Queue Study Process

By Amanda Durish Cook

MISO has concluded that Pearl Street's SUGAR automation software is an effective alternative to the power flow simulations it used to conduct to identify network upgrades for generation projects in the queue.

MISO released an *analysis* comparing the software's ability to pinpoint upgrade needs for new generation entering the system with MISO's previous analyses on the 2021 cycle of generation proposals. The RTO said SUGAR performed at a 99.23% match rate with "minimal deviations" when searching for thermal constraints, a 100% match rate with some extra identified constraints when looking for flowgate limits and a 99.03% match rate when spotting voltage issues with "justified" minor violations.

Ahead of the analysis, MISO said SUGAR would have to identify at least 98% of constraints uncovered through its legacy analyses to be considered a success. MISO said across all three comparisons — thermal, flowgate and voltage — SUGAR results aligned with MISO studies 99.2% of the time.

MISO is using Pearl Street's *SUGAR* (Suite of Unified Grid Analyses with Renewables) software to screen generation projects and perform the first phase of studies in the queue. It's betting the tech startup's assistance with conducting studies can dramatically accelerate its yearslong queue processing. Austin, Texas-based software company Enverus *acquired* Pearl Street in March.

The RTO plans to start the first phase of studies on the 2023 batch of project proposals in July. It won't begin analyzing 2025 entrants until the end of the year. MISO hopes to have all projects in those cycles striking interconnection agreements over 2026, with the still-in-progress 2022 cycle proceeding in the second quarter, 2023 in the third quarter and 2025 by the end of 2026. (See *MISO Unveils Later Timeline for Queue Processing Restart*.)

MISO skipped acceptance of a 2024 queue class altogether. Throughout 2024, it delayed kickoff of studies on the 123 GW of projects that entered the queue in 2023 while Pearl Street assisted with modeling.

The RTO hasn't processed a new queue cycle in more than a year, saying it needs to introduce study automation and implement a megawatt cap to make processing requests less daunting. (See *MISO to Skip 2024 Queue Cycle While it Automates Study Process with Tech Startup*.)

MISO found that SUGAR completed the first phase of interconnection studies faster while estimating similar costs for network upgrades. MISO said while it spent 686 days to ultimately estimate $13.36 billion in upgrades for the 2021 queue cycle of projects, SUGAR estimated $13.25 billion for the same batch of projects within 10 days.

MISO staff at an April 22 Interconnection Process Working Group said SUGAR provided a good match for the RTO's longer-form interconnection studies.

"These results confirm that SUGAR can be utilized in MISO's [first definitive planning phase (DPP)] studies with minimal impact to stakeholders while also providing significantly increased speed in conducting MISO DPP Phase 1 studies," MISO wrote in its analysis.

MISO said SUGAR results are in "excellent agreement" with MISO's previous study process regarding flowgate project assignments. When hunting voltage constraints, MISO said SUGAR landed on 102 of the 103 constraints it previously identified while reporting six more that didn't turn up in MISO studies. MISO said the additional constraints SUGAR called out are "deemed acceptable within the bounds of engineering judgment."

MISO also said SUGAR noted 259 of the 261 thermal constraints MISO previously reported. The RTO said it expected small deviations in the output of different powerflow tools.

Meanwhile, one MISO region already has surpassed MISO's newly enacted 50% of peak load annual interconnection queue cap. (See *FERC Approves Annual Megawatt Cap for MISO Interconnection Queue*.)

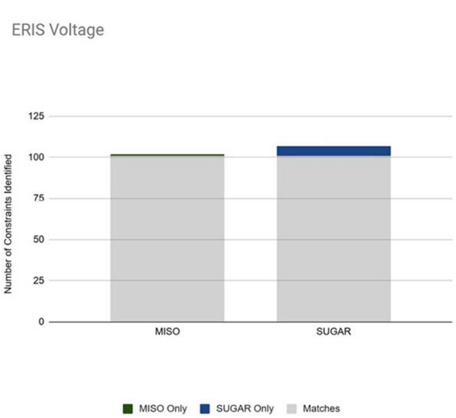
The East ITC study region, which contains Michigan's Zone 7, *exceeded* the cap at 29 submittals at 10.52 GW. Any other projects that hoped to enter under the 2025 cycle now must queue up for the 2026 cycle.

MISO has been allowing projects to line up for 2025 queue processing since last year. Its cap for the 2025 queue cycle is nearly 78 GW. So far, MISO has recorded 154 project submissions at 41.64 GW.

At the April 22 meeting, John Liskey, of the Citizens Utility Board of Michigan, said the resources that entered before the East region's cap was exceeded contain a large amount of gas capacity, which could violate Michigan's renewable energy standard of 50% by 2030 and 60% by 2035. ■

The Bottom Line

MISO used the studies it conducted under its 2021 cycle of generator interconnections to test the automated software it's transitioning to for prescribing network upgrades. The RTO found results matched 99.2% of the time.



A comparison of voltage constraints identified by SUGAR and previous MISO analysis | *MISO*

MISO, PJM Forgo Typical Interregional Studies for Novel Transfer Work

By Amanda Durish Cook

The Bottom Line

MISO and PJM told stakeholders not to expect either of their traditional interregional planning studies in 2025 due to ongoing work on a transfer capability study that could produce upgrades in 2026.

MISO and PJM will not take on customary interregional planning studies this year, deciding they have enough on their plates with a new and in-progress joint transfer study.

The grid operators announced they would devote their attention throughout 2025 to their interregional transfer capability study (ITCS), a new type of study that might yield projects that allow for a greater volume of transfers. (See *Smaller Projects Expected from Maiden MISO-PJM Joint Tx Study* and *OMS, OPSI Pen 2nd Letter to MISO and PJM to Compel Meaningful Interregional Planning*.) The two decided against undertaking a more traditional coordinated system plan, which could result in more expensive interregional market efficiency projects, or their established, smaller targeted market efficiency project study.

MISO and PJM arrived at the conclusion after conducting an annual issues review designed to look for transmission opportunities. The process is required under their joint operating agreement.

The RTOs said there's a possibility their ITCS changes the way the two manage future interregional studies. They said their transfer study could lay the "foundation for assessing future coordinated planning needs." MISO and PJM are working from a blended, long-term model that combines the RTOs' assumptions to identify system needs in the transfer study, a first for two major North American RTOs.

"By focusing our efforts on the ITCS, we aim to gain a clearer understanding of emerging transfer limitations and deliverability issues across the seam. The insights gained through this study will help guide future planning activities and determine whether additional interregional analysis or project development is appropriate in subsequent years," MISO and PJM said in an April 18 emailed statement to their stakeholders.

The two said they would update stakeholders as the transfer study progresses and if "planning needs arise that warrant further coordination."

MISO and PJM so far have *identified* more than 30 shared reliability, transfer and economic issues that could form the basis for upgrades under the ITCS.

In an emailed statement to *RTO Insider*, MISO said the goal remains to develop a draft portfolio by the end of 2025. MISO said it and PJM plan to open a monthlong stakeholder comment period at the end of April to solicit solutions.

MISO and PJM previously *said* they would focus on equipment upgrades and projects that can use existing rights-of-way in the first transfer study. They said the study, combined with FERC Order 1920, could open the door for longer-term interregional planning and greenfield projects.

MISO and PJM historically have approved one *interregional market efficiency project* in 2020 and four sets of the *smaller* targeted market efficiency projects aimed at relieving congestion since 2017. They haven't completed an interregional transmission planning study since 2022. ■

The top transfer limits MISO and PJM singled out as part of their transfer study | *MISO and PJM*

Oxbow Incident: FERC Denies Solar Farm's Waiver

By Tom Kleckner

FERC has denied Oxbow Solar's waiver request for a 24-month extension of its commercial operation deadline for a planned generating facility in Southwestern Electric Power Co.'s northwestern Louisiana service territory.

In its April 23 order (*ER25-1274*), the commission said Oxbow Solar had failed to meet FERC's criteria for waivers of tariff provisions: that the applicant acted in good faith; the waiver is of limited scope; it addresses a concrete problem; and the waiver does not harm third parties or have any other "undesirable consequences."

FERC found Oxbow Solar failed to show it acted in good faith to diligently advance the solar facility and said it appears "Oxbow Solar's need for the instant waiver may have been caused, in part, by its own inaction." The developers did not dispute they failed to meet an amended generator interconnection agreement's milestone to notify SWEPCO to begin construction or that they met the milestone almost two and a half years late, the commission said.

The planned 73.5-MW generating facility had an initial operating date of Dec. 1, 2023.

FERC also said Oxbow Solar failed to demonstrate that granting the requested waiver would have addressed a concrete problem. It said Oxbow Solar's only justification is that "the market has corrected for increased project costs."

"Given the absence of a detailed explanation in the record of how the 24-month extension will allow Oxbow Solar to secure financing and achieve commercial operation, we find that Oxbow Solar has failed to sufficiently demonstrate that its waiver request will remedy a concrete problem," the commission wrote.

Oxbow Solar had requested the extension, from Nov. 30, 2026, to Nov. 30, 2028, back in February. It said rapid increases in insurance, engineering, procurement, and construction costs and difficulties in securing solar components had hampered its ability to negotiate offtake agreements in time to meet the commercial operation deadline. ■

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Clean Path Transmission Plan Draws Support, Criticism

NYPA Seeking Priority Review for $5.2B HVDC Proposal

By John Cropley

Stakeholders and advocates are sounding off for and against expedited review of the $5 billion-plus Clean Path transmission proposal that would feed power into New York City.

Efforts to build the 175-mile underground HVDC line suffered a setback in late 2024 due to cancellation of a larger project in which it was packaged with 23 new wind and solar facilities in rural New York. (See *$11B Transmission + Generation Plan Canceled in NY*.)

The New York Power Authority (NYPA) is pressing ahead on its own with the transmission component. (See *NYPA Files Petition with New York PSC to Save Clean Path Project*.)

NYPA is asking the state Public Service Commission (PSC) to designate Clean Path a priority transmission project (PTP) (Case *20-E-0197*) in hopes of accelerating its development and speeding up the benefits it would provide to the environment and to grid reliability. (See *NYPA Argues Clean Path Potential Benefits Outweigh Cost*.)

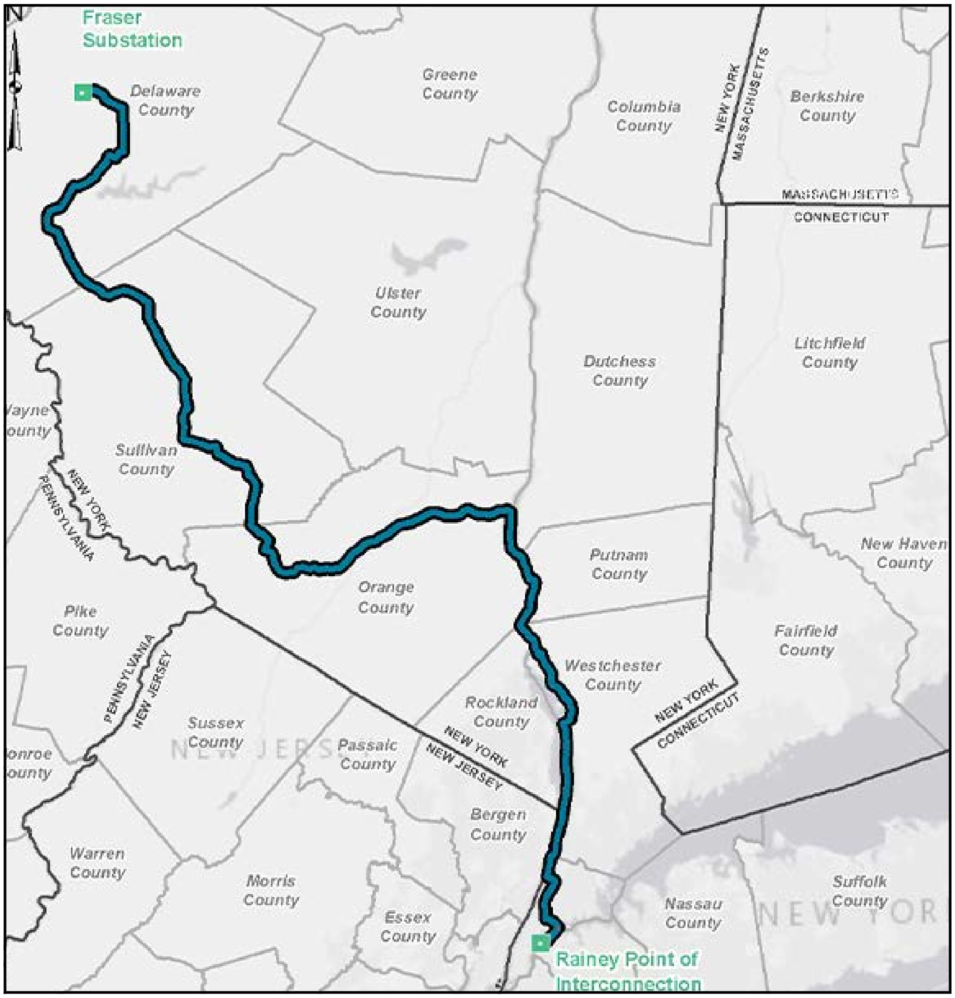
NYPA estimates the cost of Clean Path at $5.2 billion. It proposes allocating 60% of the cost to NYISO Zone J (New York City), which could reduce its reliance on fossil fuel generation and enjoy cleaner air thanks to Clean Path, and 40% to rest of the state on a load-share basis.

The PSC solicited comments on NYPA's request in February, and the window closed April 21; a spokesperson said April 22 the comments will be reviewed but there is no timetable yet for further action.

In the comments, advocates for environmental quality and for organized labor generally argued in favor of priority status for the proposal while many in the energy sector raised objections.

Why This Matters

Priority review status might boost lagging efforts to decarbonize New York's grid and might boost what some see as a flawed plan.



The proposed route of the Clean Path New York underground HVDC transmission line is shown. | *Clean Path New York*

These objections often focused on the need or lack of need for Clean Path, and the fact that the proposal differs substantially from the one first submitted.

The original project, called CPNY or Clean Path New York, was a public-private generation-transmission proposal by NYPA and Forward Energy that won a state contract for Tier 4 renewable energy certificates. The contract was terminated in November, the partnership was dissolved, and Clean Path now is transmission-only.

Among the comments:

National Grid Ventures said without the 3.8-GW suite of renewable generation projects originally envisioned for CPNY, Clean Path should not be granted priority status. It further said the project itself should not proceed without independent verification of its need. It concluded: "If the commission determines the project is required and that it should be granted PTP status, then NYPA should be ordered to competitively solicit proposals and reserve the right for the commission to approve who NYPA ultimately teams with for the project."

PSEG Long Island supports designation as a priority transmission project on the belief that, because NYPA's cost of debt is lower and it is tax-exempt, development costs and costs to customers would be lower than if a private developer did the work.

Independent Power Producers of New York noted that CPNY won its state contract through a competitive solicitation and argued the PSC should consider new competitive solicitations to avoid burdening ratepayers with unnecessary costs. It added that renewable energy development is behind schedule in New York. “Thus, any ‘urgency’ to complete the Clean Path project is an overreach at best and should not outweigh the commission’s long-established precedent that competitive solicitations ensure the lowest cost for consumers.”

Alliance for Clean Energy New York supports priority designation as a way of addressing future reliability and transmission security deficiencies; reducing the need for more expensive local generation to meet the locational minimum installed capacity requirement in Zone J; and facilitating development of renewable resources upstate, where the HVDC line would originate.

New York Transco — which is collaborating with NYPA on another major downstate transmission project, Propel NY Energy — said NYPA has not demonstrated that Clean Path meets the criteria for priority designation. It also questioned whether Clean Path could unbottle existing renewable capacity in the region and said NYPA has failed to support the cost recovery mechanism it proposed.

Consolidated Edison Co. and four other utilities said the PSC should deny NYPA’s request because NYPA had not shown a need for urgency and its petition lacks sufficient analytical support.

The president of a residents’ association at a public housing project near Clean Path’s planned southern terminus said her neighborhood long has been plagued by poor air quality from nearby fossil-burning plants and the new line would provide relief. “I respectfully ask the commission to approve this project and move it forward. Our community can’t wait any longer.”

U.S. Sen. Charles Schumer and U.S. Rep. Dan Goldman, both New York Democrats, recited a list of benefits Clean Path is expected to offer and said priority status should be granted.

Con Edison Transmission recited a list of deficiencies it said exist in the Clean Path petition and said priority status should not be granted.

New York State AFL-CIO President Mario Cilento said: “We support designating this project as a priority transmission project because it will create good union jobs and help achieve the state’s emissions reduction goals.”

Multiple Intervenors, a collection of 55 large energy consumers statewide, faulted the 60-40 cost allocation split on several levels and urged a 75-25 split instead, placing most of the cost where most of the benefit would be realized: Zone J. And they said the 25% share should be spread across the entire state — not the rest of the state excluding New York City.

New York City urged priority designation for Clean Path for all the benefits it would provide but urged transparency on the cost of the project. It said it does not object “for now” to footing 60% of the cost, but said the split should be revisited if power begins to flow from downstate to upstate. (New York’s vision is that offshore wind farms someday may accomplish this feat.)

The city also wants clear indication that the 40% is to be spread across the rest of the state — not across the entire state including New York City.

The Census Bureau estimates New York City is home to 42% of the state’s residents.

NYISO estimates the generation mix on the New York City grid is almost 90% fossil-powered, while parts of the upstate grid are almost 90% emissions-free. ■

FERC Partly Accepts NYISO Order 2023 Compliance Filing

By Vincent Gabrielle

FERC on April 17 approved most of NYISO's proposed plan to comply with Order 2023, denying several of its proposed variations to the commission's *pro forma* rules and directing the ISO to submit an additional compliance filing in 60 days (*ER24-1915, ER24-342*).

Issued in July 2023, the order directed grid operators to revise their generator interconnection procedures to a "first-ready, first-served" cluster study process. It revised the commission's *pro forma* procedures while allowing for independent entity variations to account for regional differences.

For NYISO, this meant altering several of the order's time frames to align with its current Class Year study process, which already used a clustered approach, with queue position playing a limited role. For example, the ISO asked for 596 days

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to complete the overall study process, slightly more than the order's maximum of 585, and proposed that its customer engagement window be 70 calendar days, instead of the order's prescribed 60.

FERC accepted most of these because it found they "accomplish the purposes" of Order 2023 and would give both NYISO and its interconnection customers flexibility.

While several parties protested the proposed 596-day time frame, the commission said "NYISO's cluster study process has a unique study structure and requirements due to its proposed single, two-phase study process, which already incorporates restudies and does not have a separate facilities study. Thus, the timeline of the proposed NYISO cluster study process is appropriately compared to the timeline of *pro forma* study process including the *pro forma* LGIP facilities study timing, contrary to the contentions of" the protesters.

The commission, however, denied the ISO's proposal to not allow interconnection customers to use third-party consultants to perform study work. While it argued "that study elements need to be sequenced and managed in a particular order, NYISO does not explain why a third-party consultant could not perform its study within that time frame," the commission ruled. The variation would not "accomplish the purposes of the cluster study to increase efficiency and provide greater certainty to interconnection customers," it said.

Why This Matters

FERC found that NYISO overall complied with Order 2023, which should increase the speed and efficiency with which the ISO processes generator interconnection requests.

FERC also denied NYISO's proposal to apply penalties only at the end of the process, and not at the end of Phase 1. The commission said this did not provide a sufficient incentive for NYISO to complete Phase 1 in a timely manner.

And FERC denied NYISO's proposal to use a 300-day affected-system study timeline, saying it would bring the ISO out of step with neighboring regions that adhere more closely to the *pro forma* 150-day timeline. FERC told it to either revise the timeline to 150 days in its compliance filing or justify its proposal.

Finally, FERC rejected NYISO's method for allocating the costs of several studies as outside the scope of Order 2023, but without prejudice, giving the ISO the opportunity to file it as a separate proposal. ■

Firm Fuel Proposal Continues to Confuse NYISO Stakeholders

By Vincent Gabrielle

NYISO returned to the Installed Capacity Working Group with more *modifications* to the tariff language and general structure of its firm fuel capacity accreditation proposal, though based on the conversation at the meeting April 21, stakeholders are still skeptical of it.

The ISO made the changes in response to the criticism it received from stakeholders, including the Market Monitoring Unit. (See *NYISO's Firm Fuel Proposal Criticized*.)

But stakeholders peppered staff with hypothetical questions about how penalties and FERC referrals would be triggered and when. There were several times throughout the meeting that attendees asked for others to slow down so they could follow their line of questioning.

The firm fuel capacity accreditation project is an effort to incentivize generators to secure firm fuel contracts with their suppliers before winter, when the ISO and the New York State Reliability Council are worried about fuel shortages.

Generators wishing to elect as firm would commit to being able to run for 56 hours over any consecutive seven-day period in December through February. They would declare Aug. 1 of the prior capability year that they are opting to be firm. Failure to perform because of lack of fuel would result in a financial sanction. (See *NYISO Business Issues Committee OKs Firm Fuel Accreditation Concept*.)

Nikolai Tubbs, associate market design specialist for NYISO, explained the adjustments to the structure of the penalties, while Zachary Smith, senior manager of capacity and new resource integration market solutions, fielded questions from stakeholders.

For any given "winter performance month," the financial sanction would be assessed at a 1.5 multiplier if the reason for failure was within the generator's control. Generators would lose their firm fuel accreditation (i.e., adjusted down to non-firm) via the "settlement adjustment modifier" if failures occurred outside of the generator's control, or if the generator failed to have an operating plan or fuel contract in place for the whole month.

Generators would be required to notify NYISO by Dec. 1 if they were unable to secure firm fuel contracts. If something goes wrong during the winter, such as a fuel contract getting canceled, the generator is also obligated to inform the ISO. This reverts their status to "non-firm" by applying the settlement adjustment modifier.

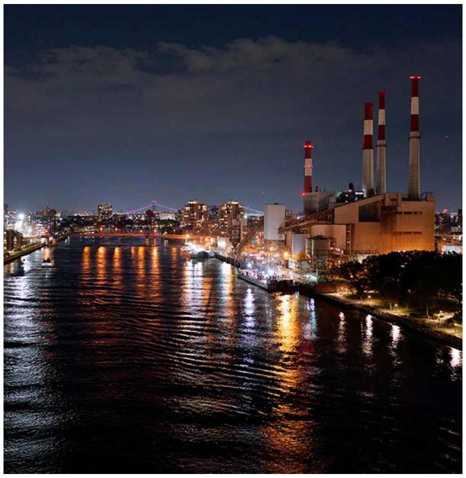
If NYISO learned that a generator failed to provide the required notice, the generator would be subject to the sanction with the 1.5 modifier and be referred to FERC. The ISO would also report to FERC if a generator supplied operating plans or fuel contracts that were "false or misleading."

In response to a question about what would happen if a generator had no contracts by Dec. 1 but did for January and February, Smith said that it would get the settlement adjustment (be compensated as non-firm) for all three months.

"There's no ability to cure," Smith said. "You potentially have the worse multiplier if you also fail to perform. If you have the contracts in place for December and January, but they are not in place for February, only February gets the settlement adjustment absent any of the other failures to perform."

Doreen Saia, a stakeholder representing generator interests, said this implied that a failure in December would cause a settlement adjustment no matter what, but a generator might want to have contracts in place because if it didn't, it would get hit with the worse financial sanction if it failed to perform.

"I think part of the problem is that this has been through so many iterations at this point that it would be a small miracle if the tariff said anything cogently or coherently," Saia said.



Ravenswood Generating Station in Queens, N.Y. | © RTO Insider

The conversation turned toward hashing out when NYISO would refer a generator to FERC. Smith explained that after a failure to perform, the ISO had the ability to ask to review a generator's contracts and plans, but that it might not always do so.

"If the entire gas system went out, I don't think we'd need to get to reviewing your contracts," Smith said as an example. "At that point, it clearly didn't matter what your contract said."

But in other cases, Smith said NYISO would need to open an investigation into whether the failure to perform was in the generator's control. Even in the case of an investigation, Smith would not state that the ISO would need to review contracts or plans in all cases. The ISO was reserving the right to look into plans and contracts in the event of a failure to perform.

"NYISO is not making a judgment call on anyone's plans, to whether or not they should have a penalty apply, absent a failure to perform," Smith said. After further discussion, Smith said NYISO did not want to be in the position of approving people's operating plans; it just wanted to audit plans if there was a concern.

"There's a lot of 'ifs' and 'thens' here," one stakeholder said at one point during the meeting. "Might I suggest you put this into a flow chart?" ■

What's Next

NYISO expects to file a final proposal with FERC this May.

Plan Lays out Steps for State-led Interregional Transmission in Northeast

Brattle Plan Seeks to Create the 'Missing Middle' in Transmission Development

By Vincent Gabrielle

The Northeast States Collaborative on Interregional Transmission released a *strategic action plan* April 28 for creating an interstate planning process for transmission projects that span the seams of their grid operators.

The collaborative comprises nine states — Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island and Vermont — and was formed with the goal of exploring "opportunities for increased interconnectivity" between ISO-NE, NYISO and PJM. (See *10 Northeastern States Sign MOU on Interregional Transmission Planning*.) (New Hampshire signed the initial memorandum of understanding creating the group but did not sign on to the plan.)

The plan, prepared by The Brattle Group, goes further than exploration and into concrete steps for soliciting projects and proposing them to the grid operators. It implicitly criticizes FERC's planning rules, including the recent Order 1920, for creating barriers to interregional projects.

"No process currently exists for groups of states spanning different transmission planning regions to take the various steps necessary to identify, evaluate, select and agree to share the cost of beneficial interregional transmission projects so they can be developed," the plan says. "Members of the collaborative have referred to the absence of such a process as 'the missing middle.'"

Brattle focused on what states can do in the short term — including over the next year — to identify beneficial interregional projects and "make them actionable through existing regional planning processes." Such projects would help states reach not just their long-term emission-reduction goals but also address their looming resource adequacy concerns.

"New York is pleased to be a part of this strategic partnership so that together with our fellow Northeast states, we can find more effective and affordable solutions to maximizing transmission opportunities that can both provide increased reliability as well as deliver additional clean energy to our grid," New York State Energy Research and Development Authority President Doreen Harris said in a statement.

Over the next year, the states will attempt to identify "low-hanging fruit" projects through a request for information. Brattle recommends the states ask the three grid operators to take on advisory roles in the process, as any project will need to be integrated into each of their transmission plans. It also suggests including NERC, "given its recent identification of interregional transmission solutions as necessary to ensure a reliable electric grid." (See *NERC Responds to Interregional Transfer Capability Study Comments*.)

Why This Matters

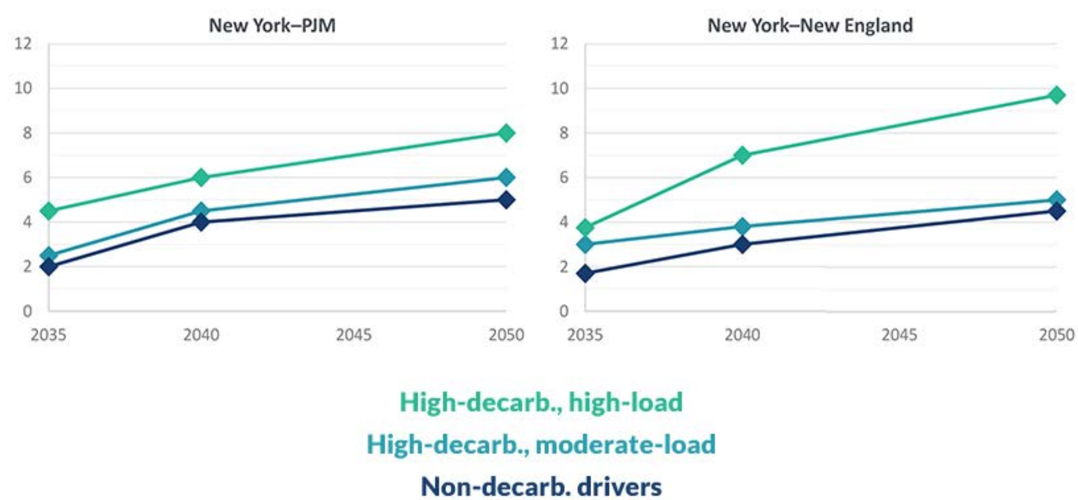
The states' action plan could create an entirely new, state-led transmission planning process.

Simultaneously, Brattle says, the states should consult with the grid operators and FERC on what, if any, tariff changes would be necessary to facilitate the interstate process.

The plan also includes goals for the end of 2027, including the development of HVDC design standards to facilitate an offshore transmission network and joint offshore wind procurements.

"Not having to build new power plants saves Marylanders money," Maryland Energy Administration Director Paul Pinsky said. "Increased regional transmission capacity can reduce the need for power plants that solely exist to meet peak demand, which are typically fossil fueled. … This collaboration illustrates why state-led climate action is so important to achieving our energy, environmental and economic goals."

"States across the Northeast share a common priority to ensure an affordable, reliable and sustainable electric grid," Vermont Department of Public Service Commissioner Kerrick Johnson said. "Transmission is at the heart of securing that energy future." ■



Estimated range of low-regrets transmission expansion needs (GW) | *The Brattle Group*

Stakeholders, NERC Respond to FERC Large Loads Investigation

ERO Says Co-location Provides Risks, Benefits

By Holden Mann and Devin Leith-Yessian

NERC joined a wide range of industry stakeholders responding to FERC's investigation of co-located large loads and their effect on grid reliability and costs for customers, while other stakeholders provided feedback on PJM's suggested approaches to co-location (*EL25-49*, *AD24-11*).

FERC launched the inquiry in February after rejecting an agreement the previous November between Amazon Web Services and Talen Energy to expand a data center co-located with the Susquehanna nuclear plant in Pennsylvania by modifying the generator's interconnection service agreement to reduce its output to PJM. (See *FERC Launches Rulemaking on Thorny Issues Involving Data Center Co-location*.)

Along with ordering PJM and its transmission owners to determine whether the RTO's tariff needed updates to accommodate the arrangements, the commission also sought comments on the larger issues. FERC is concerned that the arrangements could be developed in a way that is not fair for other customers, and that co-location could cause issues for reliability and resource adequacy similar to an event in July 2024 in which a transmission line fault in Virginia led to 1,500 MW of load reduction, all from data centers. (See *NERC Report Highlights Data Center Load Loss Issues*.)

In its *comments*, NERC highlighted the ERO's efforts to address the reliability challenges of co-located large loads. The organization cited its *report* on the 2024 event as well as its creation of the Large Loads Task Force (LLTF) in August 2024. Reporting to the Reliability and Security Technical Committee, the LLTF has a goal of creating two white papers and one reliability guideline before June 2026 on the identification and mitigation of risks, along with guidance for "improvements in modeling, analyses, coordination and data collection, real-time monitoring and event analysis."

Discussing the recent testimony of NERC Chief Engineer Mark Lauby at FERC's April open meeting, where topics included the 2024 incident as well as similar events in Virginia and Texas, NERC observed that co-located large loads may provide benefits to reliability as well as risks. The presentation was attached to NERC's filing as an appendix.

> **Why This Matters**
>
> NERC and other stakeholders have expressed growing fears about the reliability risks posed by large loads co-located with generation while noting they may also present opportunities to reduce energy loss from transmission and improve coordination.

"Proximity between large loads and power generation sources can reduce energy loss while improving transmission reliability [and fostering] improved coordination, leading to better load management and reduced strain on the" grid, NERC said. "Grid stability may also be enhanced if the proximity created flexibility to adjust demand during critical conditions."

The ERO's filing also mentioned the risks posed by co-location, such as the possibility that system operators may not have visibility into a co-located large load, leaving them unable to perform reliability analysis. This could lead to "risk of thermal overloads and voltage or stability issues." Large loads can also experience fluctuations during faults or switching that operators may not be able to anticipate.

NERC noted that its Board of Trustees solicited input from the Member Representatives Committee and industry stakeholders ahead of a panel on large loads at its February meeting. In response to the panel discussion and input, the board directed NERC to develop an action plan to identify and address the risks of large loads. This action plan will be due at the board's next meeting May 8.

Other respondents shared NERC's reliability concerns. Consumers' Research, a nonprofit consumer advocacy group, cited NERC's *2025 Long-Term Reliability Assessment*, which said many parts of North America could face resource adequacy challenges in the next 10 years, along with FERC Chair Mark Christie's warnings that "America is facing a reliability crisis driven by the dangerous pace of retirements of dispatchable generation units."

The group urged FERC to ensure that co-location is accomplished without exaggerating these reliability issues. Measures to achieve this goal could include requiring the parties involved to maintain a reserve capacity of dispatchable power for ratepayers, and that they "have no targets or commitments for net zero or any related low-carbon goals." CR said such commitments "harm consumers by artificially weakening the market for dispatchable power."

A joint comment by Suzanne Glatz of Glatz Energy Consulting and Abraham Silverman, a research scholar at Johns Hopkins University, referred to NERC's 2023 Reliability Risk Priorities Report, which warned that "new loads," including data centers, cryptocurrency mining and artificial intelligence, "can emerge and grow faster than generation and transmission can be built." They suggested that FERC "strongly consider a co-location 'safety valve' that ensures that co-location does not drive PJM into shortage conditions."

Modifications Suggested to PJM's Approaches

PJM filed its initial response to FERC's investigation in March, laying out three approaches to co-locating load already permissible under the RTO's tariff and outlining five more that could be developed under more possible configurations or limitations imposed by state laws.

Multiple stakeholders responded to PJM's comments with their own takes on the RTO's plans, or on the theme of co-location in general. The Data Center Coalition commented that co-located load configurations can allow large consumers to avoid long interconnection delays by not relying on congested transmission infrastructure. It argued that many of the issues raised around co-location are more related to tightening capacity supply and demand.

"Co-location can reduce transmission congestion, avoid costly infrastructure buildouts and enable the more efficient interconnection of new resources. But amid tightening margins, it has become a stand-in for deeper anxiety about supply adequacy and planning accuracy," the coalition wrote.

It requested that the commission initiate settlement judge proceedings to allow for more thorough discussions and stay the investigation for 90 days. It also recommended that PJM make several changes to its load forecasting, including verifying the commercial readiness of large load additions and increasing transparency to ensure that such additions do not create reliability issues.

Constellation Energy argued that requiring data centers to be classified as network load in front of generators' meters has led to interconnections taking years to complete and has exposed data centers to moratoriums on new load interconnections, as seen in Ohio. While many consumers will prefer the reliability offered by PJM in exchange for being subject to transmission charges, the company said many are willing to forgo the reliability of full grid service in exchange for speedier interconnection.

In some cases, Constellation said, those customers might be willing to accept backup service from the grid once network upgrades have been completed.

Responding to several paradigms PJM laid out for the commission to explore in the RTO's comments, Constellation said it is opposed to the "bring your own generation" route, which would prioritize generation interconnections part of a co-located load configuration. The company argued that would discriminate against existing generation and undermine capacity market incentives.

Under options in which the load is behind the generator's meter, Constellation said it may be appropriate for it to pay some ancillary services, such as regulation and black start, but subjecting the load to network integration transmission service charges would require it to use services it would not otherwise. (See *PJM Responds to FERC Co-located Load Investigation*.)

The company asked the commission to either accept modified variants of the co-located options proposed by PJM or initiate a time-limited settlement judge proceeding to consider alternatives.

Talen Energy's Susquehanna Steam Electric Station located in Salem Township, Pa. | © *RTO Insider*

PJM stressed in its March filing that while the options it presented are routes the commission could explore, it does not view them all as equal or feasible. It was particularly skeptical of two configurations exempting co-located load from transmission charges when protective mechanisms have been installed to prevent the load from receiving energy from the grid. Such mechanisms could fail, the RTO wrote, and the load would nonetheless continue to consume ancillary services, such as regulation.

Echoing the Data Center Coalition, Constellation said co-located load is being blamed for broader issues with PJM's capacity market and generation interconnection process. It said the RTO's Reliability Resource Initiative bolsters resource adequacy by adding 50 projects to the next queue cycle that can quickly bring capacity to market, and further improvements can also be made to the interconnection study process.

"The commission should determine whether there are additional tools to address near-term capacity needs while reinforcing PJM's capacity market, which is already sending strong signals for new entry (or for delaying retirement of existing resources)," it wrote.

Constellation encouraged the commission to establish a flexible set of rules for developers to follow when pursuing co-located configurations, saying there are many ways that load and generation can be combined.

"Allowing load to select a configuration that best serves its needs will enhance national security and national economic competitiveness by speeding connection for those new customers who need to connect quickly and will save existing customers money by minimizing system upgrades," the company wrote.

Generation developer BrightNight said the commission should establish a *pro forma* agreement and process for co-located configurations that allows flexibility for the three configurations that may be pursued: fully islanded generation and load; flexible load or demand response; and load that may rely on the grid for backup service when on-site generation is unavailable.

"Data center developers, generation developers and system planners cannot make long-term decisions without understanding what co-location arrangements the commission will accept," BrightNight wrote. "Standardizing procedures and agreements would give developers and planners certainty, reduce opportunities for undue discrimination or preference, reduce disputes and, hopefully, expedite the development of data centers and needed generation."

Public Interest Organizations Warn of Consumer Costs

Several public interest organizations jointly argued that certain co-location configurations could push network upgrade costs to consumers and cause reliability issues if they fall through cracks in PJM's load forecasting.

The comments were signed by Appalachian Voices, Clean Air Task Force, Earthjustice, the Environmental Defense Fund, PennFuture and the Sierra Club.

They wrote that the three processes PJM uses to identify transmission violations prompted by co-located configurations — necessary studies, TO load integration studies and the Regional Transmission Expansion Plan — fail to take a holistic look at projects' impacts. The necessary studies exclusively look at changes to the generator's interconnection service agreement, while the latter two assign any identified upgrades to network load.

They also highlighted that PJM has not allowed batteries to go through the necessary studies process because the charging cycle can act like load, but the RTO has proposed to apply it to co-located configurations.

The organizations wrote that accelerated data center load is expected to cause wholesale costs to rise significantly, and co-located load configurations sought by developers would further shift costs to consumers. They also argued it could create opportunities for generators to engage in market power manipulation by withholding capacity from PJM to supply co-located load.

"The commission cannot ignore the current realities in PJM: already sky-high capacity prices, as well as an extremely backlogged interconnection queue, supply chain issues for new resources (both generation and transmission) and limited available transmission capacity that further drives up the cost of interconnection," they wrote.

"Each of these conditions makes new entry challenging, and if left unaddressed, very expensive. Allowing the key drivers of the tight supply margins — large load customers — to avoid and exacerbate these challenges and associated costs by sequestering access to existing generation would be a cost shift of extreme magnitude."

TOs, cooperatives and municipal providers opposed changes to PJM's tariff, jointly commenting that existing processes may not be preferable for co-located configurations, but they are not discriminatory or unjust and unreasonable and therefore changes cannot be compelled by FERC using a Federal Power Act Section 206 investigation. The comments were submitted by Exelon; American Electric Power; the city of Hamilton, Ohio; Southern Maryland Electric Cooperative; Duke Energy; and Dominion Energy, among others.

"Those end-use load connection processes, governed by the states and fully consistent with the PJM tariff, are available to all, and those processes work. Moreover, the transmission service provided to co-located load under the PJM tariff is available to all on a nondiscriminatory basis," they wrote. "Nowhere in the record is there an allegation —let alone evidence — that the current PJM tariff impedes the development of or service to any load, co-located or otherwise."

They also argued that co-located configurations should be prohibited from being classified as behind-the-meter generation, citing PJM's statements that the ruleset was designed for smaller configurations and the load would not be properly measured by the RTO, even though it uses the transmission system. ■

FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor

By Devin Leith-Yessian

Pennsylvania Gov. Josh Shapiro | *Shutterstock*

FERC on April 21 approved a PJM proposal to limit capacity prices to between $175 and $325/MW-day for the next two Base Residual Auctions (BRAs), resolving a complaint from Pennsylvania Gov. Josh Shapiro alleging there was potential for prices to soar above what is necessary to maintain resource adequacy (*ER25-1357*).

The commission found that PJM's capacity market is facing conditions outside the bounds considered in the 2022 Quadrennial Review, noting the RTO's filings highlighted a confluence of a tightened auction schedule, load growth, generation deactivations, a backlogged interconnection queue and exogenous constraints to resource entry such as permitting and supply chain challenges.

FERC said PJM and the Shapiro administration proposed a temporary measure to add a "collar" to the clearing prices for the 2026/27 and 2027/28 capacity auctions while the RTO drafts long-term market changes in the current Quadrennial Review and implements a cluster-based approach to studying projects in its interconnection queue. (See *PJM, Shapiro Reach Agreement on Capacity Price Cap and Floor*.)

While the price band would be initially set at $175 to $325/MW-day, those values would be readjusted annually based on the accreditation of the reference resource — a dual-fuel combustion turbine generator — and therefore could change.

"We agree with PJM that the price cap and price floor will operate together to narrow the range of potential capacity price outcomes, which will reduce the price volatility under the existing" variable resource requirement curve, FERC said. "In accepting PJM's proposal, we recognize that several commenters representing both suppliers and consumers support the proposal as a balanced, time-limited approach, and that several additional commenters do not oppose PJM's proposal."

The proposal was supported by the New Jersey Board of Public Utilities and Pennsylvania Public Utility Commission, as well as generation owners and utilities including Talen Energy, Constellation Energy, Calpine and Dominion Energy, who commented that it represents a temporary measure to keep costs reasonable while new market rules are developed through the Quadrennial Review.

In his complaint, filed Dec. 30, 2024, Shapiro argued that between a backlogged interconnection queue and an auction schedule that has been repeatedly delayed to the point that the 2026/27 BRA is set to be conducted within a year of the start of the corresponding delivery year, developers would have no opportunity to respond to high prices by bringing new resources to market.

In line with PJM's proposal and statements to stakeholders when it was

Why This Matters

The commission's approval of PJM's proposal to institute a $175/MW-day floor and $325/MW-day cap on capacity prices for the next two auctions, which follows several filings redesigning aspects of the market, represents a temporary measure to keep costs reasonable while new market rules are developed through the Quadrennial Review.

presented to the Members Committee in February, the commission's acceptance of the filing included the dismissal of Shapiro's complaint as moot. (See *PJM Presents Capacity Price Cap and Floor to Members Committee*.)

A maximum price point has been a part of the Reliability Pricing Model (RPM) since its inception, but the proposal represents the first instance of a price floor being included in auction rules. The Independent Market Monitor and North Carolina Utilities Commission protested against the minimum price, arguing it could require consumers to procure unneeded capacity.

The Monitor also argued that curtailment service providers may seek to take advantage of the price floor by offering a large amount of demand response resources, which the commission found out-of-scope as PJM proposed no changes to DR rules.

PJM said the floor would counterbalance the diminished maximum price by providing revenue certainty to market sellers, which would support near-term investments in capacity. It also wrote that it would be unlikely that the marginal resource would clear at $175/MW-day or less given the tight market conditions and that the 2025/26 BRA cleared at nearly $270/MW-day.

Shapiro also supported the price floor, arguing that it would address the market uncertainty sellers are likely to face over the next two auctions.

The commission wrote that PJM demonstrated the capacity shortage seen in the 2025/26 auction — when just 20.7 MW of offered capacity did not clear — is likely to continue for at least the next two years. It noted that PJM anticipates 4 GW of load growth in the 2026/27 delivery year and 6 GW the following year.

"Given the facts and circumstances presented in this record, we find that the benefits of PJM's proposed temporary price floor outweigh the potential risk of over-procurement, and therefore find PJM's proposal for a temporary collar is just and reasonable," FERC said.

The commission rejected a protest from coal trade association America's Power that the proposed maximum price would prompt planned resources to drop out of the queue and cause existing generation to deactivate or seek to offer capacity to other regions. It cited analysis of resources that have deactivated in the past after operating on reliability-must-run agreements with cost-of-service compensation, finding that a $500/MW-day clearing price would make half of those resources economic, while a $325 clearing price would make them all uneconomic.

The commission wrote that cost-of-service is not comparable to the revenues a resource receives from PJM's capacity, energy and ancillary service markets.

FERC's order follows several others approving PJM proposals to rework elements of its capacity market, including requiring intermittent and storage resources to submit capacity offers, including the output of units operating on RMR agreements in the supply stack and reworking how gas resources are modeled in the winter. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse Changes to Black Start Compensation

The PJM Markets and Reliability Committee on April 23 endorsed a *proposal* to rework how resources are compensated for providing black start service the RTO says will provide more predictable revenues for participating market sellers.

The change was passed with 80% sector-weighted support at the MRC and was endorsed by the Members Committee as part of its consent agenda.

The package of changes replaces the zonal net cost of new entry in the base formula rate (BFR) equation — used to determine compensation for most black start resources — with a five-year average of the RTO-wide net CONE. The averaged value will be used for the 2025/26 delivery year and adjusted according to the Handy-Whitman index every year thereafter, with the results to be posted by March 31.

PJM's Glen Boyle said the RTO's goal was not to increase or decrease compensation relative to past years but to keep revenues static to avoid having resources exit the market. When PJM seeks additional black start capability through requests for proposals, he said the new resources tend to require upgrades to make them capable of providing the service, which results in them being compensated through the capital recovery factor (CRF). That carries potential for significantly higher costs than maintaining resources being compensated through the BFR.

During the first read of the proposal in March, Boyle said 29 resources have stopped providing black start service since 2019, 26 of which were replaced through RFPs. All but two of the new resources required upgrades and were initially compensated through the CRF. (See "PJM Presents 1st Read of Proposal to Rework Black Start Compensation," *PJM MRC/MC Briefs: March 19, 2025*.)

Independent Market Monitor Joe Bowring said PJM should carefully consider whether black start resources are being fairly compensated rather than seek what he called an arbitrary change to the formula. In past meetings, he noted that PJM first broached the subject after it determined the scheduled shift to a combined cycle reference resource would cause the net CONE to fall significantly. PJM has since received FERC approval to continue using a combustion turbine as the reference resource. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

The primary purpose of the reference resource is to select the model resource on which capacity market parameters are based — a structure Boyle said PJM does not believe has any relevance to black start compensation. He said the proposal will break the connection between net CONE and black start.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said he agrees with the aims of seeking additional transparency and consistency in black start rates, but many advocates are concerned that disentangling net CONE and black start by using the five-year average does not advance those goals.

"Is there a better way to do this? Make sure it's fair, and develop a basis to make it fair," he said.


Glen Boyle, PJM | © *RTO Insider*

PJM Presents Proposal to Add Transparency to ELCC

PJM presented a *proposal* aiming to provide additional transparency in how it determines effective load-carrying capability (ELCC) class ratings and how those values translate in resource accreditation in the capacity market.

The package received unanimous support from the ELCC Senior Task Force in a March poll.

It would require PJM to publish an annual report detailing the class ratings development process, the assumptions guiding the process and an explanation of the results. It would also include an analysis of sensitivities PJM deems relevant. A nonbinding schedule would also be developed to show how the accreditation inputs for each auction are used, including dates for releasing class average and unit-specific performance adjustments.

PJM would also hold stakeholder meetings prior to developing the study to review the assumptions it is considering using and discuss how changes in the data driving ELCC may affect the outcomes. Similar sessions would be held after the publication to review the results.

The package would also require PJM to share unit-specific performance data going back to June 2012 with respective generation owners through its Generator Availability Data System.

The proposal would revise Manual 18: Capacity Market, Manual 20A: Resource Adequacy Analysis and Manual 33: Administrative Services for the PJM Interconnection Operating Agreement. An endorsement vote is planned for the MRC's meeting May 21.

Transparency is one of several charges the ELCCSTF was given when it was formed in late 2024, along with the inputs and process PJM uses to determine ELCC values and how investments a generation owner makes in their units can lead to increased accreditation. It is also *considering* how the shift toward winter risk under the expected unserved energy approach to modeling reliability risks in the ELCC paradigm interacts with the focus on summer peak loads when determining zonal capacity emergency transfer limits.

First Reads on Manual Revisions

PJM's Ryan Nice *presented* a first read on revisions to Manual 1: Control Center and Data Exchange Requirements that includes adding new data requests to the Generation Scheduling Service table.

The revisions would add the Cold Weather Checklist and Generation Periodic data from the Dispatcher Application and Reporting Tool to the table. They would also align the manual with NERC Standards IRO-010 and TOP-003, both of which are effective July 1 and include a recommendation that changes to transmission owners' backup functionality operating plans be certified with PJM by Dec. 31, rather than within 60 days.

PJM's Suzanne Coyne *presented* a slate of manual revisions to conform to FERC's approval of the RTO's rules for determining clearing prices during a market suspension (*ER23-1431*). (See "First Reads on Manual Revisions," *PJM MIC Briefs: April 2, 2025*.)

The changes to Manuals 6, 11, 28 and 29 would establish three sets of rules for determining prices based on whether a suspension lasts less than six hours, between six and 24 or longer. Shorter suspensions would use the average real-time prices for each hour prior to and following the outage. For moderate-duration events, day-ahead prices would be used if available; otherwise, real-time prices would be used. For suspensions exceeding a day, an aggregate supply curve would be developed.

If endorsed by the Market Implementation Committee on May 7, the manual language would be voted on by the MRC on May 21.

Members Committee

Stakeholders Discuss Posting Board Election Tallies

The Members Committee discussed whether it would be appropriate for PJM to publish the threshold by which candidates for the RTO's Board of Managers were elected or rejected. Currently PJM states only if a candidate was elected, not exactly how the vote went.

The subject was broached by Carl Johnson, representing the PJM Public Power Coalition, who said there is interest in having more public information about board elections given members' dissatisfaction with decisions the board made on revisions to the Consolidated Transmission Owners Agreement (CTOA) last year. The MC rejected endorsement of the proposal to shift filing rights over the Regional Transmission Expansion Plan (RTEP) from membership to the board, after which the board opted to file the changes with the commission later that year. FERC ended up rejecting the revisions. (See *FERC Rejects PJM and Transmission Owners' CTOA Proposals*.)

Representing two members of the Other Supplier sector, Bruce Bleiweis, principal of BN Energy Advisor, said transparency is a core pillar of PJM's responsibilities and having more information about the board vote would support that.

PJM CEO Manu Asthana said he does not see any reason why the tallies could not be published. The vote is conducted by a third party to ensure the RTO cannot see how individual members voted, and the sector-weighted results are conveyed to staff. Past practice has been that sector-weighted information is not shared with the public or the board.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said he is concerned that releasing information about how each sector voted could put targets on sectors' backs when elections may be contentious.

Exelon Director of RTO Relations Alex Stern said he does not want board members or PJM to ever see members' votes, but it does make sense to have more transparency around board elections. ■

— Devin Leith-Yessian

MPEC Members Celebrate Markets+ Funding Order

FERC Approval Puts SPP Day-ahead Market in 'Go Time,' MPEC Chair Says

By Tom Kleckner

DENVER — FERC's approval of SPP's Markets+ funding agreement and its recovery mechanism came as interested participants in the Western centralized day-ahead market were meeting with the snow-capped Rockies as a backdrop.

They cheered when they were notified of FERC's decision during their April 22 Markets+ Participant Executive Committee (MPEC) meeting. Then they went back to work. (See *FERC Approves SPP's Funding Plans for Markets+*.)

"We're in go time," MPEC Chair Laura Trolese, with The Energy Authority, told *RTO Insider*.

"Getting the FERC approval was super exciting. We got FERC approval both on the Markets+ funding agreement but also the final order on the last items last week," she said, alluding to the commission's April 17 approval of SPP's final compliance filing for Markets+. (See *FERC OKs Final SPP Markets+ Compliance Filing*.)

"We needed those two things to move forward with implementation activities and timeline," Trolese added.

Joe Taylor, with Xcel Energy subsidiary Public Service Company of Colorado (PSCo), said his company was pleased with the approval, which he said was not unexpected. PSCo filed a request in February with the Colorado Public Utilities Commission to join Markets+ and recover costs from its funding agreement. (See *PSCo Seeks to Join SPP's Markets+*.)

"We made our filing assuming that [SPP's request] was going to be approved, and it was," Taylor said. "It was an expectation that the funding agreement would be approved, because then we can go forward and participate and execute that agreement."

SPP's Carrie Simpson, who broke the news to MPEC, recognizes that Markets+ development faces a long and winding road ahead.

"It's just another important milestone. We're grateful for it, and it will set us up for Phase 2," she told *RTO Insider*.

FERC issued two orders in approving SPP's proposed funding mechanism:

- The first accepted SPP's proposed $150 million Phase 2 funding agreement as a rate schedule under the Markets+ tariff, effective March 24 (*ER25-1372*).
- The second granted SPP's request to issue debt securities to cover the agreement and fund the market's implementation over three years until its go-live date, effective April 21 (*ES25-33*).

SPP has set the go-live date as Oct. 1, 2027.

In its Feb. 21 filings, the grid operator told FERC the funding agreement will ensure those participants that benefit from the market will fund its development and share in overhead costs.

SPP said the funding agreement is a freely negotiated contract between the RTO and each of the eight entities that have agreed to participate in Phase 2 and provide collateral to SPP's lender equal to the amount of their obligations: Arizona Public Service, Bonneville Power Administration, Chelan County (Wash.) Public Utility District (PUD), City of Tacoma, Grant County (Wash.) PUD, Powerex, Salt River Project and Tucson Electric Power.

The funding agreement requires the entities to provide the collateral backstop to SPP's lender in supporting the financing the RTO will use to develop Markets+'s

Joe Taylor, Xcel/PSCo | © *RTO Insider*

systems, processes and operations during implementation. The collateral is equal to the amount of the entities' Phase 2 obligations.

SPP says the cost to repay the financing will be incorporated into Markets+ rates and will relieve participants from the burden of providing "large sums of money to directly fund Phase 2." SPP is splitting the phase into two stages, with participants required at first to provide collateral equal to two-thirds of their Phase 2 obligation. The first stage expires six months after the initial funding threshold has been met, at which point participants must provide collateral equal to their full Phase 2 obligation.

As a federal agency, BPA — the major industry player in the Pacific Northwest — can't post collateral to back up its commitment. BPA will instead provide a letter of assurances from its COO that explains its authority to enter into the agreement and statutory obligation to pay part or all of its Phase 2 obligation, whichever is effective at the time.

5 Steps of Funding

The funding agreement is composed of five stages:

- When the funding threshold is met by entities that are or represent at least

Why This Matters

Interested participants in SPP's Markets+ day-ahead market are celebrating FERC's approval of a funding agreement and its recovery mechanism. The approval clears the way for the RTO and its new stakeholders to focus their attention on Phase 2, when they will develop the software, systems and process for their implementation.

two contiguous balancing authorities and not less than 200,000 GWh of 2023 net energy for load execute the funding agreement. That was met Feb. 13 when funding agreements were first signed. (See *SPP Secures Funding to Begin Markets+ Phase 2*.)

- When financing conditions are met with the financing's regulatory approval and when SPP executes the loan agreement.
- When participants provide collateral to back financing determined by their Phase 2 obligation in the form of cash or a letter of credit. The obligation is the participant's pro rata share of Markets+'s total cost less its Phase 1 and post-Phase 1 payments. (Funding participants withdrawing from the agreement must pay their Phase 2 obligation to SPP, protecting the remaining participants from the withdrawal.)
- When SPP obtains funds drawn from the loan or received under the funding agreement to acquire, create and/or modify the systems and processes required to implement Markets+.
- When financing costs are repaid after go-live. Phase 2's implementation costs will be incorporated into market rates charged to participants through a tariff schedule. SPP will repay the financing as the costs are recovered and the lender authorizes the release of excess collateral on an annual basis. The funding agreement will terminate when SPP notifies participants that the financing has been fully repaid, including all principal, interest and fees.

FERC found the funding agreement will provide a framework for SPP to begin the market's development phase. It said the funding participants' provision of collateral and Phase 2 cost-recovery ensures that only Markets+ beneficiaries — and not SPP RTO members — are responsible for the development costs.

The commission declined to direct SPP to provide a commitment that its RTO members will not be responsible for the financing costs. "SPP has already provided sufficient commitment that this will be the case," FERC said.

"In addition, the funding agreement itself does not implicate SPP RTO members in the event of a default or withdrawal of a funding participant," the commission added.


The Energy Authority's Laura Trolese, MPEC's chair, confers with SPP's Carrie Simpson. | © *RTO Insider*

FERC rejected several concerns raised by public interest organizations (PIOs) around BPA's connection to the agreement. The groups, which include Northwest Energy Coalition, Idaho Conservation League and Public Citizen, said the agreement would effectively obligate Bonneville to participate in Markets+ ahead of issuing its formal record of its participation decision (ROD) on its day-ahead market participation because it would be on the hook for providing up to $40 million in implementation costs to SPP even before releasing the ROD. They contended that either SPP's filing had mischaracterized BPA's commitment to Markets+ or the agency had been engaging in a "sham" process regarding its day-ahead market decision.

"We disagree with PIOs that the funding agreement requires Bonneville (or any other funding participants) to participate in Markets+," FERC wrote. "As PIOs acknowledge, the funding agreement requires a funding participant to pay its Phase 2 obligations in the event it decides to withdraw from the funding agreement; however, the funding agreement does not obligate any funding participant to proceed with Markets+ participation."

The commission found in its second order that while SPP didn't meet FERC's interest-coverage ratio threshold, the grid operator cited other factors that gave it a "sufficient alternative basis" to determine that the RTO had "reasonable prospects for being able to service the proposed new debt securities." FERC said the Markets+ tariff, approved this year, will provide for the recovery of all of the proposed indebtedness' financing costs.

"Furthermore, we note that SPP has secured commitments from the funding participants, which guarantees that SPP will be able to repay its debt obligations related to Markets+," the commission wrote. It added that SPP's plans to recover the implementation's costs will not make its RTO members responsible for the market's costs.

FERC set the loan's interest rate not to exceed the total of a one-month secured overnight funding rate and a spread determined by the amount of cash collateral obtained from the funding participants. ■

After Hitting Milestones, Markets+ Participants Advance on Phase 2

SPP Sets October 2027 Live Date, Deadline for BAs to Join

By Tom Kleckner

DENVER — Markets+ stakeholders will have little opportunity to ease up in coming months despite a wave of favorable developments for the market.

Those include FERC's recent approval of the *Markets+ tariff*, funding agreement and a pair of compliance requests, as well as participants agreeing on most of the *market protocols*.

SPP has officially set Oct. 1, 2027, as the go-live date for *Markets+*, its centralized, day-ahead offering in the Western Interconnection. Between now and then, much will happen, with Sept. 1, 2025, emerging as a key date. That is the deadline for balancing authorities to join in time to be a part of the market when it goes live.

"It's going to be really busy between now and Oct. 1 of 2027," The Energy Authority's Laura Trolese, chair of the Markets+ Participant Executive Committee, told *RTO Insider* on April 23. "The utilities and [independent power producers] within the BAs that are joining in the first tranche are going to need to get ready, register, figure out who their market participants are going to be and figure out a lot of different things to move forward with implementation. When an BA joins, now all the loads and resources within that BA are required to register and participate."

Before then, SPP will begin designing and building the market's systems and kicking off network and commercial modeling, while stakeholders will begin training on the RTO's systems.

Puget Sound Energy's Jessica Zahnow explains proposed meeting attendance requirements and use of proxies. | © *RTO Insider*

Why This Matters

With the tariff approved and funding agreement in place, SPP and potential Markets+ participants are well into the second phase of the market's development and focused on Sept. 1 — the deadline for Western balancing authorities to join the market.

And with MPEC's endorsement, the Markets+ Change User Forum (MCUF) will hold its first monthly meeting as Phase 2 gets serious. SPP staff said the MCUF, based on similar groups in previous market developments, will serve as an implementation forum for the Markets+ protocols.

"This is kind of exciting, because this is where it starts," said Don Martin, SPP customer relations manager. "It is where you get our people and everybody's people together. This is where your [energy management systems] team will be talking to these folks. This is where your IT folks will be talking or registering assets."

The forum is holding its first virtual meeting *May 6*, five days after Phase 2 starts.

MPEC also endorsed a seams strategy and roadmap *paper* that lays out focus areas in the future development of polices and governing documents related to seams between Markets+ and neighboring markets and entities. It also documents a "desired end state" for market-to-market relationships with neighboring markets.

Stakeholders unanimously approved the recommendation.

The only motion that received a dissenting vote during the two-day meeting was a recommendation governing meeting attendance and the use of proxies from the Markets+ Interim Governance Task

Force (MIGTF). Public interest organizations and other entities with small staffs pushed back against the recommendation that representatives on a working group or task force who miss three straight meetings or appoint a proxy for six straight meetings can be removed from the group by its chair. The MPEC and the Markets+ State Committee (MSC) would be excluded from that provision.

"Those groups that are maybe more capacity resource-constrained tend to rely heavily on proxies in order to maintain effective and consistent participation," said Renewable Northwest's Kavya Niranjan, who cast the lone "no" vote. "Our concern with this policy is not that we are not in disagreement with the intention. We feel that, because it can be overly prescriptive, that PIOs that are still trying to engage meaningfully might accidentally or unintentionally get caught up in the overly prescriptive nature of this policy."

The MIGTF has debated the issue since August 2024, much to the consternation of its chair, Puget Sound Energy's Jessica Zahnow, who said she just wanted to set clear expectations for attendance and participation.

"When our task force formed eight months ago, I got the list of the six items [to set expectations for recommendations] and I saw attendance policy. I thought, 'Oh, that's a slam dunk. That one's going to be easy. Some of these other things are going to take some work, but this one will be easy,'" she recalled. "It hasn't been easy, but we have learned a lot."

Snohomish Public Utility District's Joe Fina complimented the task force on its effort and their work developing a stakeholder-driven approval process unlike those of other grid operators.

"I was very impressed with the interactions of the task force, the good faith that I think everyone was working under in trying to resolve the concerns that were issued," he said. "I'm so glad to see kind of the end product here, after being aware of all of the process. I'm not aware in any of the other markets where they go down as deep into the working groups, and they have a similar thoughtful process, proxies and ability. I think that other markets will be looking at this as kind of the model as to how they deal with the similar issue and the work level."

Maurice Moss, ACP | © *RTO Insider*

GHG, Other Protocols Endorsed

In a series of unanimous votes, MPEC approved more than a dozen-and-a-half chunks of the tariff's remaining protocol language.

That included sections brought forward by the Markets+ Greenhouse Gas Task Force (MGHGTF), which is dealing with one of the more complex protocol sections. The task force began working on GHG pricing protocols in November 2024 after it completed GHG tracking and reporting protocols and developed an appendix providing guidance on creating and submitting mitigated energy offer calculations.

The MGHGTF plans to draft its final pieces of protocol language — focusing on unspecified-source imports and import interchange transactions — in the months ahead, while also ensuring that the market's implementation is consistent with state regulations.

"There are several things that we are continuing to tackle," said the Public Generating Pool's Mary Wiencke, who chairs the group. "I would not want this to be reflected as the GHG Task Force being behind. The GHG Task Force has been working very hard and diligently, but this is a new and novel design, so there are a lot of complex elements to figure out. We still do have some outstanding plan items and action items that we are continuing to work through it."

She said the Washington State Department of Ecology has an open rulemaking on electricity markets, which has tightened the focus on the group's work.

"Folks in Washington are very engaged in that process to make sure that what is being developed by the task force is consistent … in terms of the market design reflecting the state regulation and the state regulation reflecting the market design as well," she said.

The MPEC agreed to reappoint all stakeholder group chairs and vice chairs through its Aug. 12 meeting in Portland. Trolese noted all stakeholder representatives were appointed to two-year terms in April 2023; this will allow a smoother transition when Phase 2 begins with the August meeting, she said.

The MPEC also endorsed three new members for the working groups:

- Damon Skondin (Tucson Electric Power) for the vacant investor-owned utility seat on the Markets+ Transmission Working Group.
- Richard Doying (Grid Strategies) and Caitlin Liotiris (Western Power Trading Forum) for the vacant independent seats on the Markets+ Seams Working Group.

Blank on Budget, PSCo Filing

The MSC, composed of regulators from 13 states, is asking for a $428,680 budget for 2025 to fund one full-time equivalent staffer at the Western Interstate Energy Board this year and retain the MSC's consultants. The MSC said that will enable the regulators to continue engaging in the market's development.

Eric Blank, chair of the Colorado Public Utilities Commission and previous chair of the MSC, told the MPEC the budget will be submitted to the *Interim Markets+ Independent Panel* for its approval.

Blank also said the PUC has a pending application from Xcel Energy's Public Service Company of Colorado seeking cost recovery and other approvals to enter Markets+. PSCo filed its request in February. (See *PSCo Seeks to Join SPP's Markets+*.)

"Although I can't say much about pending litigation, I can say that the Colorado PUC is committed to getting a timely decision made to provide greater certainty to SPP and the Markets+ participants," he said. ■

SPP Stakeholders Open Discussion on Affordability

By Tom Kleckner

HOUSTON — SPP staff have opened a discussion into affordability and the grid operator's proposed regionwide approach to improve decision-making and keep affordability as a key focus of the business strategy.

To that end, CFO David Kelley shared with the Strategic Planning Committee a draft definition of affordability that defines it as the ongoing pursuit of "delivering regional solutions at a cost that balances near-term financial impacts with long-term economic sustainability" in SPP's footprint.

He said during the SPC's April 16 meeting that the definition is supported by a model that incorporates transparency, proactive planning and stakeholder-driven decision-making to ensure costs and benefits are well understood and balanced over time.

Kelley invited the SPC's membership to meet with him and help refine the affordability model. Several were quick to respond during the meeting. They offered their initial thoughts on FERC's efforts to place affordability on equal footing with reliability, clarifying the definition of affordability to ensure it's easily understood, including regulators in the discussion, emphasizing the affordability of connecting in this region and defining where the committee will draw the line on affordability.

"It's very clear that FERC has put affordability on the same level as reliability. The previous FERC chairman made that very, very clear, and the current chair has not changed that view," Golden Spread Electric Cooperative's Mike Wise said. "So my encouragement is to keep affordability and reliability in the same sentence and the same focus, same level of concern."

"A lot of this looks through the lens of retail rates. That's actually complicated, and like all of us in this room, we will use consumer costs to support a point," said David Mindham, with EDP Renewables. "We've got to be careful that we're not using this to support our business interests, as opposed to the customers' interest."

Kelley said the genesis was the Finance Committee making it "abundantly clear" how important affordability was in presenting the budget, his first after being promoted to CFO.


SPP CEO David Kelley explains the focus on affordability as SPC Chair John Cupparo listens | © RTO Insider

Why This Matters

SPC members offered their initial thoughts on FERC's efforts to place affordability on equal footing with reliability:

- Clarifying the definition of affordability to ensure it's easily understood.
- Including regulators in the discussion.
- Emphasizing the affordability of connecting in this region.
- Defining where the committee will draw the line on affordability.

"This is intended to be something that is regional in nature. We as a regional organization, how would we view affordability, recognizing that every member in this room, and all 116 or 118 members that we have, would have their own unique view of affordability?" he asked rhetorically. "What is the lens that we will view the things that we're bringing forward, whether it's transmission, expansion plans or proposed changes to the [planning reserve margin] or changes to revolutionize our market? How are we viewing those things in terms of affordability?"

The conversation continued into the next agenda item, a discussion of short-term reliability projects (STRP) that was facilitated by board member Irene Dimitry. She said the number, size and cost of the projects have grown tremendously, triggering a need to rethink the board's treatment of these projects and how to make more informed STRP decisions.

CEO Lanny Nickell clarified that a 30-day comment period was to gather SPC members' feedback on proposed considerations and not whether STRPs should continue to be assigned to incumbent transmission owners or put out for competitive bids.

"Personally, I believe this issue falls squarely in the reliability and affordability balance that we just talked about, and it sits squarely with the board," board Chair and SPC Chair John Cupparo said after the discussion closed. "We didn't ask for that responsibility, but we got it as part of [FERC's] Order 1000 process. If the $3.2 billion [of STRPs] that we just approved in February was a one-time event, you might be able to justify leaving everything as is.

"But it appears the 2025 ITP may be as big, if not bigger, and we don't know what 2026 looks like. From my perspective, if this is a regular occurrence, we as a board have an obligation to define what safeguards mean and how we plan to execute that role."

SPP Waits on Executive Orders

Kelley told the committee members interested in the grid operator's perspective on the Trump administration's energy executive orders issued April 8 will have to wait until the SPC meets virtually in July or holds a special meeting.

"[That] flurry of orders did just come out last week, and we are still looking into them and evaluating potential implications," he said. "I can commit to you that once our team has gone through them and developed an approach for how we might want to engage with any elected officials or otherwise and we need to inform the SPC of what our plans and intentions are or get feedback from you, we will schedule some time.

"We understand the SPC's role in these types of activities."

He said members should direct any feedback or specific requests to Kevin Bryant, the RTO's first executive vice president of stakeholder affairs and chief strategy officer, who goes by "KB." Bryant's team is coordinating the executive order review and will facilitate the committee's future conversations on the EOs.

SPC Scope Changes Add Members

The SPC endorsed revisions to its scope that include increasing its membership from 14 to as many as 29, matching the Members Committee's sector representation. The MC participates in board meetings and provides advisory votes to the directors.

The sectors will select their representatives to fill the 14 vacant seats, following SPP's normal processes. The board also can add one of its members to the SPC. The Corporate Governance Committee and the board will review and approve the selections. Current members will not be affected.

Kelley said the scope changes reflect SPC's new focus on ensuring that "we're staying on the forefront of the pace of change that is happening with our industry and certainly, the things that are affecting SPP," as determined by members' feedback.

The CGC also will consider the changes and make a recommendation to the board. The directors will select the nominees in August.

The nominations have been submitted, but two sectors (the Independent Power Producer/Marketer and the State Power Agency) have more candidates than open seats and will have to settle on their final slate.

SPP Releases FERNS Report

A planned presentation and discussion of Brattle Group's Future Energy & Resource Needs Study (FERNS) was rescheduled for the July SPC meeting, but *the report* itself already has been published.

Among its findings, the report predicts renewable generation will grow "significantly," even without federal tax credits or other clean energy policies. Brattle said because of renewable energy's abundant availability in the SPP footprint and declining technology costs, carbon-free generation's share could reach about 90% by 2050. It predicts the RTO will serve growing loads "reliably and affordably" through a combination of fossil-fueled generation, wind, solar, nuclear, hydro and battery storage resources.

Engineering Vice President Casey Cathey said the study was aggressive in 2023 and that SPP already has surpassed the study assumptions.

SPC members also approved transitioning the Future Grid Strategy Advisory Group to the Grid Transformation Advisory Group, advising and reporting to the SPC. It will continue as an advisory group, reporting directly to the SPC, and collaborate with other groups and staff while focusing on developing ideas that bring long-term strategic advantage.

Mike Skelly Lunches with SPC

Renewable energy entrepreneur Mike Skelly, escorted by board member Stuart Solomon, crashed the SPC's pre-meeting lunch. He then looked on as the meeting began.

"I heard there was a lunch here," he explained to an SPP stakeholder inquiring about his presence.

Skelly attended the Gulf Coast Power Association's spring conference in the morning before making the seven-block trek to the SPC's hotel.

"How could you tell? Was it because of this?" he said to *RTO Insider*, flipping his brightly colored tie.

Skelly grew Horizon Wind Energy, now part of EDP Renewables North America, and founded Clean Line Energy. Clean Line went under in 2017 in the face of legal, political and bureaucratic obstacles. Skelly since has co-founded *Grid United*, where he is the CEO. ■

FERC Approves SPP's Funding Plans for Markets+

Commission Dismisses PIO Concerns Around BPA's Commitments

By Henrik Nilsson and Robert Mullin

Why This Matters

SPP's funding plans for Markets+ prompted some controversy in the Northwest about how the Bonneville Power Administration fits into the equation, but FERC rejected those concerns in its order approving the funding agreement.

DENVER — FERC, in two separate orders, approved SPP's $150 million funding agreement for Markets+ and the funding mechanisms under which the RTO will finance the implementation phase of the market's development.

News of the decision met with an enthusiastic response at a meeting of the Markets+ Participants Executive Committee (MPEC) in Denver.

"I have some lovely breaking news. FERC has approved the funding agreement, the funding mechanism today," Carrie Simpson, SPP vice president of markets, said at the meeting, prompting applause among committee members.

"These achievements represent meaningful steps in the progress towards launching Markets+ and bringing the West closer to realizing the substantial value of a robust regional market," SPP COO Antoine Lucas said in an April 22 press release. "SPP is proud to see the hard work of the Markets+ stakeholders pay off in this series of approvals that clear the path toward market launch in 2027."

Specifically, FERC approved the SPP Phase 2 funding agreement, which lays out how SPP will finance Markets+'s $150 million in implementation costs (*ER25-1372*).

Eight Western entities have already signed the agreement as of April 16: Arizona Public Service, Bonneville Power Administration, Chelan County Public Utility District (PUD), City of Tacoma, Grant County PUD, Powerex, Salt River Project and Tucson Electric Power.

The agreement requires the entities to provide collateral to SPP's lender to support the financing the RTO will use to develop Markets+ during the implementation phase. The collateral is equal to the amount of the entities' Phase 2 obligations.

The recovery of the costs to repay the implementation financing "will be incorporated into the rates charged in the Markets+," according to a frequently asked questions document posted on SPP's website.

"This eliminates the need for the funding participants that participate in Markets+ to provide lump sums of money to directly fund Phase 2 outside of the specific circumstances outlined in the funding agreement (i.e., withdrawal, termination, default)," according to the FAQ.

A significant detail in the funding agreement order: FERC's rejection of concerns raised by a group of public interest organizations (PIOs) around the Bonneville Power Administration's connection to the agreement.

The PIOs protested that the agreement would effectively obligate BPA to participating in Markets+ even ahead of issuing its formal record of decision (ROD) on its day-ahead market participation because the agency would be on the hook for providing up to $40 million in implementation costs to SPP even before releasing the ROD. They contended that either SPP's filing had mischaracterized BPA's commitment to Markets+ or that the agency had been engaging in a "sham" process regarding its day-ahead market decision.

"We disagree with PIOs that the funding agreement requires Bonneville (or any other funding participants) to participate in Markets+," FERC wrote. "As PIOs acknowledge, the funding agreement requires a funding participant to pay its Phase 2 obligations in the event it decides to withdraw from the funding agreement; however, the funding agreement does not obligate any funding participant to proceed with Markets+ participation."

The commission also dismissed the PIOs' concerns around how a funding participant such as BPA would cover its costs if it decided to withdraw from the market, saying the issue was out of scope for the order.

"In addition, because the funding agreement does not govern whether or how a withdrawing funding participant will recover its Phase 2 obligations after a withdrawal, we find PIOs' arguments about Bonneville's plan to recover such potential costs are outside the scope of this filing.

"We also find that PIOs' arguments concerning Bonneville's decision-making process related to Markets+ participation, including any associated communications with stakeholders, are outside the scope of the filing," the commission wrote.

Funding Mechanism

The second order concerned SPP's funding mechanism, which details how the RTO "will finance the implementation phase of the market's development," according to SPP's news release (*ES25-33*).

The mechanism will entail SPP taking out a $150 million loan collateralized by the full funding obligation of each Markets+ participant, except BPA.

The commission approved the mechanism despite its failure to meet FERC's interest ratio coverage screen, a measure of how readily an entity can cover its debt.

"SPP has cited other factors that provide the commission with a sufficient alternative basis upon which to conclude that SPP has reasonable prospects for being able to service the proposed new debt securities for which authorization is sought in the application, and to continue to be able to provide service as a public utility," the commission wrote. ■

— Tom Kleckner contributed to this article.

Xcel 'Optimistic' It Will Handle Tariffs, Trade War

By Tom Kleckner

Xcel Energy CEO Bob Frenzel tried to reassure the investment community during the company's first-quarter earnings call that Xcel is better prepared for the trade war that may or may not be coming and the tariffs — and not the ones utilities are accustomed to — that already have arrived.

"The sentiment meter has definitely changed over the last 45 days, but I don't think we've seen a lot of change in actual activity yet, either," Frenzel told financial analysts during the April 24 call. "What you see here in this earnings season from a lot of people, whether it's banks or industrial manufacturers … is a thoughtfulness around capital right now."

Frenzel said Xcel is "cautiously optimistic" it will work through the months ahead as it manages more than $10 billion in its incremental investment pipeline. He said the company has taken steps to diversify its vendors and materials, noting its $45 billion base capital plan has about a 2 to 3% exposure to tariffs.

CFO Brian Van Abel said Xcel has been talking with its large oil and gas customers in the Permian Basin, where prices have been teetering at the point where the economics don't make sense to drill. He said they are watching tariffs and their effects on companies.

"But so far, we haven't seen that impact on us," Van Abel said. "One month doesn't make a trend."

Xcel *reported* first-quarter earnings of $483 million ($0.84/share), compared to $488 million ($0.88/share) for the same quarter a year ago. The change was driven by higher operations and maintenance expenses and depreciation and interest charges, partly offset by increased recovery of infrastructure investments.

The Minneapolis-based company's earnings failed to meet the Zacks consensus estimate of $0.96/share.

Frenzel made it clear that Xcel expects clean energy to be part of its fuel mix going forward. He said management sees a need for batteries and other energy storage assets, with a "relatively rapid evolution" of the battery supply chain similar to what it has seen with solar panels the past few years. At the same time, the company has been retiring a coal plant a year, he said.

Xcel also has engaged with the Trump administration and federal lawmakers about the executive orders and tariff actions and the need for policies that allow cost-effective and rapid adoption of new energy resources, Franzel said. The key is preserving "tech-neutral tax credits" for wind, solar, storage and nuclear and the credits' associated transferability provisions in various loan and grant programs.

"Xcel Energy anticipates that we will need to deliver between [15,000] and 29,000 MW of new generation by year-end 2031," he said.

Still, Frenzel said Xcel "remains confident" in its ability to meet its earnings guidance for the 21st year in a row. "One of the best track records in the industry," Franzel mused.

Xcel's share price closed the week on April 25 at $69. It has declined $2.55 a share since the April 23 close, a drop of 3.6%. ■

Why This Matters

The CEO's remarks reflected recognition of investor anxiety over President Trump's trade policies.

| Xcel Energy

NextEra Energy Continues to Rack up Renewables Deals

CEO Says Gas, Coal and Nuclear Cannot Meet Expected Demand

By John Cropley

Solar and gas-burning generation facilities owned by Florida Power and Light are shown in Parrish, Fla. | *NextEra Energy Resources*

NextEra Energy posted solid *first-quarter financials* and said its renewables portfolio continued to grow even as President Donald Trump began implementing pro-fossil fuel policies.

CEO John Ketchum said during an April 23 conference call that wind, solar and storage are indispensable now as the U.S. expects to need a lot more megawatts because renewables can be brought online much faster than natural gas generation and much, much faster than nuclear.

He called renewables "a critical bridge" to a future when other technologies can be brought online at scale.

Until fairly recently, many people were calling natural gas the "bridge fuel" to a decarbonized future. But natural gas has problems, said Ketchum, whose company is an all-of-the-above energy provider operating renewable, nuclear and natural gas generation.

The cost to build a gas plant has tripled in just a few years, and Trump's tariffs will drive the cost higher, he said. Meanwhile, companies building LNG export terminals, factories and data centers have lured away the skilled workers who would build gas plants, and gas turbine manufacturers are booked up with yearslong wait times on new units.

"Gas is such a long-term solution," Ketchum told analysts on the conference call. "We've gone up from four and a half years to build a combined cycle unit to six or longer."

This state of affairs, he said, calls for energy realism — understanding the high demand and embracing all solutions — and calls for energy pragmatism — recognizing that some solutions are not ready today and accepting the tradeoffs this implies.

Why This Matters

A leader in the renewables sector remains bullish even as federal policies move to sideline renewables.

"Renewables and battery storage are the lowest-cost form of power generation and capacity," Ketchum said, "and we can build these projects and get new electrons on the grid in 12 to 18 months."

The U.S. is expected to need more than 450 GW of new generation by 2030, he said, and only 75 GW of that is expected to be natural gas fired. Canceling every planned coal retirement would yield only about 40 GW more. Meaningful increases in nuclear generation are 10 years away at best and likely to be much more expensive than gas when they arrive, he added.

In this scenario, NextEra expects to thrive, despite renewables suddenly falling into presidential disfavor.

In the first quarter, subsidiary NextEra Energy Resources originated 3.2 GW of new renewables and storage and scored its largest-ever quarter for solar and solar-plus-storage origination, bringing its project backlog to 28 GW.

Meanwhile, subsidiary Florida Power & Light placed 894 MW of new solar generation into service, bringing its owned-and-operated solar portfolio to more than 7.9 GW — the most of any U.S. utility.

"We continue to see a lot of appetite for renewables," Ketchum said.

And what of the actual and threatened tariffs that are causing such consternation in so many sectors of the economy? NextEra began to get ready for this years ago. Because it is so large and its competitors are mostly small, it had the leverage and buying power to shift tariff risks onto suppliers in most of its contracts, Ketchum said. NextEra forecasts only $150 million in tariff exposure through 2028 on $75 billion in projected capital expenditures, he said, and may be able to negotiate that exposure down as low as $0.

It also shifted to U.S.-made components, where possible.

"We didn't just wake up on Nov. 6 and say, 'Oh my God, what do we do about our supply chain?'" Ketchum said. "We've been thinking about this for years, and so we put the right things in place."

NextEra reported first-quarter revenue of $6.25 billion, up from $5.73 billion a year earlier, and GAAP net income of $833 million ($0.40/share), down from $2.27 billion ($1.10/share).

Adjusted (non-GAAP) earnings were $2.04 billion ($0.99/share), up from $1.87 billion ($0.91/share). ■

Company Briefs

Tesla Earnings Down in Q1

Tesla last week reported $13.97 billion in automotive revenue for the first quarter of 2025, marking a drop of nearly 20% from the same quarter last year, according to its earnings release.

Tesla's overall revenue — including automotive, energy generation and storage, and other services — came in at $19.3 billion for the quarter, decreasing 9% compared to last year. For quarterly net income, Tesla reported $409 million — down 71%.

More: *Fox Business*

Austin Energy GM Kahn Retiring

Bob Kahn, who has served as general manager of Austin Energy for nearly two years, will retire at the end of June, but he will leave his post April 30.

Prior to his current position, Kahn served as general manager of the Texas Municipal Power Agency and as CEO of ERCOT.

City Manager T.C. Broadnax said Stuart Reilly will serve as interim general manager starting May 1.

More: *Austin Monitor*

Hitachi Energy to Expand in Va.

Hitachi Energy last week said it will invest $22.5 million to expand its electrical transformer facility in Bland County, Va., while adding another warehouse in Smyth County.

Hitachi Energy currently produces medium-voltage transformers at the Bland County facility. The 77,000-square-foot warehouse was home to a ZF TRW Automotive facility until it closed in 2022 and will be used for core cutting, which is the process of cutting steel sheets and other materials used in the transformer's core.

More: *Cardinal News*

Federal Briefs

U.S. Aims for 3,500% Tariffs on Solar Panels from Southeast Asia

U.S. trade officials finalized steep tariff levels on most solar cells from Southeast Asia, a key step toward wrapping up a year-old trade case in which American manufacturers accused Chinese companies of flooding the market with unfairly cheap goods.

A petitioner group, the American Alliance for Solar Manufacturing Trade Committee, accused big Chinese solar panel makers of shipping panels priced below their cost of production and of receiving unfair subsidies that make American goods uncompetitive. The tariffs unveiled last week vary widely depending on the company and country but are broadly higher than the preliminary duties announced late last year.

For the tariffs to be finalized, the International Trade Commission must vote in June on whether the industry was materially harmed by the dumped and subsidized imports.

More: *CNN*

EPA to Lay off 300 More Workers

In a notice issued to employees last week, EPA said 280 staffers who work in the Office of Environmental Justice and External Civil Rights in Washington or who do that work in regional offices would be laid off at the end of July.

An additional 175 employees who "perform statutory functions or support the agency's core mission were reassigned to other offices," an agency spokesperson said. The notices follow the agency's decision in February to place nearly 170 employees in the office on administrative leave.

In February, the administration said it plans to cut the agency's spending by 65%.

More: *Inside Climate News*

BLM Restarts Solar, Storage Permitting

The Bureau of Land Management has resumed its review of solar, storage and geothermal applications, a spokesperson said last week. Wind approvals remain frozen pending further review of permitting practices.

Following President Donald Trump's return to office, the Department of the Interior suspended all authorizations of renewable energy on federal land for 60 days, including leases and rights of way.

More: *Reuters*

State Briefs

ARIZONA

Gov. Hobbs Vetoes Bill to Waive SMR Regulations

Gov. Katie Hobbs vetoed a measure that would have waived certain regulations to allow data centers and other large industrial energy users to build small nuclear reactors.

Hobbs said the bill "put the cart before the horse by providing broad exemptions for a technology that has yet to be commercially operationalized anywhere in this nation."

The bill would have let large industrial energy users build an SMR in their facility without having a certificate of environmental compatibility and would have made them exempt from local zoning restrictions.

More: *AZ Mirror*

MICHIGAN

Alpena Power Looks to Skip Outage Bill Credits After 'Act of God' Storm

Alpena Power is looking to dodge a requirement it issue $40 bill credits to customers who went days without power following an ice storm in March.

The utility argues the storm that snapped hundreds of thousands of acres of tree branches and cast the region into darkness was an "act of God" causing widespread blackouts it could not possibly have avoided. Automatic outage credits could total between $1 million and $1.5 million, the utility estimated in a filing with regulators.

Alpena is requesting the Public Service Commission issue a temporary waiver giving it a pass from the outage credit rules.

More: *MLive*

DTE Energy Seeks 11% Rate Increase

DTE Energy last week submitted a request with the Public Service Commission for a $574 million rate increase.

DTE said the funds are needed to recover costs to improve grid reliability, switch to cleaner energy sources and maintain reliability during the transition.

The increase, which would take effect Feb. 24, 2026, would raise average residential bills by 11.1% and commercial customers' rates by 10.8%. Industrial customers' rates would increase 5.4%.

More: *The Detroit News*

Proposal Aims to Stop Political Spending by DTE, Consumers

A bipartisan group of House lawmakers, backed by a coalition of activist groups, last week announced a four-bill package that would ban political contributions by DTE Energy and Consumers Energy, along with other corporations seeking large government contracts.

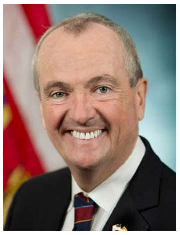
In the last election year with disclosures available, 2022, a Consumers-funded nonprofit called "Citizens for Energizing Michigan's Economy" reported spending nearly $4.6 million. Michigan Energy First, a nonprofit linked to DTE, spent close to $4.9 million in the same year. The bills would prohibit the utilities from giving to those types of nonprofit accounts as well as similar 527 organizations.

Lawmakers introduced similar legislation in 2024, but the bills never received a hearing.

More: *Bridge Michigan*

NEW JERSEY

Gov. Murphy Signs Legislation to Prevent Utility Bill 'Sticker Shock'



Gov. **Phil Murphy** last week signed a bill that will require utilities to inform certain customers of their energy use and costs before monthly bills are issued.

The bill is intended to allow customers to adjust energy usage to avoid unforeseen spikes in costs. Customers will be notified on the 10th and 20th days of a billing cycle.

More: *New Jersey Monitor*

NEW YORK

Con Edison Plans Start of New Tx Line in Queens

Con Edison last week said construction will start this winter on a new transmission line in Long Island City, Queens.

The $125 million, 200-MW Reliable Clean City-LIC project will connect the Vernon and Newtown substations.

The line should be in service by the summer of 2026.

More: *Daily Energy Insider*

NORTH DAKOTA

PSC Approves High-voltage Tx Line

The Public Service Commission last week approved siting for a $360 million, 162-mile high-voltage power line project by Basin Electric Power Cooperative.

The 345-kV line, which is expected to be completed by October 2026, will run through multiple counties.

More: *KFGO*

OREGON

Senate Passes Bill that Blocks Passing Wildfire Costs to Customers

The state Senate last week voted 22-6 to pass a bill that would prevent utilities from passing wildfire-related damages onto customers if a court finds the company liable for the fire.

Under the bill, such companies would not be able to recoup costs tied to court judgments, legal fees, settlements or repairs by increasing consumers' electricity rates. Also, any utility that owes unpaid damages from a wildfire-related court ruling would be banned from issuing dividends, repurchasing stock or distributing profits to its investors.

The bill now moves to the House.

More: *KATU*

RHODE ISLAND

Judge Rejects Chevron's Motion to Dismiss Climate Change Lawsuit

Rhode Island Associate Justice William Carnes last week rejected all arguments made by Chevron in its attempt to dismiss a climate change lawsuit.

Chevron was one of 21 oil and gas companies sued for its role in exacerbating climate change in a state climate change lawsuit brought by then-Attorney General Peter Kilmartin in 2018. The complaint seeks damages from fossil fuel companies on the assertion that for each company, "a substantial portion of fossil fuel products are or have been extracted, refined, transported, traded, distributed, marketed, promoted, manufactured, sold and/or consumed in Rhode Island." After years of appeals, concluding after the U.S. Supreme Court declined to take up the case in April 2023, Chevron returned to state court seeking to have a portion of the case thrown out.

Carnes concluded there was no evidence of improper actions by the state — at least, not enough to meet the "high bar" of imposing penalties for Rule 11 violations.

More: *Rhode Island Current*