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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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RTO Insider
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CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

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Tri Bui

Sales Development Representative
Nicole Hopson

RTO Insider LLC
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885

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In this week's issue

FERC/Federal News

FERC Order 1920 Sees Wide-ranging Rehearing Requests

By James Downing

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FERC has received rehearing requests on Order 1920 ranging from stakeholders who just want to see a few tweaks, to those who prefer the commission trash the entire order and start over.

Many states filed for rehearing on the order, arguing for more authority and flexibility for their efforts to reform transmission planning and cost allocation rules that started before FERC issued its order. (See *Order 1920 Rehearing Request from States Seek Bigger Role in Tx Planning*.)

The only two RTOs that filed for rehearing also sought flexibility to keep going with the changes they have been working on with stakeholders. PJM seeks to continue with its Long-Term Regional Transmission Planning (LTRTP) process and SPP with its Consolidated Planning Process (CPP).

PJM's changes would lead to a process where, working with states and other stakeholders, it could come up with scenarios based on evolving concerns such as the changing resource mix and new demand. It was designed to reflect the realities of the RTO's region, which is "comprised of 14 jurisdictions that have public policy initiatives that are simultaneously overlapping and conflicting — while also taking into consideration the challenges the PJM region is facing as a result of the accelerating energy transition."

The LTRTP process is meant to deal chiefly with reliability while considering states' policy requirements in consultation with them. The rule prevents transmission providers from setting up cost allocation methods that separate out reliability, economic and public policies, but PJM said its disparate state membership means it should be exempted from that. The LTRTP process does not align with Order 1920's requirements perfectly, and some details differ from FERC's requirements, the RTO said.

"However, PJM believes that the PJM LTRTP process is directionally consistent with the commission's long-term planning goals, and importantly, the process recognizes PJM's unique needs and circumstances," the RTO said.

SPP asked for clarification that it could move forward with a different set of rules around its CPP process.

"The CPP will include a comprehensive long-term assessment that projects supply and demand needs over a 20-year period, incorporating regional and subregional components," the RTO said. "The CPP will allow for simultaneous planning of transmission, as opposed to the piecemeal approach SPP employs today."

The new planning process uses a single, common base model for the entire region, it improves data collection, and SPP said it was working on a cost allocation method that would require flexibility from some of Order 1920's requirements.

The Re-evaluation Requirement

One area transmission owners singled out for review was the requirement that transmission projects be re-evaluated after they're picked in a regional plan under Order 1920.

It kicks in when projects are delayed long enough to impact reliability, if actual costs significantly exceed estimates, or if some underlying law or policy changes.

The Edison Electric Institute argued that section of the rule was poorly noticed, with FERC pointing to paragraph 248 in the Notice of Proposed Rulemaking. The utility trade group argued that paragraph lacked sufficient detail to count as appropriate notice under the Administrative Procedure Act.

"The onus is on the agency to inform stakeholders that it is considering a proposal put forth in comments; the onus is not on stakeholders to sift through thousands of pages of comments and respond to each one in case the agency should decide to use a particular proposal as the basis for its final rule," EEI said.

FERC/Federal News

Order 1920 largely takes MISO's transmission planning process and sets it as the baseline for other regions to implement their own rules around, but a large group of MISO TOs argued that the re-evaluation requirement goes well beyond what they are used to in one key way: The RTO's "variance analysis" does not require transmission lines to be re-evaluated using new benefits that have been updated since it initially was planned.

The benefit re-evaluation requirement conflicts directly "with the commission's intended goal of shaping a regulatory environment that facilitates regional transmission development," the MISO TOs said.

Using new benefits in the updated process creates massive uncertainty for transmission development and basically "requires re-planning every five years," they added. That increases the risk that transmission will be removed from the plan based on entirely new inputs and assumptions, which can put at risk permits required by other regulators and could implicate projects already under construction.

"Such uncertainty also risks spooking investment in these crucially needed transmission facilities and may delay subsequent portfolios of long-term regional transmission facilities as the resources that would otherwise be used in their development will be used to re-evaluate past portfolios," the TOs said.

The WIRES Group also told FERC it should reconsider the re-evaluation requirement because it could undermine, by delay or cancellation, the development and timely completion of long-term regional transmission facilities.

Rights of First Refusal

Both WIRES and EEI had the re-imposition of rights of first refusal as a major goal for the order, and FERC did that with projects "right-sized" from the local planning process into the regional planning process, but neither of them brought up the issue in their rehearing filings.

The right-sized ROFR did come under fire from the Electricity Transmission Competition Coalition, the Resale Power Group of Iowa and LS Power Grid.

"Competition in the transmission planning process for the right to develop and construct new transmission facilities reduces costs to consumers and drives efficiencies in project construction," ETCC said. "The Competition Coalition supports competition and competitive prices to maintain just and reasonable transmission rates, consistent with Order No. 1000's pro-competition directives."

Giving incumbent owners a ROFR over transmission projects elevated out of the local planning process was meant to deal with what FERC said were infirmities in those processes. But the rule change is not based on any finding that the current regional planning processes are unjust and unreasonable.

"Nevertheless, in its declaration that [Federal Power Act] Section 206 allows it to act, Order No. 1920 seems to take the position" that it can modify any tariff provision regardless of whether it was found to be is just and reasonable, ETCC said. "There is no statutory or judicial support for such a broad reading of the requirement under the first prong of Section 206 of the Federal Power Act."

Environmentalists Want Stronger Requirements

A joint filing from "public interest organizations" — including the Environmental Defense Fund, the Environmental Law & Policy Center, the Natural Resources Defense Council, the Sierra Club and the Sustainable FERC project — said they support the general direction of the order and FERC's goal to efficiently expand the grid.

Order 1920's changes "represent the lynchpin of the commission's multi-proceeding reform effort," and they "applaud the commission's extensive stakeholder engagement and thoughtful consideration of the nearly 17,000 pages of comments from nearly 200 diverse parties," the environmentalists said.

But the commission should issue firmer mandates to get around the "inherent economic incentives of transmission providers (and their generation owners)" that lead them to avoid building out transmission to preserve local market power, they argued. FERC should specifically require that transmission planners must plan around access to cheaper generation and cannot discount that benefit.

Clean Energy Trade Groups Request Tweaks

Advanced Energy United, the American Clean Power Association, American Council on Renewable Energy and Solar Energy Industries Association — filing as the "Clean Energy Associations" — supported most of the order, but they filed a request seeking a handful of changes.

The commission was wrong to include interconnection-related upgrades in the short-term process and the new 20-year LTRTP process envisioned in Order 1920, they said. The commission also should change the order by eliminating a requirement that those network upgrades meet minimum voltage thresholds, as its rationale was ambiguous on how transmission providers must determine network upgrades for inclusion in the regional plans, they argued.

The rationale for leaving network upgrades in the short-term plans that still will be run under the Order 1000 process is that they need to be built soon under generators' interconnection timelines.

"However, the Clean Energy Associations respectfully submit that near-term progress and long-term progress in this area are not mutually exclusive and should be pursued in parallel," they argued.

Harvard Electricity Law Initiative Backs State Cost Allocation Rights

FERC decided against requiring transmission providers to file state agreements on cost allocation because of the precedent set when Atlantic City Electric sued it over related issues.

But Harvard Law School's Electricity Law Initiative argued that case applies only to utility filing rights under FPA Section 205. FERC still could make it a requirement under Section 206; not doing that effectively expands *Atlantic City*'s legal impact.

"*Atlantic City* does not prevent the commission from amending the *pro forma* OATT to include a process for filing all regional cost allocation methods approved by relevant state entities, regardless of the transmission provider's approval," the Harvard group said. "Imposing a process for filing relevant state entities' cost allocation methods would not 'deny [utilities] their right to unilaterally file rate and term changes.'"

The new process would supplement the existing cost allocation processes, whether held by TOs or RTOs. Giving states a guarantee that their work will be given at least a review by the commission would be a marked improvement over what the rule contemplates: states gathering to come up with ideas that the RTO or utilities can reject to use their own cost allocation method instead.

"State regulators might prefer to forgo this process entirely in order to avoid bargaining in the shadow of transmission providers' veto authority," the Harvard initiative said. "By placing transmission providers above state officials, the final rule grants utilities leverage over their regulators, potentially interfering with regulators' duties under state law." ■

Study Claims Powerex Backing Markets+ to Benefit from Divided West

By Robert Mullin

A new study commissioned by Renewable Northwest (RNW) adds a contentious new wrinkle to the debate about the potential impact of market seams if the West ends up divided between CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+.

The *study*, conducted by Grid Strategies, comes about five months after release of a report from the Western Power Trading Forum and Public Generating Pool that cautioned that seams between Western day-ahead markets would create a different set of challenges from those seen at the boundaries between the full RTOs in the Eastern Interconnection. (See *Western Market Seams Issues to Differ from East, Study Finds*.)

The Grid Strategies study partly expands on that theme, finding that effective "market configuration" — meaning a market based on the widest footprint possible — outweighs the importance of market design. It also warns that lessons from the Eastern Interconnection show that market seams there continue to be a "persistent drag on efficiency" despite the mechanisms MISO, PJM and SPP have implemented to mitigate their impact.

The study also delves into the specific challenges a two-market scenario could pose in the Pacific Northwest, where neighboring and closely interconnected balancing authority areas — such as those operated by the Bonneville Power Administration and PacifiCorp — fall into separate markets, creating a winding and complicated boundary.

BPA, which controls about 75% of transmission in the Northwest, has made it clear its decision on a day-ahead market will not be driven by concerns about seams and has argued such issues can be resolved by seams agreements. (See *Seams Concerns Won't Drive Day-ahead Market Decision, BPA Says*.)

The Grid Strategies study finds that "while experience in other markets support BPA's argument that a seams agreement is necessary, experience also shows that seams agreements do not reduce barriers to transacting across market seams and will not address the detrimental impact of market seams on consumers."

'Hard to Achieve'

But the most controversial aspect of the new study is the contention that Vancouver, British Columbia-based energy marketer Powerex has backed the development of Markets+ because it stands to make more money trading in a divided West than in a single market with no seams.

That's an assertion other Western electricity sector stakeholders have shared with *RTO Insider* but have been reluctant to put on the record.

"Well, to the detriment of my dreams to retire in Canada, I decided to go on the record," RNW Executive Director Nicole Hughes joked in an email to *RTO Insider*. RNW is a renewable energy trade group that long has advocated for the development of a single organized market in the West and is a key supporter of CAISO's EDAM.

Hughes was referring to a June 14 opinion piece she wrote for the Seattle-based publication *Clearing Up*.

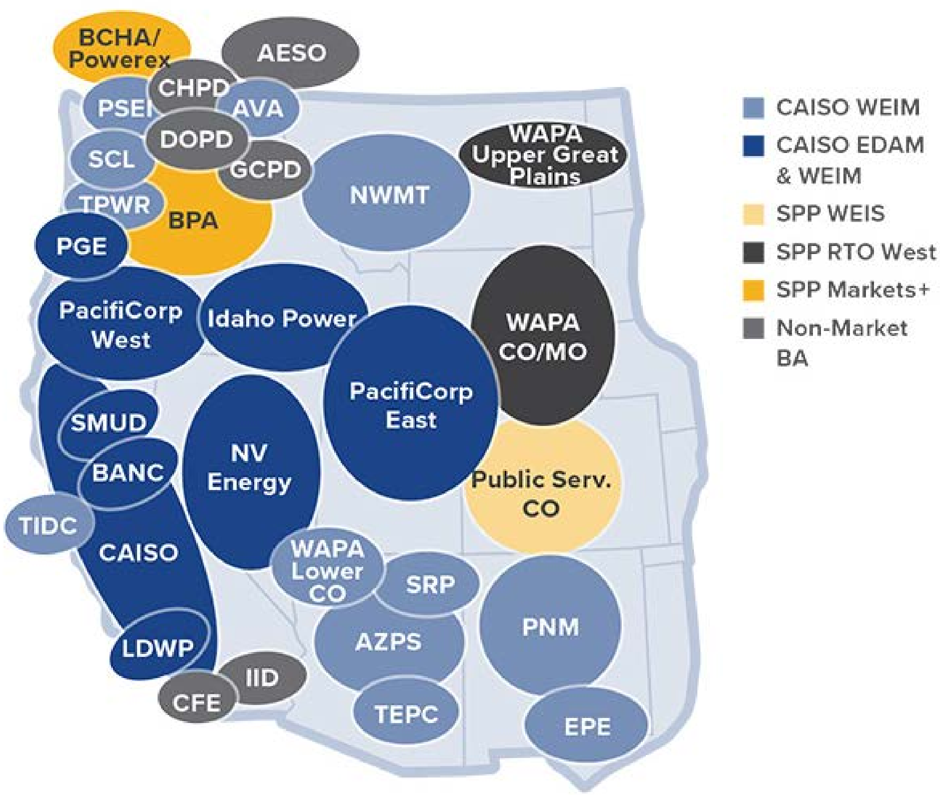
The *op-ed* draws on Chapter 9 of the Grid Strategies study, which is headed "Good Configuration is Hard to Achieve Because Some Parties Benefit from Bad Configuration and Inefficient Seams."

The chapter explains that BPA and Powerex control the largest amount of power supply and transmission in the Pacific Northwest, the latter being "the exclusive marketer of BC Hydro capability in the U.S., holding substantial hydro generation, storage and transmission rights, and is a major energy supplier to the Northwest."

Powerex's "mission" in participating in the U.S. market is "to maximize profits" on behalf of British Columbia's ratepayers, the study says.

"As the exclusive marketer for BC Hydro, Powerex reports that electricity 'trade provides economic and environmental benefits for British Columbia. All income generated by Powerex is returned to BC Hydro, which helps the utility keep electricity rates amongst the lowest in North America,'" it says, citing Powerex's description of itself in the "*About Us*" section of its corporate website.

Last year, the Western Markets Exploratory Group (WMEG) completed a series of studies, conducted by Energy+Environmental Economics (E3), to assess the benefits that would accrue to various electricity market participants in the West under a range of market footprint scenarios.



Current day-ahead market "leanings" of balancing authorities across the West | *Renewable Northwest*

Grid Strategies cites wording in the WMEG study for Powerex, which found that in a scenario where Northwest utilities join EDAM, Powerex "expects that its most attractive market opportunities would be forward sales," prompting the company to limit the hourly flexibility of its hydroelectric exports.

But in a situation where Northwest utilities join Markets+, E3 determined Powerex "expects that its most attractive market opportunities will be hourly optimized transactions" and that it would offer the market its full hourly flexibility.

"E3 estimates that the incremental regionwide cost increase attributable to Powerex's withholding hourly flexibility in these scenarios is approximately $7 million," Grid Strategies says. "This example shows how positional power and control of transmission can have significant financial consequences for consumers in the Northwest."

As the competition between EDAM and Markets+ plays out, SPP has found its strongest support among some entities in the Northwest, including BPA and Powerex, and among Arizona utilities Arizona Public Service, Salt River Project and Tucson Electric Power. But other major players in the Northwest, including PacifiCorp, Portland General Electric and Idaho Power, have signaled their intent to join EDAM, with Seattle City Light likely to follow.

Transmission links between the Northwest and Southwest are limited, and the Grid Strategies study notes that "control of key transmission capacity rights connecting the Northwest to the Southwest is highly concentrated, with a meaningful portion controlled by Powerex, who as a power marketer has an objective of maximizing profits, rather than minimizing consumer costs as do load-serving transmission capacity owners."

"A pivotal supplier exercising market power can manipulate prices, benefiting itself to the detriment of load-serving entities and consumers," the study continues. "It is very difficult to mitigate this market power in a two-market setting with no centralized oversight of the broader region. If the seams were more efficiently managed internally within a single market, this would be less likely to occur."

Powerex Points to Governance, Design

In her op-ed, Hughes points out Powerex controls about 20% of transmission capacity rights on the California-Oregon Intertie, a key link between the Northwest and CAISO. She says direct trade with the Desert Southwest would allow Powerex to avoid paying to wheel power through the CAISO system.

"Powerex states that the solution to congestion rents wheeling through CAISO is to build more transmission to the Desert Southwest," Hughes wrote. "More interregional transmission connectivity between the two regions would definitely benefit customers Westwide. However, several utilities serving major load centers are committed to continuing to operate in CAISO's WEIM [Western Energy Imbalance Market] and have committed to expanding their commitment by joining its Extended Day-Ahead Market, while BPA is leaning toward leaving the WEIM and joining Markets+."

Hughes also asserts the WMEG study indicates BPA would benefit from increased transmission revenues in a divided day-ahead market scenario while the rest of the region would see rising transmission costs.

Reached for comment, BPA spokesperson Doug Johnson said the federal power marketing administration was unprepared to respond to the Grid Strategies study or Hughes' op-ed.

In an email to *RTO Insider*, Jeff Spires, director of power at Powerex, said that while "attention to seams is important," the intent of the study "appears to be to distract from the essential governance and market design elements that differentiate the two day-ahead market options."

"Powerex is just one of numerous entities participating in the development of Markets+, who collectively seek an organized market that provides independent and inclusive governance, an impartial market operator and a market design that achieves competitive market outcomes while balancing the interests of a broad array of participants," Spires wrote.

Takeaways

The Grid Strategies study concludes with a handful of "key takeaways." Chief among them is the assumption FERC is "unlikely to mandate good configuration and does not have a template for effective, efficient and equitable seams coordination," leaving it to Western utilities and regulators "to evaluate customer impacts and make the best decisions for ratepayers" when it comes to day-ahead market decisions.

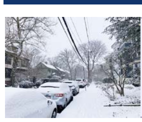
Another point is that attempts to address market inefficiencies caused by seams in the East have been "largely unsuccessful."

"Transactions between markets are far below efficient levels, resulting in higher consumer costs," the study says.

Yet another takeaway has to do with the access issues that would stem from a two-market configuration in the Northwest because of the region's "heavy reliance" on BPA's transmission.

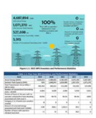
"If market seams are developed between the major load centers in the region and the generation and transmission needed to serve these load centers, costs to consumers will increase, and efforts to bring new clean energy generation to load will be hindered," the report says. "Particular attention should be paid to avoiding development of these seams today, and ample opportunity currently exists to develop a market [that] will minimize negative impacts to customers." ■

National/Federal news from our other channels



FERC Preparing Multiple NERC Decisions

ERO Insider



NERC State of Reliability Report Notes Progress, Challenges in 2023

ERO Insider

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CAISO/West News

CAISO Kicks off Stakeholder Process for Pathways Initiative

WWGPI Launches Committee and Stakeholders Discuss Step 1, Governance Shift

By Ayla Burnett

CAISO on June 18 kicked off the West-Wide Governance Pathways Initiative stakeholder process required to shift the ISO's governance structure to an independent entity within the Extended Day-Ahead Market (EDAM).

During a conference call, members of the initiative's Launch Committee presented Step 1 of the "stepwise" approach, which would elevate the "joint" authority over both the EDAM and the Western Energy Imbalance Market that the latter's Governing Body shares with CAISO's Board of Governors to "primary" authority. This means the body would be the first to vote on tariff change proposals for both markets.

The moves are meant to quell fears about the ISO's state-run governance structure. (See *Pathways Initiative to Act Fast on 'Stepwise' Governance Plan*.) California's governor appoints members of the ISO's board, on which the State Senate votes to confirm.

The stepwise approach was outlined in a *straw proposal* released June 5.

"We're looking to create a structure that can enable the largest footprint possible and include California," said Kathleen Staks, WWGPI co-chair and director of Western Freedom.

"We ultimately want this entity to be able to evolve and add market services up to and including a full regional transmission organization."

The first round of stakeholder feedback led Launch Committee members to highlight a focus on respecting state and local authority in the initiative, "ensuring we are creating a structure that respects each individual state's ability to set and enforce its own energy policies," Staks said. "We are not looking to create something that is going to enable one state to force its policies on another state and vice versa."

Over the summer, committee members and stakeholders will be working on a proposal for Step 2, which would establish a "regional organization" as a legal entity and, after passage of required California legislation, transfer the Governing Body's primary authority to "sole" authority.

Stakeholder Comments

Some stakeholders expressed concern that the initiative still doesn't achieve the level of independence needed to quell concerns surrounding CAISO's governance structure.

"We appreciate steps forward with the Step 1 proposal to extend [Federal Power Act Section] 205 filing rights and primary authority to the WEIM Governing Body," said Doug Marker, intergovernmental affairs specialist at Bonneville Power Administration. "But at the same time, as we've said, we don't believe that it by itself achieved the level of independence from any one state's authority that's necessary for a regional market.

"What we're concerned about is that transition to primary authority could lead to the CAISO Board of Governors being disconnected from WEIM and EDAM issues and possibly increased conflict between the Board of Governors and the WEIM Governing Body."

Marker requested that the committee consider elements that could be added to the proposal that could support continued collaboration between both entities.

"We have a number of [Governance Review Committee] members … who are aware of the perceived and, I think, real value of the increased collaboration that happened moving to the joint authority model," responded Spencer Gray, committee members and executive director of the Northwest & Intermountain Power Producers Coalition. "While we didn't touch on the mechanics of whether the two bodies would continue to be jointly going forward, we certainly didn't want to preclude that approach."

A second stakeholder call is tentatively set for July 23. ■

CAISO officially kicked off the stakeholder process for the West-Wide Governance Pathways Initiative. | *CAISO*

CAISO/West News

PUCN Sets Framework for NV Energy's EDAM Participation

Nev. Regulator Describes How Utility Should Seek Membership in CAISO Day-ahead Market

By Elaine Goodman

As NV Energy moves forward with plans to join CAISO's Extended Day-Ahead Market, Nevada regulators have laid out a framework for how the company can seek approval for EDAM participation.

NV Energy should make the request through an amendment to the company's energy supply plan, according to an order the Public Utilities Commission of Nevada (PUCN) approved June 21. NV Energy used a similar process in 2014 to get PUCN approval for joining CAISO's Western Energy Imbalance Market (WEIM).

And as part of its request, NV Energy should address a long list of questions posed by the PUCN, ranging from the costs to join a day-ahead market to how participation will impact revenues and rates and what a path to an RTO would look like.

A Nevada law adopted in 2021 requires transmission providers in the state to join an RTO by January 2030.

The PUCN opened a docket in October 2023 to explore regional market activities in the Western Interconnection.

Commissioner Tammy Cordova, the presiding officer in the case, held three workshops this year on day-ahead market participation and invited two rounds of stakeholder comments. The workshops looked at cost-benefit studies and market design for the two competing Western day-ahead markets: CAISO's EDAM and SPP's Markets+.

Meanwhile, NV Energy recently stated its intent to join EDAM and provided some of the rationale for its decision in its 2025/27 integrated resource plan filed May 31. (See *NV Energy Confirms Intent to Join CAISO's EDAM* and *Market Footprint Critical for EDAM Decision, NV Energy Says*.)

The company expects to file a request to join EDAM this year.

The announcement came after a Brattle Group study this year projected that NV Energy's benefits under EDAM would range from $62 million to $149 million in 2032, depending on the market footprint, whereas Markets+ benefits would range from a $17 million loss to a $16 million gain.

During the commission's June 21 meeting, Cordova said the cost-benefit analyses are just one factor to consider in a day-ahead market choice.

NV Energy headquarters in Las Vegas | *Moonwater Capital*

"It was really important to me that we had information beyond just production-cost modeling when we would evaluate whether or not any request by NV Energy was in the public interest," Cordova said.

In a request to join a day-ahead market, the commission wants to hear about the market's governance and who else plans to join.

Other questions focus on the resiliency of the market to natural disasters or cybersecurity threats. PUCN wants to know how GHG emissions will be tracked and the impact on compliance with the state's renewable portfolio standard.

Another issue is the impacts on non-jurisdictional transmission customers in NV Energy's balancing authority area.

Other questions are the impact of joining a day-ahead market on generation development and on building new transmission.

In written comments, PUCN staff said NV Energy should be required to address "whether the potential $5 [billion] to $10 billion of transmission investments proposed for Nevada will be impacted depending on which [day-ahead market] NV Energy requests to join."

Staff pointed specifically to the Cross-Tie, SWIP-North, One Nevada No. 2 and TransWest projects.

In comments filed May 30, NV Energy expressed support for the list of questions.

"Examination of these areas will provide a comprehensive assessment of the potential benefits associated with DAM participation in general and of specifically joining the EDAM," the company said.

Following approval of its order June 21, the commission is largely wrapping up the day-ahead market portion of the docket.

But in a second phase of the docket, the PUCN will be taking a closer look at RTO participation. A schedule for the RTO phase of the docket has yet to be established.

"This docket is by no means done," Cordova said. ■

CAISO/West News

Stakeholders Call on CAISO to Take Larger Role in Reliability Planning

ISO Should Conduct LOLE Modeling 'Calibrated for Climate Change,' WPTF Recommends

By Ayla Burnett

CAISO stakeholders are calling on the ISO to take a bigger role in reliability planning because of the increasingly complicated nature of ensuring reliability on the California grid in the face of climate change.

"At this point in time, we have arguably five different agencies involved in keeping the lights on in California," Carrie Bentley, CEO of Gridwell Consulting, said on behalf of the Western Power Trading Forum (WPTF) during a June 18 presentation to the ISO's Resource Adequacy and Program Design Working Group.

Key among those other agencies are California's Public Utilities Commission, Energy Commission and Department of Water Resources, which manages the state's strategic energy reserve.

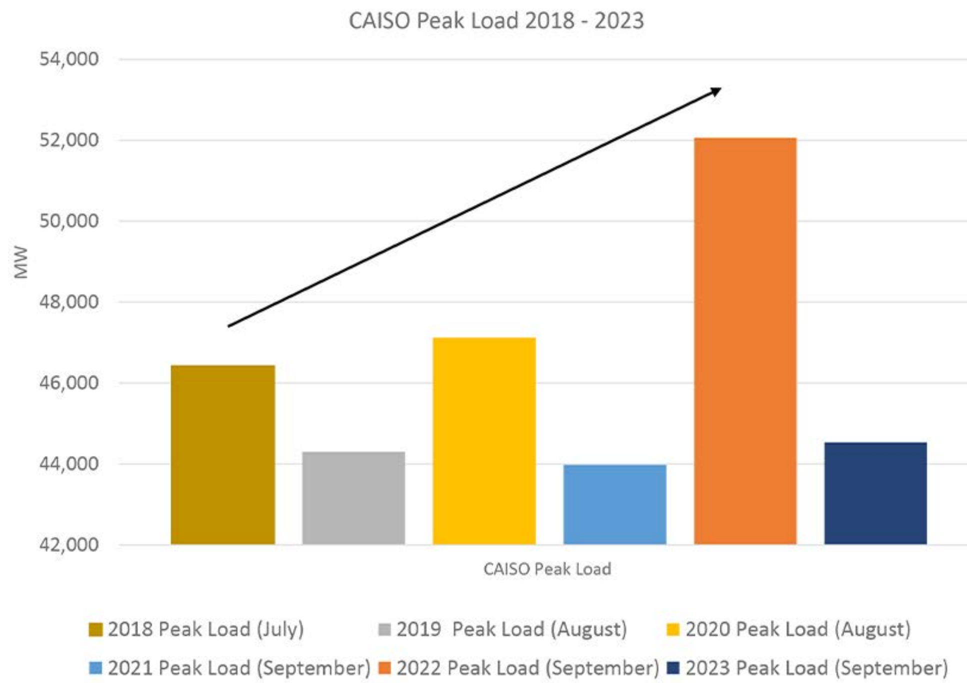
"We have overlapping processes that are only getting more complex over time. The coordination and processes are growing more complex because the state is not only trying to accommodate climate change, [and] plan for climate change, but it's also trying to prevent climate change," Bentley said.

Because no single agency is in charge of ensuring "holistic" reliability, Bentley proposed that CAISO take on that role and, more specifically, conduct probabilistic loss-of-load-expectation (LOLE) modeling to better understand the aggregate impact of the changing climate on grid conditions.

"This [LOLE modeling] actually allows you to say, 'What are the impacts of all of these probabilities, all these different extreme events, and these different levers being pulled on by different agencies? What is the aggregate impact on the CAISO balancing area?' And the only way I know to do that robustly is through loss-of-load-expectation modeling," Bentley said.

In addition to driving up peak load, higher temperatures are also causing "astronomical" increases in load variability, Bentley said. Between 2017 and 2023, that variability was significant enough to cause load forecasts to deviate from actual loads by several thousand more megawatts than historically normal.

Planning processes must account for increases in variability to ensure reliability, Bentley said. And because resource planning is conducted over so many different agencies and processes, it is unclear if processes are "calibrated for climate change" or if "CAISO's balancing area is actually reliable," she added.



"Astronomical" peak load increases coupled with changing climate and grid conditions have made reliability planning more challenging. | *Western Power Trading Forum*

"There is a clear and present need for not just re-evaluation of individual processes for climate change, but also to do this holistically. And we think CAISO is uniquely suited to provide this function. In fact, we think CAISO is probably the only agency that will be able to provide this function because they're the only ones with a clear picture," Bentley said.

Bentley also called on CAISO to update counting rules and the planning reserve margin (PRM).

Other stakeholders expressed support for Bentley's suggestions.

"This resonates incredibly … and is something we deeply need," Cathleen Colbert, senior director of Western markets and policy at Vistra, said during the meeting. "We need to understand, what is the reliability status of the balancing authority area on a forward-looking probabilistic basis?"

Aditya Jayam Prabhakar, director of resource assessment and planning at CAISO, reassured stakeholders that the ISO is already working to address Bentley's two main requests: to evaluate forward CAISO reliability assessments in terms of LOLE modeling, and to update default PRM and RA counting rules.

WPTF also requested that the ISO establish a comprehensive mothball and retirement process for generating plants based on local needs, but Bentley emphasized that the LOLE modeling should first be "stood up, and then it will naturally flow into other processes." ■

ERCOT News

ERCOT Board Chair Foster Steps Down

By Tom Kleckner

Paul Foster, who chaired ERCOT's first Board of Directors under rules established in the aftermath of 2021's disastrous winter storm, announced June 18 that he is stepping down from the position.

Vice Chair Bill Flores will replace Foster on an interim basis, effective June 20.

Foster said he had been thinking about leaving when his term expired this year. However, he said a recent discussion with Texas Gov. Greg Abbott (R), who plays a role in selecting ERCOT's board members, hastened his decision.

"It became clear to me it'd be much more beneficial to the board and to ERCOT for this transition to happen sooner rather than later," Foster told the board. "ERCOT has a tremendous amount of work to do in the last half of 2024 leading into a legislative session. ... The board has a lot of work to do, shaping and supporting these efforts. Having a new board chair and a new board member in place as soon as possible and well in advance of the legislative session is what would be best for ERCOT."

The Texas Legislature meets biennially. Its 90th session begins next January, with legislators expected to probe ERCOT's market changes and performance.

Foster was appointed as chair in October 2021 as one of the revamped board's first two independent directors. The previous board's members, six of whom did not live in Texas, resigned under pressure after Winter Storm Uri brought the grid within minutes of a total collapse. (See *Two New ERCOT Directors Named, Replacing Current Board*.)

Legislation passed after the storm now requires board members to be Texans and independent of the ERCOT market, and have executive-level experience in several disciplines. A three-person board-selection committee appointed by the governor and the state's other two political leaders is responsible for picking board members.

Foster is president of Franklin Mountain Investment and founder of Western Refining. An El Paso philanthropist, he has been *renovating a third downtown building* in his hometown.

"When I took this job, I had only a very high-level understanding of the grid and the market," Foster said. "What I've come to learn in my tenure as chair is that this is the most dynamic, innovative, adaptive and forward-looking electric grid and competitive market in the world. Texas and ERCOT are at the forefront in the global energy transfer transformation that is currently taking place ... and frankly, I think we're handling it better than just about anybody else."

Foster heaped praise on ERCOT's staff and the Public Utility Commission, which oversees the grid operator.

"As I leave this post, I truly believe that ERCOT is headed in the right direction with the right people in leadership and poised to lead the world through the energy transformation that we're in the middle of," he said. ■

Paul Foster visits with a board member before his first board meeting. | *© RTO Insider LLC*

ERCOT News

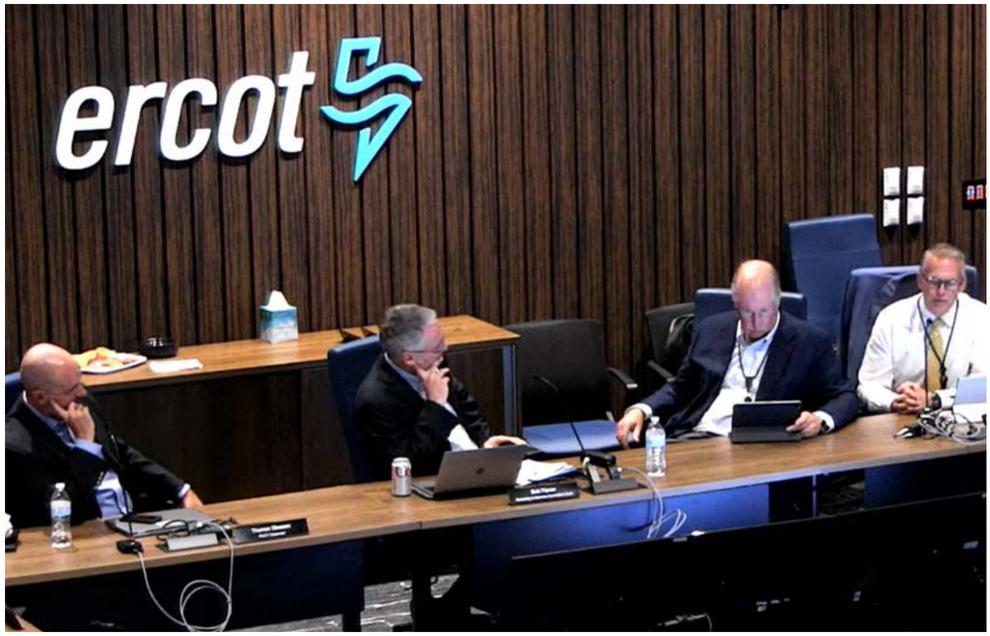
ERCO Board of Directors Briefs

Contentious NPRR Revising ECRS Passes over Monitor's Objections

ERCOT's Board of Directors took up two contentious protocol changes during its June 18 meeting that have divided staff and stakeholders, tabling one it had previously remanded and approving the other over objections from consumer interests and the Independent Market Monitor.

Potomac Economics President David Patton made his second appearance in less than six months before board members to press his case against the grid operator's heavy use of ERCOT contingency reserve service (ECRS).

Patton, whose firm holds ERCOT's IMM contract, said he was "very disappointed" with the board's approval of the protocol change (*NPRR1224*). The rule change sets a price floor of $750/MWh for the product, which procures capacity resources that can be brought online within 10 minutes and sustained at a specified level for two consecutive hours.



ERCOT CEO Pablo Vegas (right) explains ECRS' value to (left to right) PUC Chair Thomas Gleeson and Directors Bob Flexon and John Swainson. | *ERCOT*

"This is the first time I've seen [a grid operator] advocate for such a proposal that is designed to undermine the competitive performance of its market — reducing reliability to artificially inflate its real-time prices," Patton told *RTO Insider*.

The Monitor last year said the ECRS product, ERCOT's first new ancillary service in 20 years, created artificial supply shortages that produced "massive" inefficient market costs totaling about $12 billion during the year. The service was first deployed in June. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

"I think this is one of the most important votes to approve something that you'll ever take," Patton told the board's Reliability and Markets Committee on June 17. "The key objectives of any competitive, deregulated wholesale markets is that they produce efficient and competitive outcomes that maintain the reliability. NPR1224 violates all three of those objectives."

In his *presentation* to the committee, Patton said NPRR1224 will effectively have ERCOT administer a withholding framework where key economic units are physically withheld from the real-time market until they are deployed. He said it economically withholds the resources after deployment by attaching the $750 offer floor, "for which there is no competitive basis."

Because ERCOT doesn't yet co-optimize energy and ancillary services in real time (that is scheduled to come online in 2026), ECRS is quarantined from the real-time market. The Monitor projects that if conditions this year are similar to 2023's, the NPRR will generate "inefficient and anticompetitive" costs exceeding $5.7 billion. Patton recommended staff instead develop procedures that would anticipate a security-constrained economic dispatch (SCED) shortage and then deploy ECRS.

Attorney Katie Coleman, who represents Texas Industrial Energy Consumers, advocated for a $100 price floor but supported 1224 as an interim step before real-time co-optimization (RTC) is added to the market.

"We are concerned that with the $750 price floor, we are not making much progress relative to last summer's experience," she said. "We do support a stopgap between now and real-time co-optimization to insulate the market from those effects, but we believe that the $100 floor is the appropriate level."

ERCOT staff said they had drafted another protocol change (*NPRR1232*) as a follow-up to NPRR1224. It would introduce a mechanism to make some ECRS available to SCED every hour, assuming the latter NPRR's price floor is codified into the protocols. Staff said the price floor represents the opportunity cost of depleting available reserves for use in the real-time market.

Staff said ECRS has been deployed 52 times through May 2024, with 43 of those occasions providing frequency recovery or to cover net load ramps. ERCOT CEO Pablo Vegas used that data point in supporting NPRR1224, which he said is intended to provide some benefits during the summer.

NPPR1224 "represents an improvement over what we saw last year in terms of lowering the price," Vegas said. "The [Technical Advisory Committee] has worked together to try to find a pathway that addresses some of the cost implications that we saw last summer. It preserves the unique characteristics of ECRS and what we're able to do under manual deployments today with our control room. It represents the first step in a series of ... steps that are going to track us towards RTC.

"I would recommend we move forward with the work that TAC has done and take this first step to see the benefit this summer. We'll be able to take continued lessons learned into 1232 as we set up the automation of the release of ECRS. We're going to have to get comfortable as a committee and as a board dealing with issues where there are strong pros and strong cons. We're not going to be able to necessarily find the middle ground that makes everybody happy on these kinds of issues."

The R&M Committee, divided over the

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deliberative stakeholder process and a lack of transparency into the price floor, voted 3-1 to approve NPRR1224. The Office of Public Utility Counsel's CEO, Courtney Hjaltman, cast the dissenting vote over concerns the price floor is too high. She abstained from the full board's unanimous vote.

NOGRR245 Bifurcated, Delayed

The board also agreed with staff's *recommendation* to table a revision to the Nodal Operating Guide (*NOGRR245*) that has been bandied back and forth between stakeholders and staff since late last year. The proposed rule change would impose voltage ride-through requirements on inverter-based resources.

Staff said tabling the measure will give them additional time to hammer out an agreement with some stakeholders by bifurcating or decoupling parts of the exemptions and extension process for legacy assets unable to meet ride-through requirements.

"ERCOT believes one more opportunity to work with joint commenters is appropriate to potentially give regulatory certainty," staff said.

General Counsel Chad Seely said ERCOT will work to schedule a special board meeting before the regular Aug. 19-20 bimonthly meetings to take up NOGRR245's exemptions and extension process issues. He said that will allow staff to quickly hand off the measure to the Texas Public Utility Commission for policy discussions. The measure's reliability assessment process and criteria for hardware upgrades necessary to meet its requirements will go through the normal stakeholder process, with a December target to go before the board.

"This is a critical reliability issue for the grid. It's time to move this forward and hand this off to the commission as expeditiously as possible," Seely said, expressing optimism that staff will be able to "effectively bifurcate" the issue.

TAC endorsed the rule change June 7 after several months of trading and reviewing comments with ERCOT, gaining staff's support in the process. The committee inserted gray-box language with potential modifications that wouldn't become effective until March 2025. The language was aimed at those entities for which upgrade costs are less than 40% of the full, in-kind replacement cost of a plant's inverters or turbines and converters. (See *ERCOT TAC Endorses Rule for Inverter-based Resources*.)

However, the joint commenters — primarily renewable developers — protested the change and threatened to file a complaint at the PUC, saying TAC attempted to defer issues around hardware changes by placing them in the gray-box language. They urged the board to ensure that the ride-through standards "do not have the unintended consequences of harming reliability by eliminating existing generation and harming future investment in infrastructure in the ERCOT market." (See *Renewable Developers Oppose Proposed ERCOT IBR Rule*.)

Chad Seely, ERCOT | *ERCOT*

The NOGRR is meant to align the grid operator's protocols with NERC reliability guidelines and the most relevant parts of the Institute of Electrical and Electronics Engineers' standard for IBRs interconnecting with the grid. The board in April remanded the NOGRR back to TAC, directing that the language be modified to address ERCOT's reliability concerns.

ECRS Slows Energy Prices' Drop

ERCOT IMM Director Jeff McDonald said that while he wasn't going to focus on ECRS in briefing the board, the ancillary service had a profound effect on the market last year.

"I know it comes up repeatedly in the report ... but you will see it is the focus in certain areas in the report because it had a fairly profound effect on energy prices and overall cost," he said in sharing the Monitor's annual *State of the Market report*.

McDonald said the load-weighted average energy prices were down about 13% to roughly $65/MWh in 2023 from the year before, even though natural gas prices declined more than 60% during the same period. The report attributes that difference to the "adverse" effects of ECRS' implementation, noting that real-time prices drive those in the day-ahead and forward markets.

"Electricity prices will be correlated with natural gas prices in a well-functioning market because fuel costs represent the majority of most suppliers' marginal production costs, and natural gas units are generally on the margin in ERCOT," the report says.

ECRS' effect on real-time prices was largely confined to the hotter months of June through September, McDonald said. "So, it did roughly double the real-time energy price during that period."

McDonald said the IMM spent a "fair amount" of time looking at the market's competitiveness, finding it to be competitive with little evidence that suppliers exercised market power. He said that while the market has provided sufficient revenues to signal the need for more generation in four of the past six years, he was unable to explain why it took the subsidization of gas plants' construction through the Texas Energy Fund to make that more of a reality. (See *Vistra Joins Rush for Dispatchable Generation Loans*.)

"As a project developer, you need to see a series of revenues in the market that would support your investment before you undertake it," he theorized. "In the investment world, policy risk is a big factor, especially for large capital ... investments. So I'll be spending more time trying to find a satisfactory answers to your question."

ERCOT: Another Hot Summer

Dan Woodfin, ERCOT's vice president of system operations, told the board that staff meteorologists expect this summer to be among the hottest on record, as have the past few summers.

"Probably not as hot as last summer, where we just had lots and lots of hot temperatures," he said. "We've actually had quite a few of the summers within the last few years that have been well above normal, and so we expect this summer to fit in with that. Given what we've seen in June, I think that we're trending that way."

"We're seeing a pretty significant little bit higher growth during the summer period than what we've seen in some of the other seasons," CEO Vegas said. "It's a little bit higher than what we've seen across other seasons over that same period, and it's likely due to the very hot summers recently that we've just had. So we've seen some very recent high weather that has helped to boost some of the demand growth."

According to a recent University of California, Berkeley *study*, the state's average temperature has risen by about 2.7 degrees Fahrenheit

ERCOT News

since the dawn of the industrial age. However, the heat index has been as many as 11 degrees higher during that same period.

The past two summers have been the second- and third-hottest on record, and four of the 10 hottest summers have come in the past six years, Vegas said. September 2023 was the hottest September on record and included ERCOT's first energy emergency since the disastrous February 2021 winter storm.

ERCOT set a new demand market record last August of 85.5 GW during a summer in which it issued 17 weather watches, voluntary conservation notices or conservations appeals. As of June 20, it was *projecting* more than 80 GW of demand on June 26, marking the first 80-GW day of the season. The June record for peak demand came last year at 80.8 GW.

"We are prepared for this summer," Vegas said, citing weatherization inspections, "meaningful" growth in generation resources and tabletop exercises.

2nd DR RFP Canceled

Vegas said ERCOT is canceling a request for four-hour demand response after it received three offers with less than 10 MW.

A request for 3,000 MW of six-hour DR last fall was canceled when the grid operator received 11.1 MW of potential eligible capacity.

"It is clear from the two recent experiences with capacity [requests for proposals] ... that we need to modify the approach for developing the next set of demand response capabilities in the ERCOT market," Vegas said, echoing similar comments he made last year. (See *ERCOT Cancels RFP for Additional Winter Capacity*.)

He added that he is confident there is "significant potential" in both residential and commercial and industrial demand response classes. "We need to take a more in-depth approach working with market participants to develop a demand response product that will be additive to the reliability capabilities at an ERCOT market level," Vegas said.

ERCOT staff are working with PUC staff on a study Vegas said "shows meaningful potential for incremental demand response." Texas A&M University is nearing completion of the study in advance of next year's Texas legislative session, PUC Commissioner Kathleen Jackson said.

"Our stretch goal is that we want to look at the lay of the land and come up with recommendations that hopefully we can bring forth during the next legislative session," Jackson said.

Board Approves $1.12B Project

The board approved ERCOT's recommended $1.12 billion project to rebuild 345-kV infrastructure in West Texas that will address thermal overloads and petroleum production load-growth issues in the region. The project was also unanimously endorsed by TAC.

Oncor, the transmission provider, will disconnect existing 345- and 138-kV transmission lines before rebuilding about 245 miles of new line and switches. It will also build a new substation and upgrade terminal equipment. The utility plans to complete the work by summer 2028.

The board's consent agenda included seven NPPRs, two NOGRRs and three revisions to the Planning Guide (PGRRs):

- *NPRR1198*, *NOGRR258* and *PGRR113*: add an extended action plan as a constraint-management plan suitable to managing congestion resolvable by SCED.
- *NPRR1212* and *PGRR114*: clarify a distribution service provider's obligation to provide an electronic service identifier for a resource site that consumes load other than wholesale storage and is not behind a non-opt-in entity tie meter.
- *NPRR1218*: updates the state's renewable energy credit trading program to clarify that it only applies to solar renewable energy.
- *NPRR1220*: modifies the market's restart process to require board and TAC approval and provide an alternative mechanism to board approval under certain circumstances.
- *NPRR1222*: elevates final approval of the "*ERCOT Methodologies for Determining Minimum Ancillary Service Requirements*" other binding document from the board to the PUC, consistent with commission discussions.
- *NPRR1223*: updates a protocol form to require transmission and/or distribution service providers to provide contact information to ERCOT.
- *NPRR1228*: decreases the number of firm fuel supply service obligation periods awarded in a procurement from two to one.
- *NOGRR255*: establishes high-resolution data requirements.
- *PGRR112*: sets requirements for interconnecting entities to submit dynamic data models and for transmission service providers to submit final full interconnection studies for approval at least 30 business days before the quarterly stability assessment deadline. ■

— Tom Kleckner

IMM's David Patton argue against ECRS' use. | *ERCOT*

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ISO-NE News

FERC Accepts Results of New England Capacity Auction

By Jon Lamson

| © RTO Insider LLC

FERC accepted the results of ISO-NE's Forward Capacity Auction 18 on June 18, finding that the auction was run according to the RTO's tariff and that protests submitted by climate activists were outside the scope of the proceeding (*ER24-1290*).

FCA 18, which was held in February and relates to the 2027/28 capacity commitment period (CCP), saw an approximately 40% increase in the cost of capacity relative to the previous auction, along with a rise in renewable resources. (See *Prices, Renewables Rise in New England Capacity Auction*.)

The auction likely marks the last auction held prior to the implementation of major changes to ISO-NE's capacity market.

The RTO is amid a multiyear process reworking how it calculates resource capacity values, and also is pursuing significant changes that would split the annual CCP into seasons and hold auctions much closer to each CCP. This year, FERC approved a three-year delay of the next capacity auction to give ISO-NE time to develop these changes with the goal of implementing them for FCA 19. (See *FERC Approves Additional Delay of ISO-NE FCA 19*.)

ISO-NE's filing of the results spurred opposition from climate activists, who argued the auction was biased in favor of fossil fuel resources. (See *Climate Activists Urge FERC to Reject Results of ISO-NE FCA 18*.)

"These results are in violation of ISO-NE's tariff and mandate to 'protect the health of the region's economy and the well-being of its people by ensuring the constant availability of competitively priced wholesale electricity — today and for future generations,'" the group No Coal No Gas wrote in comments signed by more than 4,000 individuals. The group also protested the results of the three prior FCAs.

"FCA 18's award of nearly $350 million in forward capacity payments to fossil fuel peaker plants is a clear violation of this mission," the organization added. "Supporting fossil fuel generators that can only provide electricity by worsening climate change and exacerbating grid instability is dangerous, irresponsible grid management."

Echoing its response to the protests of previous FCAs, FERC sided with ISO-NE, ruling that the structural critiques of the auction are outside the scope of the proceeding. (See *FERC Accepts Results of ISO-NE FCA 17*.)

The commission wrote that the protests "do not bear on the sole question here — namely, whether ISO-NE conducted FCA 18 in accordance with the requirements set forth in its tariff."

"Instead, these protests largely challenge the FCM design and raise various challenges related to climate change, fossil fuels, the minimum offer price rule and the Merrimack Generating Station, which are issues that are beyond the scope of the instant proceeding," FERC said.

FERC added that the concerns about a conflict between ISO-NE's mission statement and the capacity market design "are more appropriately raised in the stakeholder process."

ISO-NE applauded FERC's ruling, writing in a statement that "the Forward Capacity Market is and has been open to all resources able to provide capacity to the region, and claims of bias are without merit."

"All the new resources clearing in this year's auction were renewable energy, battery storage or demand-reducing resources," wrote ISO-NE spokesperson Matt Kakley. "We look forward to continuing to work with stakeholders and the New England states on longer-term changes to the capacity market."

Meanwhile, climate activists expressed disappointment with the decision and took issue with the commission's suggestion that they raise their concerns within the NEPOOL stakeholder process.

Marla Marcum of No Coal No Gas emphasized that the NEPOOL process is closed to nonmembers and that member groups representing end users have minimal voting power within the organization.

"Referring us to a body to which we are unlikely to gain access, and which explicitly limits public input and agency, is unfortunately typical of this system — a system designed to prevent meaningful participation," Marcum said, adding that FERC's ruling suggests ratepayers "should have no effective way to participate in decisions about the billions of dollars taken from their utility bills every year to manage the grid." ■

ISO-NE News

ISO-NE PAC Briefs

ISO-NE *announced* its plans to increase the transfer limits of three interfaces in Maine at the Planning Advisory Committee's meeting June 20.

The RTO is planning to up the limits of the Orrington-South interface from 1,325 MW to 1,650 MW, the Surowiec-South interface from 1,500 to 1,800 MW and the Maine-New Hampshire interface from 1,900 to 2,000 MW.

Dan Schwarting of ISO-NE said the new limits will be incorporated into day-to-day operations, including the wholesale energy markets, in late June or July.

"Impacts on capacity transfer limits, and any resulting implications for Forward Capacity Market-related activities, will be discussed in future meetings," Schwarting said, adding that the new limits will also apply to future planning efforts.

Asset-condition Projects

New England transmission owners discussed proposals for several major new investments to address degrading transmission infrastructure.

Zach Logan of Avangrid *presented* a proposal by Maine Electric Power Co. to replace aging poles on a 345-kV transmission line in the eastern part of the state. While the company has determined "the overall condition of the lines are good to fair, and there are no immediate needs for a complete line rebuild," most of the poles date back to 1969 and are expected to deteriorate at an increasing rate as they pass 60 years of age.

The company is proposing to replace structures at a rate of about 40 to 50 per year through 2038, at a total estimated cost of $344 million.

Chris Soderman of Eversource Energy *presented* a follow-up to the company's *February presentation* of a proposed rebuild of a 115-kV line in New Hampshire, projected to cost about $361 million with an in-service date in the fourth quarter of 2026.

Responding to stakeholder feedback submitted after the February presentation, Eversource analyzed the costs of a partial line rebuild compared to the full rebuild that is currently planned. The company found that partly rebuilding the line would save money in the near term but ultimately increase overall project costs to about $437 million when accounting for subsequent projects that would be needed to replace other aging structures.

"The bulk of these structures are already 40 years old" and need to be replaced "in a relatively short time frame," Soderman said.

Soderman also *presented* a proposed $5.5 million project to replace 19 structures on a 115-kV line between Maine and New Hampshire, projected to be complete by the end of the year.

John Babu of Eversource *announced* a $5 million project to replace eight relays on a 115-kV substation in Harwinton, Conn. Eversource said the manufacturers are no longer producing replacement parts for the relays. ■

— Jon Lamson

Pole deterioration on Eversource's X-178 Line in New Hampshire | *Eversource*

MISO News

MISO's 2nd Long-range Tx Portfolio Jumps to About $25B

By Amanda Durish Cook

MISO's second, mostly 765-kV long-range transmission plan could tip past $25 billion with the addition of more projects, stakeholders have learned.

RTO staff said its "near-final" second long-range transmission plan (LRTP) stands between $23 billion and $27 billion, up from the original range of $17 billion to $23 billion. The grid operator plans to submit the portfolio to its Board of Directors for approval in early December.

"That is currently where we'll think we will land, including underbuilds," Director of Economic and Policy Planning Christina Drake said of the cost during a teleconference June 21. The proposed portfolio will require "underbuilding," or secondary, lower-voltage transmission upgrades to support a 765-kV network in the Midwest region. MISO is still finalizing its list of underbuild projects. It also has yet to translate its reliability and economic analyses into a business case for the second LRTP portfolio.

MISO last month said it would add seven 765- or 345-kV projects in the Dakotas, Minnesota, Michigan, Indiana and Iowa and replace an original 765-kV project in Missouri and Iowa with segments of 345-kV line in the St. Louis metropolitan area. (See "MISO Undeterred, Plans More LRTP Projects," *MISO IMM Knocks LRTP Benefit Calculations; RTO Poised to Add More Projects*.)

"We're in some of the final stages here of economic and reliability robustness testing," Drake said.

MISO's analyses so far indicate that with the second, expanded portfolio, its Midwest region reduces curtailments by 8.5% annually — or by 20.4 million MWh — by 2042. Reductions in curtailments should assist fleet evolution, the RTO said. They should also reduce adjusted production costs by allowing the dispatch of the most economical units.

RTO staff said the portfolio would allow more generation dispatch from its West region to flow east to population centers. MISO's analyses showed the portfolio "enables and incentivizes" energy deliveries from renewable sources in Minnesota, the Dakotas and Wisconsin, which will cut down on price separation in the Midwest region.

MISO said it expects LRTP II to overall reduce the cost to serve load in the Midwest by the early 2040s. While the Central region could save $2.20/MWh and the East region $.70/MWh, costs could rise at times in the West region, which will export more often.

The RTO also said the portfolio would reduce congestion to improve existing transmission limits, especially in its Central and East planning regions.

Some stakeholders said the savings seemed underwhelming for the scale of the proposed 765-kV network.

MISO Senior Expansion Planning Engineer James Slegers cautioned stakeholders that when more generators can deliver output, the greater volumes will likely aggravate congestion on other flowgates. The RTO said it plans to address congestion shifts through the underbuild process or through its next LRTP portfolio.

The RTO is planning to debut a second part of the portfolio that proposes more projects for MISO Midwest.

Drake said MISO is aware that the $25 billion portfolio would not enable all new deliveries of generation the RTO expects in the next 20 years.

"That's why we're taking this in two slices," Drake said. She said the second part will be considered a separate portfolio and able to stand on its own merits.

WEC Energy Group's Chris Plante challenged MISO's characterization of the second LRTP being a standalone portfolio. He likened the system to a car that needs major repairs in addition to several secondary issues.

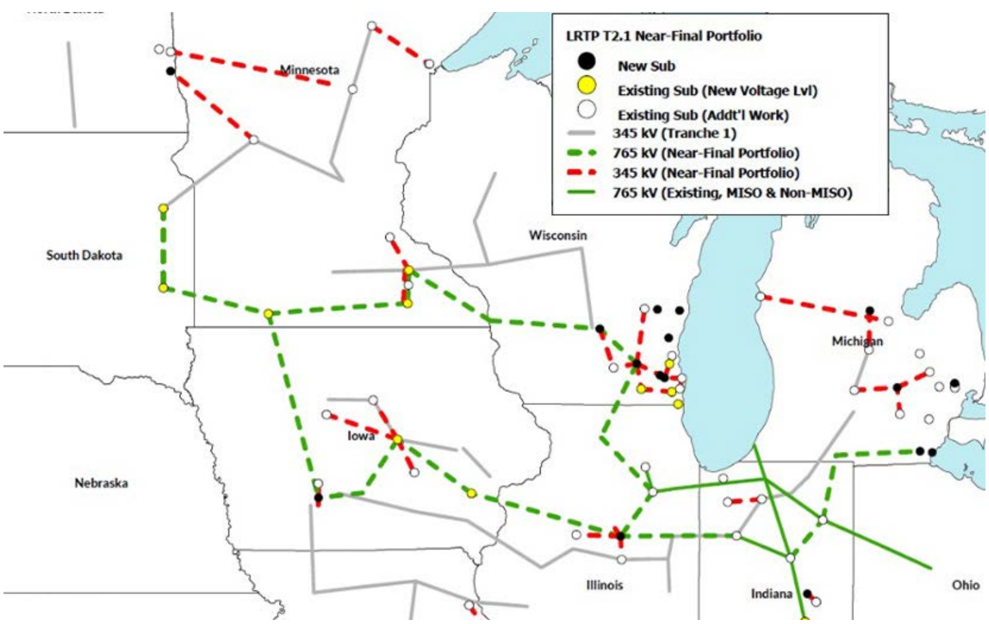
"We need to look at all the problems of the vehicle. I appreciate MISO saying that it's standalone, but that's a red herring. Just say what it is: It doesn't address all of the constraints. Let's be honest," Plante said.

MISO Executive Director of Transmission Planning Laura Rauch said that despite not proposing to solve all system issues with this portfolio, MISO is nonetheless demonstrating that it provides value and sustains reliability.

Drake said that without the second LRTP, curtailments, overloads and price separation will proliferate, and new resources will be prevented from connecting to an already strapped system.

The LRTP portfolio would resolve most impending thermal violations on 200-kV and above facilities in the Midwest, MISO said. But for facilities under 200 kV, it said, the second LRTP appears to solve thermal violations less consistently. Staff said some of the remaining violations are better addressed through MISO's routine annual transmission planning or through network upgrades assigned to generators trying to complete the interconnection queue.

MISO will host another LRTP workshop July 17. ■



The network of 765- and 345-kV lines that MISO anticipates recommending to its board in December | *MISO*

MISO News

MISO Readies JTIQ Filings, Hints at More Tx Portfolios with SPP

By Amanda Durish Cook

Two years after announcing its $1.8 billion Joint Targeted Interconnection Queue (JTIQ) transmission portfolio with SPP, MISO is putting final touches on its FERC filings to make it happen.

During a June 18 teleconference to outline its plan, MISO's Milica Geissler said the RTO will begin making filings to FERC at the end of July, starting with an addition that chronicles JTIQ procedure for its joint operating agreement with SPP. Subsequent filings on cost allocation, generator interconnection agreements and rate schedules will follow, Geissler said, and may be standalone or combined. All filings concerning JTIQ will seek a common effective date, she added.

MISO said it will work with its transmission owners to make the later filings. SPP similarly is finalizing JTIQ details. (See *SPP Board Adds Final OK to JTIQ Cost Framework*.)

"We've been working on this for four years, and we're finally able to present a full package," MISO Director of Resource Utilization Andy Witmeier said, referencing the 2020 announcement that MISO and SPP would try a new approach to interregional planning after years of unsuccessful pursuits for transmission prospects.

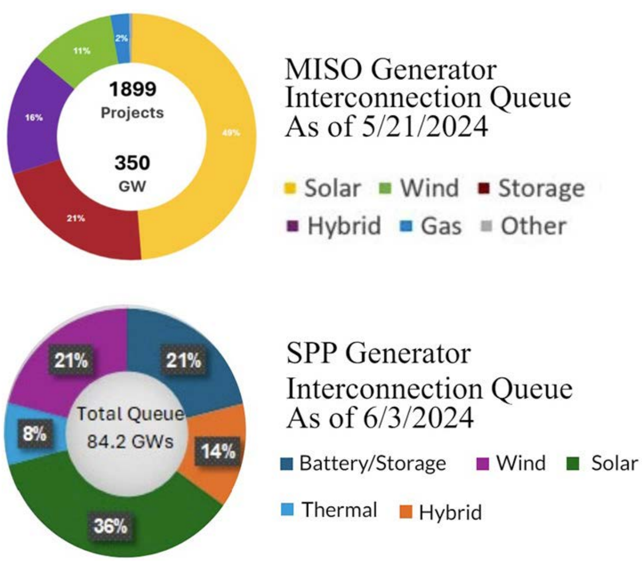
MISO counsel Chris Supino said the JTIQ process — which will replace MISO and SPP's affected-system studies — will allow generation developers to learn their cost responsibility earlier and get projects connected sooner.

Supino said the first portfolio represents the most "immediate need for beneficial, backbone projects" along the MISO Midwest and SPP seam. He said MISO may focus on MISO South for its next JTIQ portfolio with SPP.

Witmeier said the first portfolio should dramatically decrease the costs of getting generation online near the seam. He said a recent SPP affected-system study returned $1.4 billion in network upgrades for just 8 GW of projects connecting in MISO. On the other hand, Witmeier said the $1.8 billion JTIQ is expected to enable 28 GW in generation additions.

MISO and SPP are pursuing a 100% cost allocation to interconnection generation. The two initially planned to use a split entailing 90% to generators and 10% to load, but they abandoned the approach after the Department of Energy announced the portfolio would receive $464.5 million from the department's Grid Resilience and Innovation Partnership program. (See *MISO, SPP Ditch 90/10 JTIQ Allocation After $465M DOE Grant*.) MISO and SPP's load will act as a temporary cost backstop for their share of JTIQ costs until enough new generation commits to the lines and picks up the tab for construction.

Geissler said it's unlikely that load will have to cover any JTIQ costs permanently because of the sheer numbers of prospective projects in MISO's and SPP's interconnection queues. However, construction may begin on the JTIQ projects before they're fully subscribed. MISO said it will consider JTIQ portfolios fully subscribed when 85% of the megawatts they can enable are spoken for. For the first JTIQ portfolio, that subscription threshold will be a little more than 24 GW in generation projects.



MISO and SPP interconnection queue totals | *MISO and SPP*

Witmeier added that MISO load should benefit from lower congestion costs and decreased market-to-market payments once JTIQ projects are built.

SPP's interconnection queue boasts 412 projects totaling more than 84 GW; MISO's interconnection queue could approach 350 GW, if all the 123-GW 2023 class of queue applications are allowed to proceed. (See *MISO Reports 123-GW Roster for 2023 Interconnection Queue Cycle*.)

"The existing system was not designed to handle this level of generation," Supino said.

MISO expects to begin accounting for JTIQ projects in its generator interconnection queue study modeling next year, after the RTOs' boards approve the JTIQ portfolio.

MISO and SPP plan to study generation projects that may rely on JTIQ projects in clusters. MISO said it will screen projects and move those dependent on JTIQ into a "participation group." Generation projects will enter a "commitment group" once they close in on generator interconnection agreements and will be assessed a per-megawatt JTIQ charge that is billed directly by either MISO or SPP.

Sustainable FERC Project attorney Lauren Azar asked if MISO is planning to change JTIQ rules to integrate changes stemming from FERC's recent show-cause order issued to MISO and three other RTOs. The commission last week put the grid operators on notice that their policies allowing transmission owners the opportunity to provide initial funding for network upgrades may impede interconnection customers' right to finance the upgrades they pay for. (See *FERC Issues Show-cause Order on TO Self-funding in 4 RTOs*.)

"That's something we're still evaluating," Supino said. "We're still going to have to determine how this impacts it."

But Supino said that unlike normal upgrades that transmission owners can elect to self-fund, the JTIQ involves large projects that are prebuilt by transmission owners assigned by MISO or SPP.

"I'm not certain it's going to raise the same questions," Witmeier said. ■

OMS-MISO RA Survey: Potential 14-GW Capacity Deficit in Summer 2029

MISO Assumes 2.3 GW in New Capacity Annually

By Amanda Durish Cook

A relatively low turnout of constructed capacity in recent years could continue and deepen a potential 1-GW capacity deficit in summer 2025 to more than 14 GW by summer 2029, MISO and the Organization of MISO States revealed in their five-year resource adequacy projection.

According to the pair's 11th annual joint survey, the footprint could either enjoy a 1-GW capacity surplus or contend with a nearly 3-GW deficit by next summer. Much depends on how quickly developers can overcome obstacles to get new resources into commercial operation.

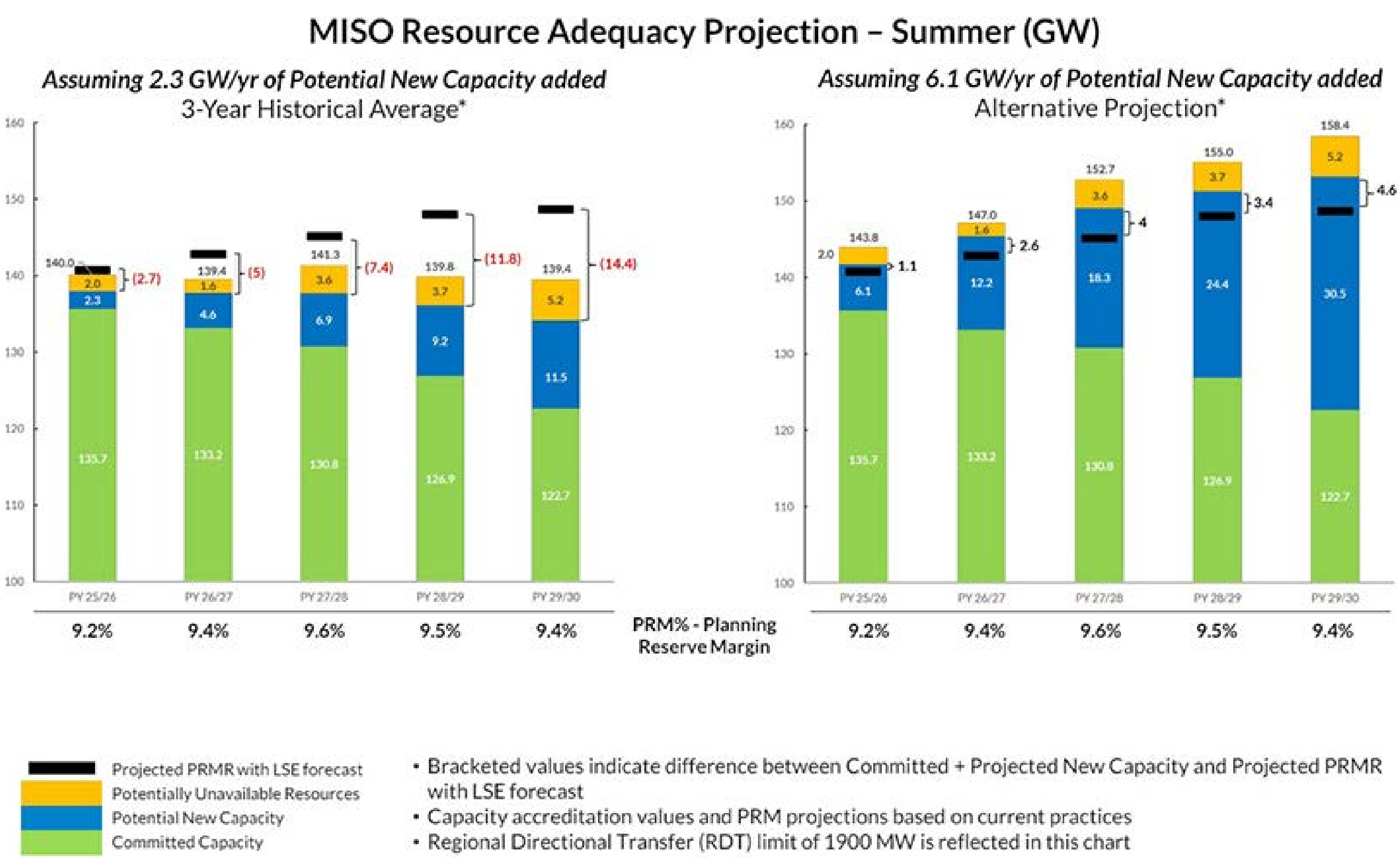
This year's *survey* assumed MISO will realize only about 2.3 GW/year in accredited capacity from new builds and did not designate projects with signed generator interconnection agreements as a foregone conclusion in committed capacity totals. The survey also didn't account for the size of MISO's record-breaking 300-GW interconnection queue and used a 9.2 to 9.6% planning reserve margin requirement over the next five years.

At the 2.3-GW/year rate — which is the historical average of what developers were able to connect in the past three years — a 5-GW capacity shortfall in planning year 2026/27 widens to 7.4 GW by 2027/28 and nearly 12 GW by 2028/29. Last year's survey anticipated a 9.5-GW shortfall by the 2028/29 planning year. (See *OMS-MISO RA Survey Signals Potential for 9-GW Shortfall by 2028*.)

This year's lower rate of assumed capacity additions spurred debate between MISO staff and stakeholders about what developers realistically can accomplish. That stalled the announcement of the survey results by a week.

During a June 20 teleconference to discuss the results, David Schoon, MISO resource adequacy engineer, said the RTO reflected a "new paradigm" from its interconnection queue in the survey. He said MISO's current 50-GW backlog of unfinished generation that's been approved to connect to the system but still is waiting in the wings influenced the survey's new method of evaluating capacity additions.

Schoon said MISO felt it needed to reflect the stubborn trends from the "COVID slowdown, such as continuing supply chain bottlenecks, commercial uncertainty and permitting and labor delays," despite what interconnection



OMS-MISO RA Survey capacity totals through the 2029-30 planning year with the 2.3 and 6.1 GW annual addition assumptions | *OMS and MISO* customers claim will be brought online.

"We've got to get out of that guessing game," Schoon said of the queue's annual yields. He said it's not realistic to assume developers can bring an "explosion" of resources online in a single year.

However, Schoon said MISO and OMS also contemplated that circumstances mend over time, and the footprint experiences an influx of skilled labor, a less fraught supply chain, expedited permitting and commercial viability of new technologies. In that alternative projection, MISO might connect more than double its three-year historical rate, at a little more than 6 GW annually.

At 6.1 GW/year, MISO could enjoy a 4.6-GW surplus by summer 2029.

However, MISO added a caveat that large, spot-load additions could balloon over the next five years and threaten a more than 30-GW shortfall under the 2.3-GW/year scenario and a nearly 10-GW shortfall even under the 6.1-GW/year rate.

"The situation is changing very rapidly around us," said Senior Director of Resource Adequacy Durgesh Manjure, referring to generation retirements and a resurgence in load growth through new data centers.

"Immediate actions are needed to expedite the addition of new capacity, coordinate resources for new load additions and potentially moderate the pace of resource retirements," Schoon said.

Josh Byrnes, OMS president and member of the Iowa Utilities Board, said RTO members' actions over the next year will matter a great deal. "We need to quickly move to make sure that new load doesn't outpace generation additions," he said.

Byrnes said the RTO should focus on ushering new capacity through its interconnection queue expeditiously and "use the expansive MISO footprint to the fullest" through regional transfers.

In a press release accompanying survey results, Byrnes stressed that as the region faces "tightening capacity reserve margins compounded with rapid and large load additions, it is imperative for everyone from developers (new load and generation), economic development authorities, utilities, regulators, MISO and other stakeholders to work in close coordination."

WEC Energy Group's Chris Plante asked if MISO has considered that load-serving entities with planned data centers in their territories will take pains to ensure they can cover the large load additions with new capacity or purchases.

MISO's Scott Wright said OMS and the RTO deliberated on the steps utilities and local governments will take to spur economic development.

"But we've also noted that laying it out this way highlights the fact that … a lot of these are un-resourced loads," Wright said.

Michigan Public Power Agency's Tom Weeks asked if MISO or its consultants mulled quantum computing emerging in time for the new decade, which could make data center energy consumption "plummet by orders of magnitude."

Schoon said such breakthroughs weren't included as possibilities in survey results. ■

NYISO News

NYISO: Prepared for Heat Dome Scorching New York

By Vincent Gabrielle

NYISO says it is prepared to meet demand during an extreme kind of heat wave called a heat dome that is already spiking temperatures to near 100 degrees Fahrenheit in western New York and is expected to spread this week throughout the state, northern New England and New Jersey.

"Based on current conditions, ... NYISO forecasts that there will be adequate supply of electricity to meet demand through the coming period of hot weather," Aaron Markham, vice president of operations, said in a press release June 18.

A heat dome is a high-pressure system in the upper atmosphere that traps warm air in place. Heat domes are more likely to arise in dry summer conditions.

According to the National Weather Service, Albany, Buffalo, Rochester, Syracuse and the Plattsburgh area will likely experience "extreme heat" with little to no overnight relief beginning June 19. The heat is expected to move east and south, hitting New York City on June 20. Dangerous heat levels could persist until June 23.

NYISO forecasts peak demand to reach as high as 28.9 GW by June 20. That is well below its forecast peak load for the season of about 31.5 GW, according to its Summer Assessment. The ISO will have about 40.7 GW of capacity available before derates, and operators could dispatch up to 3,275 MW through emergency procedures. (See *NYISO Reports Adequate Capacity for Summer, but Heat Waves a Concern*.)

| Shutterstock

Kevin Lanahan, vice president of external affairs and corporate communications, told *RTO Insider* that based on historical load data, weather conditions and modeling software, operations and planning personnel anticipate being able to meet demand.

"It's a technical process, and we've gotten pretty good at it," Lanahan said. "We have a lot of confidence in our planners and forecasters. We do believe we have enough power to meet demand."

Last year's peak demand of 30,206 MW was during the Labor Day heat wave. The all-time record peak of 33,956 MW occurred in July 2013.

New York Gov. Kathy Hochul *announced* she had activated the state's Emergency Operations Center. "New Yorkers should take every precaution to stay cool this week," she said. "Stay hydrated, avoid excessive outdoor activity and, if needed, visit a cooling center near you." ■

NYISO News

Moody's: 'Scars Remain' as New York's Economy Recovers

By Vincent Gabrielle

The economic forecasts for both New York state and the U.S. are reasonably healthy, stakeholders learned at NYISO's annual Spring Economic Conference on June 17.

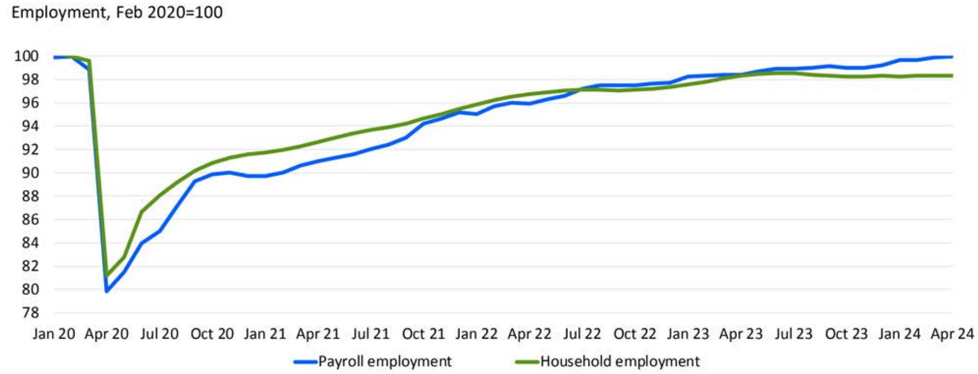
"The track that we're on is pretty sustainable," said Adam Kamins, senior director of Moody's Analytics. "It doesn't look like there's any sort of recession imminent."

Nationally, 200,000 to 250,000 new jobs were created every month in the fourth quarter of 2023 and first quarter of 2024. This was ahead of expectations and "far stronger than expected," Kamins said.

Kamins anticipates that while new jobs should level off nationally to closer to 100,000 per month, this is unlikely to cause additional inflation. Kamins attributed this to immigration, both documented and undocumented. New families are taking otherwise-unfilled jobs and growing the population.

"We've had a surge of immigrants come in and fill all of these jobs and continue to contribute to 250,000 jobs per month," Kamins said. "But it's not created this sort of inflationary pressure that we thought it would have if we took the census numbers at face value."

Later in the presentation, Kamins showed that New York state was among the top destinations for new immigrants, highlighting data from immigration court filings. Many were coming to New York City, but growth could also be seen in other metro areas of Albany, Rochester and Buffalo.



This graph shows the recovery of jobs for both the Bureau of Labor Statistics Payroll (blue) and Household (green) surveys of job creation for New York State. While there is a discrepancy between the two rates of growth, they show New York approaching pre-pandemic employment levels. | *Moody's Analytics*

Job growth in New York recovered slowly from the shock it endured during the pandemic, but it has recovered, Kamins said. He pointed to New York City as the primary driver.

"It's not being driven by the traditional kinds of jobs of the New York City economy. This is not runaway growth in Wall Street jobs," Kamins said. He explained that this was mostly consumer-facing jobs, driven by tourism and health care services.

The rest of the state has not recovered nearly as well, but Kamins said the outlook was pretty good for markets like Syracuse, Buffalo and Albany.

"Syracuse is clearly outgrowing the U.S. and is actually the second-fastest-growing metro area in the region," Kamins said.

He went on to highlight a "chip corridor" through the Capital Region and Central New York that extends into part of the Southern Tier and the Rochester area. This area is benefiting from the Biden administration's increased investment in computer chip production as new facilities come online.

"The bigger picture in New York is that, with all of the investment in chip production that's happened, Upstate New York is really becoming, if not the chip production capital of the U.S., [then] one of two or three [important] areas. … There's a huge opportunity here."

This "regional cluster" of chip production and similar high-tech industries could lead to substantial, sustainable growth, unlike the beleaguered Tesla electric vehicle facility in Buffalo, Kamins said.

At the same time, inflation seems to have slowed down such that it is back to the Federal Reserve's target of 2% per year. Rent growth has slowed nationally, and wage growth is catching back up to price growth. Kamins said Moody's anticipates the Federal Reserve will cut interest rates this year.

'Scars Remain'

Kamins cautioned that despite the stronger-than-anticipated economic picture, there were very real problems faced by consumers that have led to decreased confidence in the economy.

The past few years of inflation have outpaced wage growth, leading to an overall decrease in real wages.

"All these income quartiles, including the lowest earners, saw wage growth not keep up with inflation, meaning they're experiencing real wage declines," Kamins said. "That doesn't feel good for people, and the pain is very broad."

Kamins said this was particularly felt in lower wage earners who were already struggling to make ends meet prior to the increase in inflation. While the recovery in wage growth has begun, it hasn't made it to where it needs to be.

"We will need another year or so of wage growth exceeding growth in inflation, which we think will happen," Kamins said.

Another major constraint on the economy is housing. Kamins said that nationwide, including New York, lack of supply is driving

Adam Kamins, senior director of Moody's Analytics, gives a presentation on the economic outlooks for New York state and the U.S. at the Spring Economic Conference held by NYISO. | © *RTO Insider LLC*

NYISO News

increased home prices. He said that while the rate of house price growth was slowing, it wasn't at all close to declining. Builders just aren't building enough housing to meaningfully curtail prices. This is particularly pronounced in Buffalo.

High housing costs are partly responsible for New Yorkers migrating outward. While that has slowed in recent years, it's still persistent. Both young professionals and retirees are leaving the state for the Carolinas, Tennessee, Florida, Connecticut and New Jersey.

Novel Emission Considerations

The conference also featured two presentations about optimizing for carbon emissions impact on both the generation and consumption sides.

Lee Taylor, CEO of clean energy advisory firm REsurety, explained the problem of local marginal emissions, the emissions rate of a particular node of the electrical grid. This is the carbon-accounting version of LMP. As load and generation change hour by hour, the ratio of renewables to fossil fuels can change depending on weather, load demand and transmission bottlenecks.

"You have a highly impactful carbon footprint of the projects that are close to the city," Taylor said. "As you move up into the area toward the Canadian border, you get farther from the load, [and] the impact of the generation profile gets lower and lower in terms of its carbon offset."

This means that if a renewable energy project is sited far away from the point of delivery, it has less ability to reduce emissions near that point. Taylor noted wind projects close to Canada run often but are often either curtailed or end up competing with other renewables

Lee Taylor, CEO of REsurity, gives a presentation on the impact of transmission, load and generation siting on reductions in carbon emissions. | *© RTO Insider LLC*

because the power they produce can't get to where the load is.

Taylor said the renewable energy industry was starting to take this into account when determining where to build, optimizing for cheap emission reductions rather than simply building where it is cheapest.

"A project that is 50% more expensive to build but 70% more carbon-abative is actually cheaper when your goal is to spend the least amount of money to impact the highest amount of carbon, which is, ultimately, the goal of most voluntary carbon actors," Taylor said.

In addition to siting renewable projects in places where they would have the most emissions impact, large load customers are increasingly taking this into account when considering where to build their facilities.

"Businesses are cost optimizing," Taylor said. "They're looking for where does that go the furthest in dollar per ton of carbon."

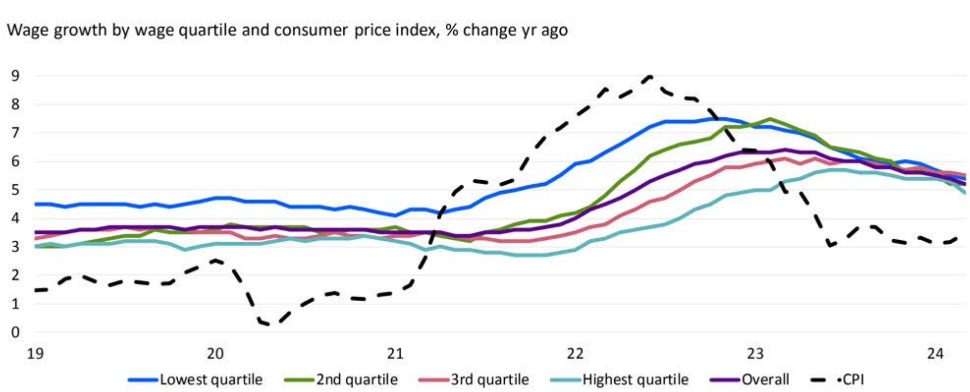
On the demand side of things, Gavin McCormick, executive director of nonprofit research group WattTime, said many companies were moving to smart load shifting to offset their emissions.

"We've just hit, as of today, 700 million devices worldwide that are optimizing every five minutes their consumption of electricity to reduce emissions," McCormick said. "All signs point towards sort of roughly a doubling per year for the next four or five years."

McCormick said this meant that about 20% of smart devices were committed, via software, to implementing this emissions-reduction strategy worldwide. While most of these devices are currently smart phones, McCormick listed several EV manufacturers, including Toyota, Honda and General Motors, as committing to this strategy.

McCormick said the impact of this load shifting on emissions wasn't clear yet. He said his organization had joined several universities, tech companies and grid operators to attempt to empirically research the impact of this kind of mass, distributed load shifting on emissions.

"We would be very interested in speaking with ISOs about whether we are measuring emissions correctly [and whether] the effects of this [is] what we believe them to be," McCormick said. "There's so much corporate interest in shifting load to the cleanest time that I think it should be recognized." ■



Wage growth moves back ahead of inflation, but scars remain | *Moody's Analytics*

Gavin McCormick, executive director of WattTime, a nonprofit research organization, gives a presentation on optimizing emissions-based load shifting as a way to reduce emissions. | *© RTO Insider LLC*

PJM News

Report Shows Wide Range of Data Center Demand Scenarios for Virginia

By James Downing

Growing demand from Northern Virginia's Data Center Alley could outpace the power industry's ability to keep up, according to a report released June 20 by Aurora Energy Research.

PJM's latest 2024 forecast shows 11 GW of demand from new data centers in Northern Virginia alone by 2030, which would represent 40% of Virginia's peak demand. In the report "*Impacts of Virginia data center demand growth on the power system*," Aurora says data center demand could reach as much as 16 GW by the end of the decade.

New supply would be needed to meet such demand, which the report said could drive up to 15 GW of new natural gas capacity because intermittent renewables alone would not provide the reliability that PJM market rules require. Dispatchable resources such as natural gas or battery storage would be needed to reliably serve new data center load, according to Aurora.

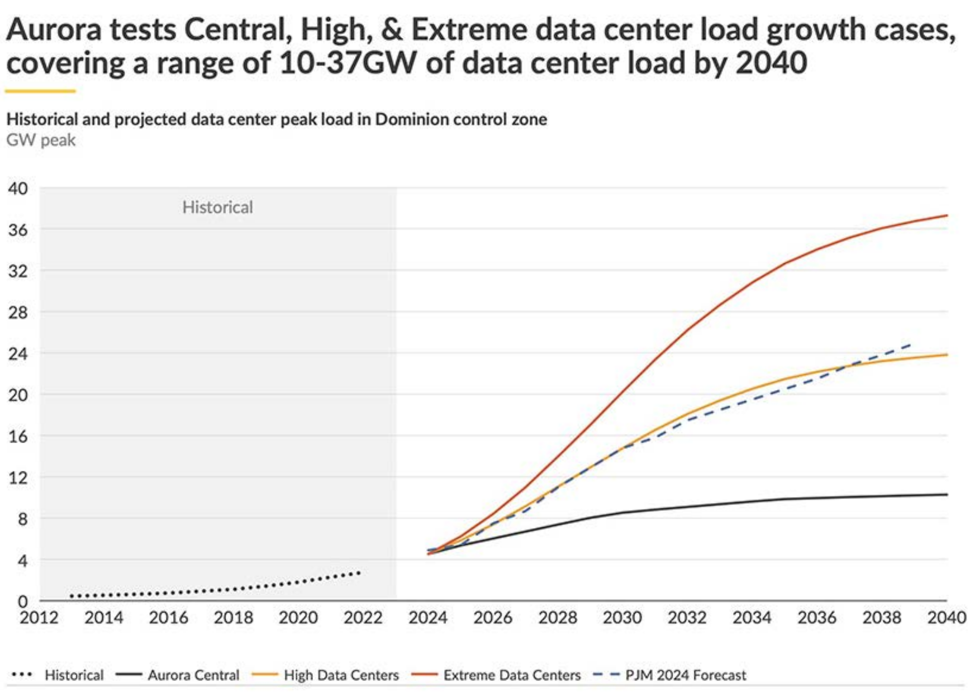
The need for new supply could affect data center demand growth, with the report noting new plants take years to get through PJM's interconnection process and connect to the grid. Relatively high power prices in Virginia and increasing geographic flexibility from data centers could drive them to be built elsewhere.

"Adding the 10 to 15 GW of firm generation capacity needed to supply these data centers and keep the lights on in Virginia will not be easy," Aurora's PJM Research Lead Zachary Edelen said in a statement. "It can take three to four years for the transmission organization just to greenlight a new generator, and market prices are currently too low for developers to build the kind of capacity required."

Renewable capacity grows significantly in PJM under all of Aurora's scenarios, which forecast a minimum of 40 GW of new nameplate capacity in the region. But renewables are credited well short of their nameplate capacity in PJM's capacity market and that along with data centers' need for steady power supplies lead to more need for natural gas plants and batteries.

"As a result, our analyses consistently show that data centers bolster the business case for natural gas generators, meaning state and federal governments will need to do more if they want to decarbonize," Edelen said.

Northern Virginia's Data Center Alley is home to 25% of national data center load. Its 4 GW of demand beat that of every country except the U.S. itself and China. Nearly 300 data center facilities are in Northern Virginia, with a cluster around Data Center Alley in Ashburn, according to the report.



| Aurora Energy Research

Growth was so fast there that Dominion Energy had to pause new data center connections in 2022 to avoid spiking congestion. Now the utility is implementing grid updates to deal with the bottleneck. Dominion expects 20 GW of new load and plans to invest nearly $5 billion in transmission to deal with that, according to the report.

Data centers are considering behind-the-meter generation as they work to improve efficiency in their operations in the face of high electricity costs in Northern Virginia, according to the report, which also noted the centers increasingly can locate elsewhere as internet connections improve.

Aurora's demand forecasts range from 10 to 37 GW by 2040; a 24-GW growth scenario is in line with PJM's load forecast.

Dominion forecasts 11 GW of additional capacity obligations for its footprint by 2030 and plans to buy and import about 59% of that from around PJM. Its transmission spending plans will help enable that.

The RTO will need more capacity to meet the Virginia data center demand because of planned retirements. Aurora forecasts a 12-GW shortfall in "unforced capacity," which would take 15 GW of new gas plants, or 20 GW of batteries if they hold four hours of charge.

The higher demand is expected to help push up power prices, with the forecast closest to PJM's adding $3/MWh to the average, but the extreme case of 37 GW by 2040 would add $16/MWh.

Data centers building their own generation could put a cap on how high their new demand drives wholesale prices, the report noted. A combined cycle gas turbine would make sense for big data centers if the generator's capacity factor is high enough, which would be the case at average data centers that have a load factor of 88%, according to the report.

"A strategy of building one's own behind-the-meter generation carries risks, including necessitating a long generator lifetime to realize benefits, policy risk (from potential decarbonization rules), outage risk and potential local pushback from neighboring residents," Aurora said in the report. ■

FERC Orders Settlement Judge Procedures in 2 PJM Generator Deactivations

By Devin Leith-Yessian

FERC has established settlement judge procedures to consider the validity of rate schedules filed by Talen Energy to continue operating its Brandon Shores and H.A. Wagner generators past their retirement date (*ER24-1787*, *ER24-1790*). (See *PJM Requests 2nd Talen Generator Delay Retirement*.)

The commission's June 17 order states that the proposed rate schedules may not be just and reasonable because of the calculation of the filings' valuations of the two generators. It also took issue with adjusting fixed operating and maintenance expenses for inflation using an escalation index, along with the proposed monthly project investment tracker payment and performance requirements.

"While we are setting these matters for a trial-type evidentiary hearing, we encourage the parties to make every effort to reach settlement before hearing procedures commence," the order states.

The filings requested annual fixed costs of around $175 million to keep Brandon Shores' 1,273-MW coal-fired generator online from June 1, 2025, through Dec. 31, 2028, as well as variable costs such as fuel and $29.9 million in project investments. The Wagner filing requests $40.3 million annually to keep two of Wagner's oil-fired units, amounting to 702 MW, online for the same period and $4.5 million in additional investments.

The reliability-must-run (RMR) agreement is intended to keep the generators online to avoid reliability violations identified throughout the Baltimore region while transmission reinforcements are constructed that would allow the units to deactivate without issue. (See *FERC Approves Cost Allocation for $5 Billion in PJM Transmission Expansion*.)

The proposed rates were opposed by the Independent Market Monitor and the Maryland Public Service Commission, who argued the rate schedules would improperly include sunk costs incurred prior to the start of the RMR term and unrelated to the going-forward costs of keeping the facilities operational.

The Monitor argued that including sunk costs that have already been reported as impaired assets would ask ratepayers to make investors whole for past losses.

The June 17 order accepted the rate schedules, suspended them and initiated the settlement judge procedures with the possibility of evidentiary hearings if that avenue does not yield a consensus.

The Brandon Shores coal-fired power plant | *Talen Energy*

Maryland Deputy People's Counsel William Fields said sunk costs make up a significant portion of the proposed rates and the Office of People's Counsel is preparing an analysis on how the RMR could affect state ratepayers. He said the office is pleased with the commission's decision to open settlement judge procedures and plans to fully participate.

"We don't view those as costs that are related to going forward with operations of the plant."

Fields said he believes PJM's backlogged generation interconnection process leaves few alternatives to expensive RMR contracts to keep retiring resources online while major grid reinforcements are constructed.

"We've got a few concerns with that approach or reliance on the market response here, and one is that this happens very quickly. You're talking months, and that is very, very quick for any kind of significant market response to a significant, pretty big retirement. Trying to respond to that with a lot of megawatts is going to be difficult in any circumstance, and right now, the PJM queue process is working through its backlog, and that makes it even more difficult for some kind of new resource to get through and get online on a time frame that's going to help the situation at all," he said.

Protesters also disputed the filings' methodology for determining the value of Brandon Shores and Wagner, depreciation and the amount of risk the company faces in continuing to operate the generators.

Monitor Joe Bowring said opportunity costs similar to those Talen is seeking to include in the rates have been rejected by the commission in past RMR filings.

The Brandon Shores filing also notes it's subject to a settlement agreement with the Sierra Club requiring that coal combustion at the site cease by the end of 2025. It states that it will seek changes to those terms to allow the generator to keep operating for the RMR term.

Casey Roberts of the Sierra Club said the organization is willing to engage with Talen on the agreement, but "additional protections for the local community and consumers, and longer-term reforms to avoid similar predicaments in the future, must all be on the table."

The club's protest of the rate schedule also urged the commission to not approve an RMR agreement that would pay for Brandon Shores to remain online until the agreement has been modified to allow the generator to operate.

"Thus, it appears on the face of the CORS [continuing operations rate schedules] that Talen intends not to operate Brandon Shores under the CORS unless its settlement agreement with Sierra Club is modified, notwithstanding the hundreds of millions of dollars in fixed monthly payments that Talen would receive even if it never generates a single megawatt hour. FERC cannot approve such an arrangement, particularly on the expedited basis that Talen seeks in this proceeding," the Sierra Club wrote.

Both the Sierra Club and Maryland Public Service Commission argued that the proposed rates lack performance requirements and would require load to pay significant sums to keep the two generators operational with no guarantee they would respond if dispatched by PJM.

Maryland PSC spokesperson Tori Leonard said the commission supports FERC's directive opening the settlement judge proceedings.

"FERC's preliminary analysis confirmed that both the Brandon Shores rate schedule and Wagner rate schedule have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful," Leonard wrote in an email. "This commission is pleased that FERC granted our request (as well as the request of the Maryland Office of People's Counsel), to set the matter for settlement judge procedures. The commission will continue to advocate for a reasonable resolution of the Brandon Shores and Wagner RMR filings that will minimize impacts to ratepayers, while preserving the reliability of the bulk electric power system to serve Maryland's needs." ■

PJM News

Order Expected on Complaint Against PJM over ELCC Resource Accreditation

By Devin Leith-Yessian

FERC is expected to issue an order during its June 27 open meeting on a complaint alleging PJM violated its Reliability Assurance Agreement (RAA) when accrediting intermittent resources (*EL23-13*).

Consultant Roy Shanker | *© RTO Insider LLC*

Filed in November 2022 by economist Roy Shanker, the complaint argues the RTO improperly included energy above intermittent resources' capacity interconnection rights (CIRs) when determining their capacity contributions. The practice was used for resources accredited through PJM's effective load-carrying capability (ELCC) approach.

The commission issued a March 2023 order accepting a PJM proposal intending to resolve the issue by modifying the ELCC analysis to cap the hourly output a resource is expected to be able to offer at its CIR level (*ER23-1067*). The commission also is slated to issue an additional order in that docket June 27. (See *FERC Approves Revisions to PJM's ELCC Accreditation Model*.)

The month prior to FERC's order granting PJM's proposal, Shanker argued against PJM comments asking the commission to dismiss his complaint, saying that even if the proposal resolved RAA violations going forward, that would not cure past violations.

| *© RTO Insider LLC*

The complaint asked the commission to adjust prior Base Residual Auction settlements "that are not time barred" and effectively implement its proposed cap on hourly output immediately without a transitional period. It requested an effective date of Nov. 30, 2022, and refunds through the implementation of PJM's proposal. ■

PJM MRC/MC Preview

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

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse proposed *revisions* to Manual 18: PJM Capacity Market to reflect redesigns drafted through the Critical Issue Fast Path (CIFP) process and approved by the commission in January (*ER24-99*). The changes expand the use of effective load-carrying capability in the accreditation of all generation classes, require that planned resources notify PJM of their intent to participation in auctions at least 90 days in advance and change how unforced capacity (UCAP) values are calculated. (See "Stakeholders Endorse Manual Revisions to Implement CIFP Changes to Capacity Market," *PJM MIC Briefs: May 1, 2024*.)

Issue Tracking: *CIFP Resource Adequacy*

Issue Tracking: *Local Considerations for Net Cost of New Entry*

C. Endorse proposed *revisions* to Manuals 14B: PJM Region Transmission Planning Process; 20: PJM Resource Adequacy Analysis; 20A: Resource Adequacy Analysis; 21: Rules and Procedures for Determination of Generating Capability; 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis; and 21B: Rules and Procedures for Determination of Generating Capability drafted through the CIFP process and accepted by the commission in ER24-99. The new language details PJM's new approach to risk modeling, how it simulates resource outputs and the definition of the capacity emergency transfer objective (CETO). (See "CIFP Manual Revisions Endorsed," *PJM PC/TEAC Briefs: June 4, 2024*.)

Issue Tracking: *CIFP Resource Adequacy*

Members Committee

Consent Agenda (1:50-1:55)

B. Endorse proposed tariff and Reliability Assurance Agreement (RAA) *revisions* addressing how capacity obligations arising from forecasted large load adjustments are assigned. (See "New Approach to Large Load Addition Capacity Assignments Endorsed," *PJM MRC Briefs: May 22, 2024*.)

Issue Tracking: *Capacity Obligations for Forecasted Large Load Adjustments*

Endorsements (1:55-2:05)

1. Nominating Committee Elections (1:55-2:05)

PJM Director of Stakeholder Affairs Dave Anders will *review* the sector nominees for the Nominating Committee's 2024/25 term.

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

— Devin Leith-Yessian

Company Briefs

ClearVue PV Selects San Jose for HQ

Solar developer ClearVue PV last week announced it has selected San Jose, Calif., for its U.S. headquarters.

Australia-based ClearVue has developed specialized glass technologies that can keep a window fully transparent and generate electricity. The window allows light to pass through the glass before redirecting the incoming sun rays onto cells that can generate electricity for a building.

The company expects to expand to 20 workers in San Jose.

More: *Redlands Daily Facts*

Ineos, NextEra Break Ground on Texas Solar Project

Chemicals company Ineos Olefins & Polymers USA, along with NextEra Energy Resources, announced they have begun construction of a 310-MW solar project in Bosque County, Texas.

A NextEra subsidiary will build, own and operate the INEOS Hickerson Solar farm. The companies hope to reach commercial operation by December 2025.

More: *Renewables Now*

Federal Briefs

EPA, DOE Announce $850M to Reduce Methane from Oil, Gas Sector

EPA and the Department of Energy last week announced that applications are open for $850 million in funding for projects that will help monitor, measure, quantify and reduce methane emissions from the oil and natural gas sector.

Oil and gas facilities are the nation's largest industrial source of methane, a climate "super pollutant" that is responsible for about one-third of the warming from greenhouse gases occurring today.

The funds are from the Inflation Reduction Act. Applicants are required to submit community benefits plans to demonstrate meaningful engagement with and tangible benefits to the communities in which the proposed projects will be located.

More: *EPA*

DOE Picks New Company for Hanford Site Work

The Department of Energy has picked a California company for a contract worth up to $8.3 million to administer worker's compensation claims at the Hanford nuclear site in Eastern Washington.

Innovative Claim Solutions will replace Penser North America, of Lacey, Wash., which has held contracts to do that work since 2009. The new contract has a one-year base period, followed by options for one-year extensions up to a total of five years.

The Penser contract, valued at $4.6 million when it was awarded, expires Sept. 30. A 60-day transition to Innovative will begin on Aug. 1.

More: *Tri-City Herald*

State Briefs

CONNECTICUT

Moody's Downgrades Eversource's CL&P to Negative Outlook

Moody's Ratings last week downgraded Eversource Energy's Connecticut Light and Power subsidiary to a negative outlook based largely on "an inconsistent and unpredictable regulatory environment."

The downgrade reinforces longstanding complaints by Eversource and United Illuminating, also recently downgraded, that their ability to raise capital is suffering from what they call "arbitrary" regulatory decisions that undercut their ability to earn on the hundreds of millions of dollars that they invest annually in clean energy projects and other grid improvements.

"CL&P's electric distribution business operates under the purview of the [Public Utilities Regulatory Authority], a regulatory framework that has become increasingly difficult due to higher political scrutiny and inconsistent regulatory decisions and rate case outcomes," Moody's said.

More: *Hartford Courant*

LOUISIANA

Craig Greene Won't Seek Re-election to PSC

Public Service Commissioner Craig Greene last week announced he will not seek re-election once his term concludes at the end of the year.

"When you know, you know," Greene, first elected in 2017, said in a news release. "For almost a decade, I've worked hard to keep a watchful eye on our utility providers, holding them accountable to keep prices affordable for the many families in our community struggling to get by."

Greene, who works full time as an orthopedic surgeon in Baton Rouge, said he will spend the extra time enjoying activities with his family and caring for his patients.

More: *Louisiana Illuminator*

MISSISSIPPI

Hinds County Approves Apex Solar Farm

The Hinds County Board of Supervisors last week voted 3-2 to approve the 396-MW Soul City Solar farm.

The 6,000-acre project, developed by Apex

Clean Energy, will be the largest in the state when completed.

Construction is planned to start this year and be completed by 2027.

More: *The Clarion-Ledger*

NEBRASKA

Oldest Operating Wind Turbines in State to be Removed

Lincoln Electric System will remove two 290-foot-tall turbines, installed in 1998 and 1999, in July, as they have reached the end of their productivity.

They were the oldest continuously operating wind turbines in the state, producing 1.3 MW combined. Both could have lasted a little longer, LES said, but it estimates it will save $100,000 by taking them down now.

Scott Benson, manager of resource and transmission planning at LES, said the turbines helped the utility learn enough about wind power to enter its first small contracts for wind farms. "We learned a lot from them."

More: *Nebraska Examiner*

NEW YORK

National Grid Says More Staff Needed to Comply with Climate Law

National Grid last week asked the Public Service Commission to raise annual electric delivery rates by $525 million a year across its upstate territory. If approved, the rate hike would raise the average monthly electric bill by $18.92 (15%).

National Grid said one of the reasons for its request is the state's 2019 Climate Leadership and Community Protection Act, as it is putting new pressures on the company to hire more employees to comply with the law.

"The company is seeking to add incremental [full-time employees] to support its customer programs," National Grid said in its filing with the PSC. "From a broad perspective [this] is necessitated primarily by the need to achieve the [law's] energy efficiency and emissions-reduction goals."

More: *Times Union*

NYSEG Fined $11.4M for Poor Customer Service Performance

New York State Electric and Gas was fined $11.4 million by the Public Service Commission for failing to meet all four of its customer service performance metrics.

NYSEG's sister company, Rochester Gas & Electric, also failed to meet all four metrics, resulting in a $7.1 million penalty.

"Ensuring that the utilities operation in New York state maintain good customer service is a top priority for the commission," said Chair Rory Christian.

More: *WETM*

Old Gas Line Left Open Caused Blast that Destroyed Syracuse Home

An explosion that collapsed a Syracuse house and injured 13 people last week was caused by an open natural gas line, fire officials said.

Fire investigators inspecting the basement noticed a gas line intended to feed a clothes dryer was not connected to an appliance. The gas line had an open valve and was free-flowing natural gas at the time of the explosion.

The landlord said there hadn't been a dryer hooked up to the gas line for years. The line was not capped and only had a shutoff valve that was found in the open position. The line should have been capped, officials said.

More: *Syracuse.com*

OHIO

Texts Show DeWine Initiated Dark Money Payment, Sparks New Bill

Newly revealed texts show that despite claiming no knowledge of the extent of FirstEnergy's dark money support for his gubernatorial races, Gov. Mike DeWine personally solicited money from CEO Charles Jones.

About a month before the 2018 election that launched DeWine into the governor's office, he sent a text to Jones — indicted earlier this year on bribery charges — looking for cash. Jones forwarded the text to Senior Vice President Mike Dowling, who also was indicted this year on bribery charges. A $500,000 "dark money" contribution was later made. DeWine has not been accused of any criminal wrongdoing.

The news has prompted Republican lawmakers to draft legislation requiring greater campaign finance disclosure from dark money groups.

More: *Cleveland.com*; *Ohio Capital Journal*

RHODE ISLAND

McKee Signs Legislation to Regulate Solar Companies

Gov. **Dan McKee** last week signed legislation designed to regulate solar companies and protect consumers from deceptive sales practices.

The act will require solar retailers to register both their business and a roster of their representatives soliciting sales. Retailers must also conduct criminal background checks on principal officers and sales representatives, as well as follow municipal restrictions on door-to-door sales and federal telemarketing rules.

The law will take effect March 1, 2025.

More: *WPRI*

VERMONT

Legislature Overrides Scott, Passes Renewables Bill

The state legislature last week overturned Gov. Phil Scott's (R) veto and enacted a law that requires utilities to source all of their electricity from renewable resources by 2035.

Scott had said the bill would be too costly for ratepayers. Under the legislation, the biggest utilities will need to meet the goal by 2030.

Senate President Pro Tempore Philip Baruth (D) called the governor's veto an attempt to continue rejecting "critical progress on climate action" at a time when residents are still facing "the impacts of recent climate disasters."

More: *The Associated Press*