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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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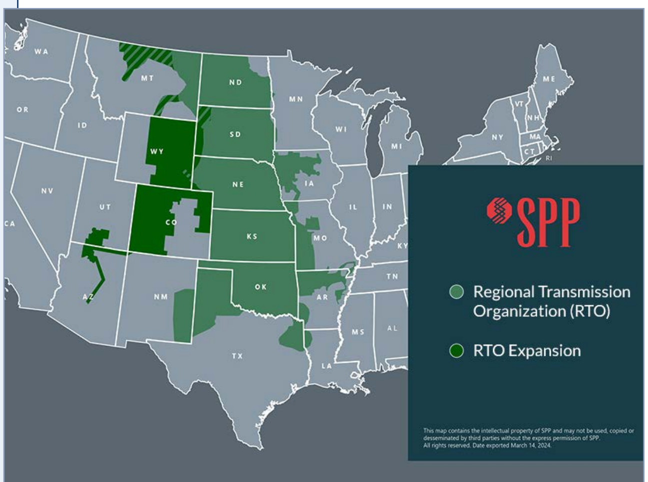
SPP

FERC Approves Tariff for SPP RTO West



SPP

FERC's acceptance of SPP's tariff revisions for its RTO West means SPP will be the first grid operator to provide full market services in both the Western and Eastern Interconnections.

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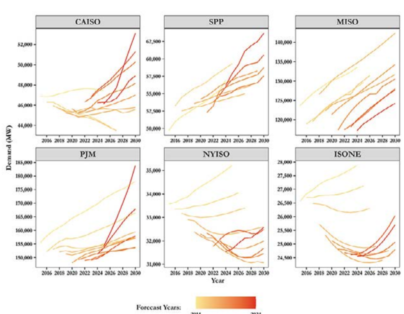
FERC/FEDERAL



FERC

FERC State of the Markets Report Shows Load Growth, Lower Prices

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Data centers are expected to add 13 to 55 GW in the next five years, amid uncertainty about supply chains, how efficient computation in artificial intelligence will be, and the availability of electric generation in some regions.

PJM

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The volatility of unit ratings after auctions has been a sticking point for generation owners, who say it is unfair to commit a resource in the auction only to reduce that unit's accredited capacity afterward.

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FERC Again Declines Changes, Refunds on Crypto-burdened MISO-SPP Flowgate (p.17)

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In this week's issue

FERC State of the Markets Report Shows Load Growth, Lower Prices

By James Downing

FERC on March 20 released its State of the Markets report, which showed higher demand and lower wholesale prices across the organized markets in 2024.

The higher demand was driven by a warmer summer, leading to higher demand peaks in CAISO, ERCOT and PJM, but the report also noted demand is expected to increase even more in coming years.

"Going forward, NERC forecasts that U.S. electric loads will grow more quickly and increase by 132 GW by the summer of 2029 and by 149 GW by the winter of 2029," the report said.

Generation of electricity was higher from 2023 to meet the demand, totaling 4,151 TWh nationally, though the resource mix continued to change. Coal generation was down 3.3% from 2023, utility-scale solar was up 32% and wind generation grew by 7.7%.

The lower national prices masked regional disparities, with ERCOT North Hub and trading hubs in the West seeing the steepest drops, while wholesale prices in the Northeast were up from 2023.

"Compared to the five-year average prior to 2023, electricity prices were down significantly in nearly all representative trading hubs, with the greatest decreases in ERCOT, CAISO, SPP and the Southeast," the report said. "In RTOs/ISOs, mean

Why This Matters

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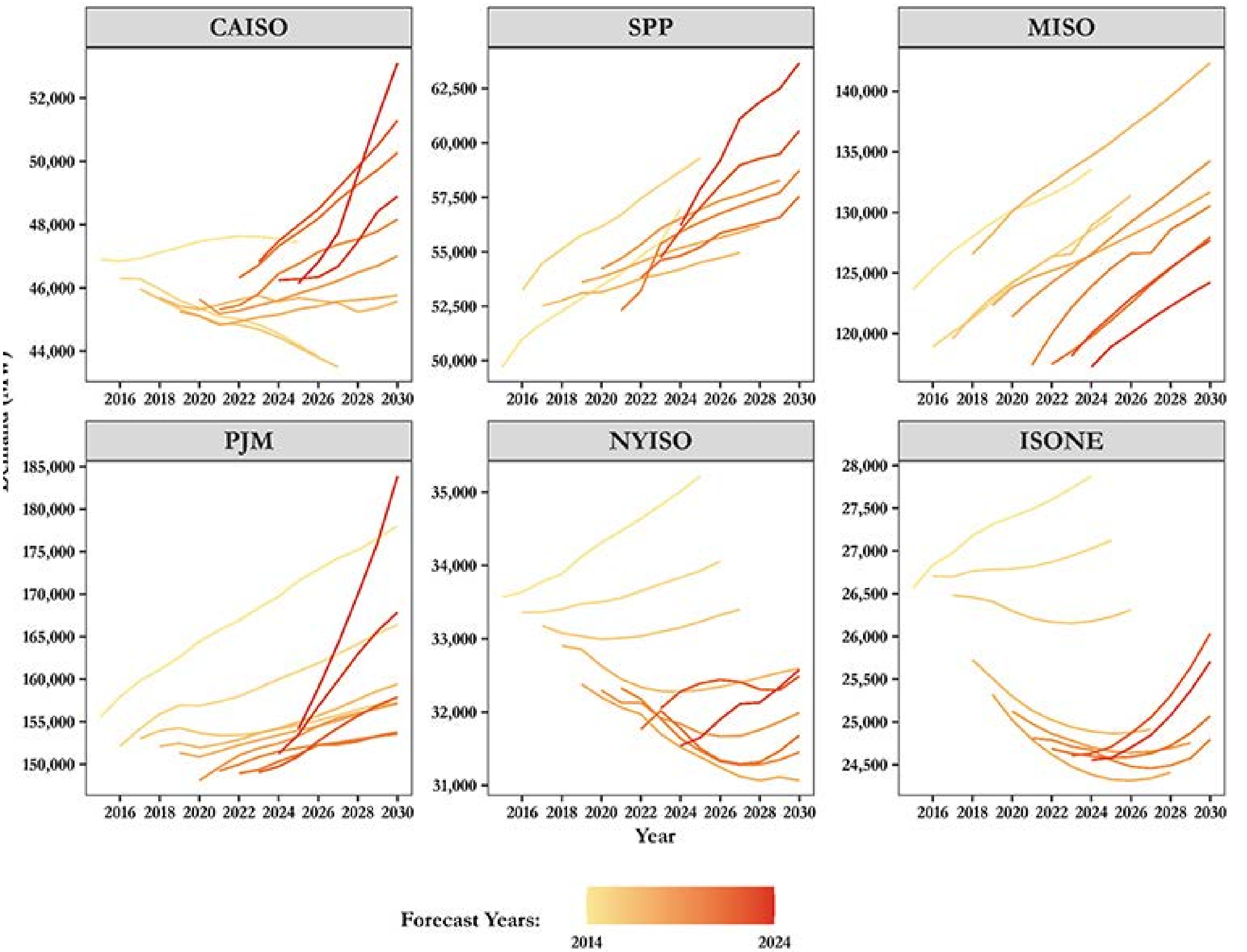

How demand forecasts have changed at ISO/RTOs in recent years | FERC

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load-weighted electricity prices were down 25% compared to the five-year average prior to 2023."

FERC Chair Mark Christie highlighted the regional differences in prices, saying that the State of the Market report from PJM Monitor Joe Bowring showed an uptick in prices there. (See *PJM Market Monitor Publishes Mixed Views in Annual Report*.)

"LMPs went up by almost 8%, and the overall total cost of wholesale power went up by almost 5%, so I'm not saying that it's a discrepancy, but PJM is the largest operator by load, and Dr. Bowring reports that their wholesale power costs went up almost 5%," Christie said.

The report shows wholesale prices going up by 4% at the node FERC tracks in PJM, but it does not examine all-in costs like Bowring's does, staffer Taylor Webster said at the commission's open meeting.

Beyond prices, Christie also highlighted that reserve margins are shrinking around the country.

"This report is consistent with reports we have been regularly receiving from NERC as well as RTO sources, such as from PJM and *MISO*," Christie said in a statement. "The combination of rapidly increasing electricity demand, driven by hyperscale customers such as data centers, paired with the alarming rate of baseload generation retirements and lack of new dispatchable generation, is not sustainable and must be addressed."

Data centers are expected to add 13 to 55 GW across the country over the next five years, with uncertainty about supply chains, questions about how efficient computation in artificial intelligence will be, and the availability of electric generation in some regions. The changing demand, resource mix and weather patterns all have had an impact on capacity markets, with *ISO-NE*, MISO, *NYISO* and PJM all seeing prices rise in those markets, the report said.

"Although the mechanisms differ, each of the nation's RTOs and ISOs are working to preserve resource adequacy by enacting changes consistent with their specific market structures," the report said. "Some of these changes have been enacted, while others are underway or on the horizon. The full effects of these resource adequacy reforms are not yet fully clear."

Commissioner Judy Chang noted the markets also feel the effects of cheap natural gas. Prices for the commodity were down from 2023, with the Henry Hub benchmark dropping 11% to average $2.25/MMBtu.

"I just want to make a note that our electricity prices are very sensitive to gas prices, I would say probably across the entire U.S.," she said. "But also, while energy prices are low, it also puts upward pressure on capacity prices."

That pressure is felt in regions like PJM, where prices shot up in a very visible way, but also in regions where capacity costs are included in bilateral contracts that power plants sign for offtake, Chang added. ■

FERC Approves Duke Energy's Order 2023 Compliance Filing

By James Downing

FERC on March 20 approved Duke Energy's compliance filing with Order 2023, which revised the commission's *pro forma* generator interconnection rules to speed up queues around the country (*ER24-1554*).

The changes to Duke Energy Carolinas' and Duke Energy Progress' large generator interconnection procedures (LGIP) and small generator interconnection procedures (SGIP) will go into effect Nov. 1, 2025, as requested, with the utility having to make an additional compliance filing within 60 days of the order to make some minor changes.

Duke proposed to adopt FERC's *pro forma* large generator interconnection agreement (LGIA), *pro forma* LGIP, *pro forma* small generator interconnection agreement and *pro forma* SGIP. Much of the other parts of Order 2023 were also adopted directly, but Duke also proposed some variations, which is allowed as long as they are consistent or superior to its baseline rules.

The utility had already implemented a cluster study process before Order 2023, which it proposed to keep in place but change some of the timing requirements to better align with FERC's new requirements.

It proposed to cut its 180-day cluster request window down to 45 days but leave the customer engagement window at 60 days, the Phase 1 Cluster Study deadline at 90 days, the Phase 2 study at 150 days and the as-needed Cluster Restudy at another 150 days. Individual facility studies are required to be done in 90 days or 180 days based on the interconnection customer's choice, instead of 150 in the current rules.

The two-phase study process has Duke study power flow and voltage in the first and then stability, short circuit and reactive capability in the second. The process allows the utility to work through the queue more quickly and efficiently and cuts the likelihood that it will need to do restudies, making it better than the default in Order 2023, it told FERC.

"We find that Duke's two-phase cluster study process overall satisfies the 'consistent with or superior to' standard by providing interconnection customers with Phase 1 study results and an opportunity to withdraw earlier in the study process, thereby increasing the speed and efficiency of the Phase 2 study," FERC said. "Duke's proposed two-phase process occurring over 90 days is, in this respect, faster than the commission's single-phase *pro forma* process, which takes an additional 60 days to conduct the cluster study and provide results to customers, after which they would have their first opportunity to withdraw from the queue."

| *Duke Energy*

Why This Matters

Duke won an exception for its two-study queue process but mostly adopted the *pro forma* changes from Order 2023 designed to speed up the interconnection queues.

Duke's proposal gives customers an earlier look at network upgrade costs, which allows them to make critical decisions about whether to move forward earlier in the process, the commission said.

Some intervenors were worried that the tight study deadlines left little room for error, but Duke said it has adopted all the aspects of Order 2023 designed to mitigate restudy risk.

"Moreover, Duke presents historical data showing that large percentages of its customers withdraw after Phase 1, and that retaining its two-phase process provides an opportunity to withdraw earlier in the process," FERC said. "In turn, we agree that a cluster study process that maximizes the likelihood of early withdrawals will also minimize study and queue administration costs for all customers."

Duke's proposed withdrawal penalties increase at each stage of the process, which is in line with the structure adopted in Order 2023, FERC said. It had to tweak that to fit its two-study process, requiring interconnection customers dropping out after Phase 1 to pay twice its actual allocated costs of all studies performed up to then, and those that drop out after Phase 2 to pay 5% of estimated network upgrade costs and then increasingly higher shares of network upgrade costs later in the process.

The utility removed penalties for projects not picked in resource solicitation processes, which FERC said was superior to its *pro forma* process by cutting barriers to entry to the queue. ■

DC Circuit Reverses Course on Vacating FERC Approvals of 2 LNG Sites

By James Downing

The D.C. Circuit Court of Appeals on March 18 *reversed* its vacatur of FERC's approvals of two LNG export facilities in Texas, having been convinced on appeal that the commission's procedural errors were not as serious as it had initially judged.

The court had vacated FERC's 2019 approvals of the Brownsville Shipping Channel and Rio Grande LNG in Cameron County, Texas, and remanded them for additional proceedings in 2024. (See *DC Circuit Vacates FERC Approval of Two LNG Facilities in Texas*.) The court's vacatur, along with another decision, led then-Chair Willie Phillips to consider changes to how FERC was reviewing natural gas infrastructure. (See *DC Circuit Orders Could Lead FERC to Rethink its Natural Gas Policies*.)

The three-judge panel's initial decision held that while the vacatur might cause significant disruptions to the projects, that did not outweigh the seriousness of the commission's procedural defects in the case. Among them was that, having its approvals already remanded in 2021, FERC did not conduct new environmental impact statements for the projects.

The court followed a precedent that vacatur is warranted when an agency commits a "fundamental" procedural error, such as skipping an environmental review altogether.

"The procedural steps the commission skipped here were important, but they were not 'fundamental' in the same sense," the same panel said. "The commission has already issued extensive final environmental impact statements reflecting more than three years of review and public comment."

While the decision reversed the vacaturs, FERC must undertake some additional environmental reviews of specific subjects, like Rio Grande's proposal to add carbon capture and storage to its facility.

"Against that backdrop, the seriousness of the reauthorization orders' deficiencies does not outweigh the disruptive effects of vacatur," the court said. "This court never doubted that vacatur would impose significant disruptive consequences … and respondent-intervenors have provided more details about those consequences in their rehearing petitions."

The complex, large-scale projects have been in development for more than eight years. The court agreed that vacatur would upend their construction schedules, prevent developers from meeting contractual obligations, and stall their ability to get financing and finalize labor contracts — impacting thousands of jobs.

President Donald Trump's executive orders on energy have also changed some of the legal questions, but the court declined to resolve new issues they brought up because doing so would not have changed its decision that vacatur was not warranted, it said. ■

| Cheniere

Utilities Ask FERC to Toss Local Tx Planning Complaint; Others Support It

Complaint Accuses TOs of Moving Projects into Local Processes to Avoid Oversight

By James Downing

FERC was flooded with comments on a wide-ranging complaint consumers filed seeking increased oversight of local transmission planning, with utilities arguing the complaint should be tossed, while others contend it has merit and raises issues that need to be addressed.

The complaint alleges that transmission owners around the U.S. have been moving more projects into local transmission siting processes because they fall into a regulatory gap with minimal oversight (*EL25-44*). To remedy that, the complainants contend, all lines rated at 100 kV and above should be regionally planned, and FERC should set up "independent transmission monitors" to oversee the planning process. (See *Consumer Groups Seek Independent Oversight of Local Tx Planning*.)

The complaint was lodged against every RTO and ISO and all other transmission planners under FERC jurisdiction.

In comments filed March 20, the Edison Electric Institute said the complaint "is anti-infrastructure, suggesting unworkable requirements that would stymie the development of necessary transmission projects at a time when substantial investment in transmission is needed to serve growing load, support generation expansion, and maintain reliability, as well as to support national security and ensure the United States is positioned to be economically competitive in the global market."

EEI echoed an argument common among opponents of the complaint: that in highlighting broad general issues with local transmission, the complaint failed to meet the burden of proof FERC requires to grant filings under Section 206 of the Federal Power Act.

"Complainants take pages to recount history, identify a host of transmission projects rated at 100 kV, cite to various studies in support changes that would apply nationally, apparently in service of ensuring that consumers are afforded 'economically efficient energy services at a reasonable cost,'" EEI said. "Yet, they draw no clear linkage between the recitation of history, listing of projects, and the requested relief."

Why This Matters

The complaint addresses an issue that has been bubbling for years: the trend of TOs developing projects under local processes with little regulatory oversight. Utilities want it dismissed, but others including some state regulators, want FERC to at least address the basic issues.

Like many other opponents, EEI said also that the complaint amounts to a collateral attack on previous FERC orders on transmission, including Order 1920. FERC considered requiring more oversight of local transmission and independent transmission monitors in the rulemaking process that led to Order 1920, but did not include those changes in the final rule.

"Local transmission investments are vital to enabling the interconnection of distribution resources, as even concentrated pockets of distributed resources can require localized transmission system reinforcements such as the reconductoring of lower-voltage lines or the construction of new substations," EEI said. "Local projects also enable transmission owners to nimbly develop infrastructure needed to effectuate state goals. In addition, upgrades to local, lower-voltage facilities are often needed to quickly meet changing system conditions and improve operational flexibility."

WIRES Group also urged FERC to reject the complaint, saying now is not the time to inject uncertainty into the transmission planning process given the challenges facing the grid.

"Utilities are facing potentially overwhelming demand driven by data centers, and artificial intelligence," WIRES said. "Investment in transmission infrastructure will enable the interconnection of new generation, the service of new load demands and efficient operation of the grid."

Centralizing all local planning at 100 kV and above would prove unworkable, WIRES said. Regional planners would have to replicate a public utility's in-house staff, including transmission and substation engineering experts, real estate specialists, field crews, environmental staff and operational personnel.

"It is difficult to conceive how a regional planner could fill those needs in a timely fashion, even if such experts were available for hire," WIRES said. "Complainants fail to explain how this transfer or duplication of staff, knowledge or expertise is even reasonable, efficient, or cost effective for customers."

On top of staffing, there are issues with handling data from local utilities that is often confidential, WIRES said.

NARUC did not weigh in on the specifics of the complaint, but it intervened to note that it had passed a resolution at the recent winter meetings that is related to local transmission planning oversight.

"NARUC urges the commission to act swiftly to put in place effective and robust transmission cost management and oversight processes for 'end of life' or 'asset condition' transmission projects in RTO regions, when requested by states within the region, with recovery of associated costs borne by those regions," it said in brief comments.

Regional Views

Some comments from individual states highlighted how inconsistent oversight for local transmission is at the state level.

The California Public Utilities Commission said any "repair and replace" projects that do not expand grid capacity are not included in CAISO's planning process. From 2019 to 2021, 63% of capital additions in the ISO's territory were "self-approved" by utilities.

"The proportion of spending on utility self-approved projects continues to be the overwhelming majority of transmission spending by California's three large IOUs and has actually increased over past years," the CPUC said. "In the most recent data from the CPUC's Transmission Project Review (TPR) Process, nearly 75% of the capital expenditures on the IOUs' transmission projects over $1 million for years 2020 through 2024, were on self-approved projects."

Cost estimates for new CAISO transmission required over the next 20 years range from $45.8 billion to $63.2 billion.

"Taken in its entirety, transmission investment in the CAISO in the next 20 years could be staggering, and measures are needed in the CAISO and elsewhere to enhance transparency and oversight of more transmission projects to promote affordability and to achieve the most cost-effective transmission grid possible," the CPUC said.

The New York Public Service Commission told FERC that local transmission projects in its territory are covered either through utility rate cases or state-run planning processes designed to meet the state's climate and renewable energy goals.

"While the complaint is directed at the NYISO, it implicates the traditional regulatory authority exercised by the NYSPSC," it told FERC. "The NYSPSC strongly opposes the complaint, which seeks a remedy that would preempt the NYSPSC's existing planning authority and rate oversight covering local transmission upgrades and replacements under state law."

New York's transmission owners agreed, saying FERC should deny the complaint for being legally and factually deficient.

"The ink is barely dry on Order No. 1920-A, rehearing requests are still pending commission consideration, and transmission providers across the United States — including the NYISO — are hard at work developing their compliance proposals," they said. "The commission, for its part, is actively overseeing compliance — a process that is both deliberate and essential to ensuring a smooth transition to a long-term orientation in regional transmission planning."

New England states generally supported the complaint, but the Maine PUC intervened to say that its review of local transmission projects offered enough oversight, though it couldn't extend that claim to the entire region.

"While the complainants correctly identified a regulatory gap present in New England, the MPUC submits that the one-size-fits-all remedy proposed by the complainants is inappropriate and should be rejected," the regulator said. "Any remedy to the regulatory gap identified by complainants should consider regional differences and provide for regional flexibility, especially since, as described below, there are already regulatory and state statutory frameworks in place that address certain aspects of asset condition projects."

The New England States Committee on Electricity agreed with complainants that the process in New England is not just and reasonable because asset condition projects are too lightly overseen.

"Unlike transmission projects in New England that ISO-NE selects to meet reliability needs through the regional planning process, the process to rebuild, refurbish or replace aged and damaged transmission facilities is conducted by individual and investor-owned transmission companies on an *ad hoc* basis," NESCOE said. "The scale of these projects, to a substantial degree, go beyond mere 'in kind replacements' and instead are leading to the massive reconstruction of the regional electric power grid. Yet, ISO-NE, the regional system planner, is largely shut out of this process."

While the New England states complained about the process there, some of the biggest transmission owners in the region (Avangrid, Eversource, National Grid and others) argued the process already benefits from oversight.

"The NETOs' [New England Transmission Owners] asset condition project planning process provides opportunities for state regulators, consumer advocates and other stakeholders to participate, ask questions and challenge projects before costs are allocated to customers across the region," they told FERC. "Additionally, the NETOs, the New England states and regional stakeholders have been working to further improve the transparency of asset condition project planning and enhance opportunities for stakeholder participation in that process."

The complaint also led to a split among PJM stakeholders, with the Organization of PJM States Inc. filing brief comments at least agreeing that FERC should deal with the issues highlighted in the complaint.

"Local planning of transmission in the PJM region has vastly outstripped regional planning in recent years, and thus retail consumers have not been able to reap the benefits of regional, more holistically planned projects," OPSI said.

OPSI did not take a position on the complaint, but said it wants FERC to address the proliferation of locally planned transmission projects with finality.

PJM, on the other hand, urged FERC to reject the complaint.

"The complainants failed to bear the burden of demonstrating with substantial, specific evidence that PJM's regional planning provisions are unjust and unreasonable because they do not also encompass local transmission planning," the RTO said. "PJM's regional transmission planning authority stems from that granted by the PJM Transmission Owners which have each turned over operational control of their interstate transmission systems to PJM, and reserved for themselves the continued right to local transmission planning."

Some Ask 'Why Us?'

With its broad allegations against the entire industry, some of the respondents questioned why they had been cited in the complaint in the first place.

SPP noted that its planning process largely already aligns with what the complaint wants, but it was still compelled to file a response. A group of its transmission owners, including American Electric Power, Evergy and Xcel, agreed with the RTO.

"As a threshold matter, the complaint should be dismissed outright with regard to the Southwest Power Pool and the SPP TO Group because the complaint concedes that 'SPP's regional approach is consistent with the relief requested nationally through this complaint,'" the SPP transmission owners said. ■

CAISO, EDF Trading Settle Fuel Cost Recovery Dispute

FERC Approves Settlement over La Paloma Gas-fired Plant Expenses

By Elaine Goodman

FERC approved a $528,000 settlement March 20 that ends a dispute between EDF Trading North America and CAISO over fuel cost recovery.

The settlement approved by FERC's order (*ER25-526*) resolves all issues that had been set for hearing.

EDF Trading has served as scheduling coordinator and fuel supplier for CXA La Paloma, which was also a party to the settlement. CXA La Paloma owns the 1,124-MW natural gas-fired La Paloma power plant in Kern County, Calif.

EDF Trading filed a request in July 2021 to recover "prudently incurred fuel costs" that were not reimbursed through market revenues Feb. 16, 2021. On that date, CAISO committed two units at La Paloma through its Residual Unit Commitment (RUC) process, which the ISO describes as a reliability function for committing resources and procuring RUC capacity not reflected in the day-ahead schedule.

But CAISO did so using gas prices to compensate La Paloma "that were well below the actual gas costs incurred," EDF Trading wrote in a fuel cost recovery application filed with FERC on July 29, 2021 (*ER21-2579*).

The cost-recovery issues with CAISO arose from "a perfect storm of events," including an "untimely notice from CAISO, a long holiday weekend and an extreme weather event," EDF Trading said in the filing.

CAISO had planned to implement changes to its cost-recovery procedures in early 2021 through tariff changes known as the Commitment Costs and Default Energy Bid Enhancement (CCDEBE).

On Sunday, Feb. 14, 2021, CAISO sent out a notice saying it would begin deploying CCDEBE the following day, which was Presidents Day, a holiday. The notice failed to give the two days advance warning that CAISO had promised, according to EDF Trading's filing.

That Sunday and Monday were also when Winter Storm Uri was striking Texas. EDF Trading said it faced "operational difficulties" due to rolling blackouts and internet problems.

CAISO denied recovery of fuel costs from the Feb. 16 La Paloma commitment, because the request to adjust the reference level using actual fuel costs was not made before 8 a.m. Feb. 15, EDF Trading said in its filing.

But the actual fuel costs weren't known at that time, EDF Trading said, because CAISO didn't commit the units as part of RUC until later that day.

"Equity requires ensuring that EDFT and La Paloma are not penalized for CAISO's failure to timely plan and notify market participants, particularly when EDFT and La Paloma ultimately performed and ensured system reliability," the filing said.

In February 2024, CXA La Paloma was purchased by Capital Power Investments LLC. Interest in the cost-recovery proceeding was retained by the seller, CXA La Paloma Holdco LLC. ■

La Paloma Generating Station in McKittrick, Calif. | *Capital Power*

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PUC Adds 2 More Projects to Texas Energy Fund

By Tom Kleckner

The Texas Public Utility Commission has advanced two generation projects for due diligence review as part of the Texas Energy Fund's In-ERCOT loan program, filling a hole left by two proposals that dropped out earlier this year.

The PUC accepted staff's recommendation during its open meeting March 13 to add NRG Energy and Vistra projects to the TEF portfolio. The companies are seeking $548 million in TEF funds for their 895 MW of potential new generation (*56896*).

NRG plans to add a 455-MW, quick-start natural gas peaker at its Greens Bayou facility outside Houston. Vistra has proposed a second Permian Power 440-MW natural gas peaker in the Permian Basin. Permian Power I, one of the first projects selected, would be built next to Vistra's existing 325-MW gas unit near Monahans in West Texas.

PUC attorney Laurie Hobbs said staff prioritized applicants that meet the commission's priorities, including speed to market, ability to relieve transmission constraints and diversity of dispatchable resource types.

"We're really trying to still balance as many of the [commission's] original policy priorities … but we must present you with applicants that can begin timely construction of their projects," she told the commissioners.

Why This Matters

The goal of the program is to add more dispatchable generation to the grid to prevent adequacy problems. The two projects replace two others that dropped out earlier this year, taking more than 1 GW of capacity with them.

Barksdale English, the PUC's deputy executive director, answers questions on the Texas Energy Fund. | *Admin Monitor*

ENGIE Flexible Generation NA withdrew a 930-MW peaking facility from consideration in February, and Howard Energy Partners pulled back a co-generation facility in January. Both companies said supply chain issues would delay the projects and keep them from meeting a December 2025 deadline for initial loan disbursements. (See *2 Companies Withdraw Texas Energy Fund Projects from Consideration*.)

"We need to make sure as best as we can that any project we approve going forward can meet these deadlines and be online," PUC Chair Thomas Gleeson said.

The In-ERCOT portfolio has 19 applications, totaling 9,774 MW of new gas generation, for $5.37 billion in loaned TEF funds.

Deputy Executive Director Barksdale English told the commission that Vistra generator Luminant, NRG, Constellation Energy and Calpine account for 35% of the TEF projects. He said adding more participants would increase competition.

Constellation said in January it plans to acquire Calpine, the nation's largest operator of geothermal and natural gas power generation. (See *Constellation to Acquire Calpine for $29.1B*.)

The *TEF* was created by the Texas Legislature in 2023 to add more dispatchable generation to the grid and was approved by voters later that year. Managed by the PUC, it is designed to provide grants and loans to finance construction, maintenance, modernization and operation of electric facilities in the state.

The fund is composed of four programs: In-ERCOT Generation Loans; In-ERCOT Completion Bonus Grants; Outside-ERCOT Grants; and Texas Backup Power Package. ■

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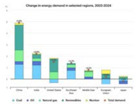

IEA: Extreme Weather Adds 20% to Increase in Electricity Demand in 2024

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ISO-NE Scales Back Heating, Vehicle Electrification Forecast

By Jon Lamson

As part of a major overhaul of its annual load forecasting process, ISO-NE has significantly *scaled back* its electrification forecast for electric vehicles and heat pumps.

Prior forecasts relied heavily on state EV targets to estimate load growth due to a lack of data on EV adoption. ISO-NE has compiled data over the past few years, enabling it to better estimate the actual adoption rates in the region, said Victoria Rojo, supervisor of load forecasting and system planning at ISO-NE.

"Comprehensive vehicle registration data has indicated that prior forecasts have exceeded actual EV registrations," Rojo told the Planning Advisory Committee on March 19.

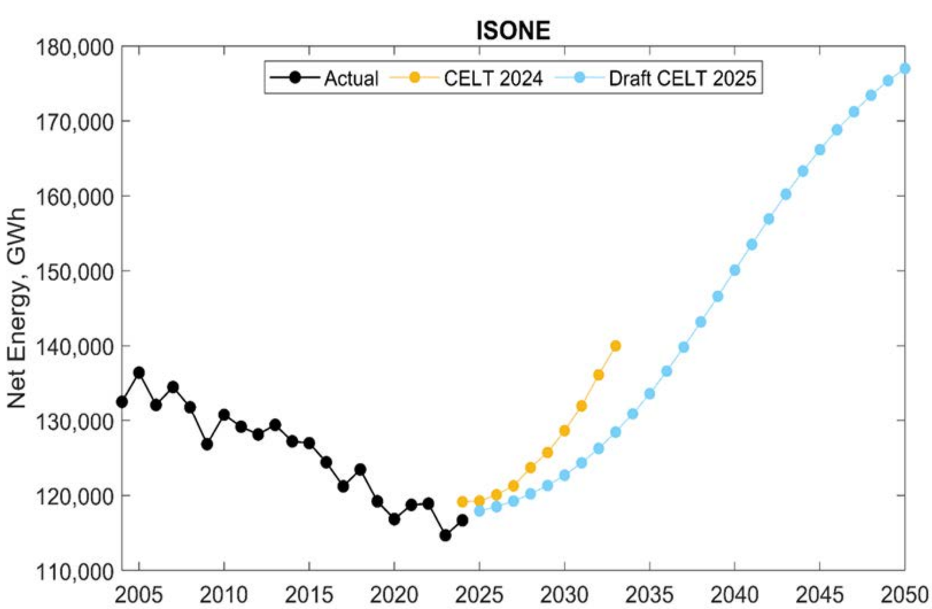
ISO-NE has *indicated* its 2024 Capacity, Energy, Loads and Transmission (CELT) report overestimated the adoption of personal light-duty vehicles by more than 70%. As a result, the RTO is reducing its adoption forecasts for all classes of electric vehicles.

To a lesser extent, the RTO also has reined in its forecast for heat pump adoption in the region, reducing its 2025 adoption expectation for Connecticut by 30% and for Massachusetts by 15%. The changes aim to account for "state policies, goals and [the] best available historical installation data."

While ISO-NE still expects heating and transportation electrification to increase substantially long-term, the updated adoption numbers significantly decrease the energy forecast for the upcoming decade. In its draft CELT forecast, ISO-NE reduced its annual net energy projection for 2033 by 8.2%, from 140,001 GWh to 128,460 GWh.

The RTO also cut its summer peak load projection for 2033 to 26,663 MW, a 1.4% reduction, and dropped its winter peak projection to 24,440 MW, an 8.7% reduction.

This is the second straight year ISO-NE has scaled back its demand forecasts. In 2024 it reduced its 10-year summer peak load forecast by 1.8% and its winter peak by 2.5%. (See *ISO-NE Decreases Its 10-year Peak Load Forecast*.)



ISO-NE net energy forecast | *ISO-NE*

Why This Matters

The slow adoption of electric vehicles and heat pumps is a bad sign for state climate targets but could delay some of the winter reliability challenges ISO-NE anticipates will arrive in the 2030s.

An ISO-NE study looking at 2032 — which relied on the elevated 2023 CELT forecast — found limited risk of shortfall on the New England grid, with the greatest risks coming during extreme winter weather scenarios. (See *ISO-NE Sees Little Shortfall Risk for 2032*.)

The electrification adoption changes are one component of a revamped forecasting methodology ISO-NE has rolled out for its 2025 CELT report. The new modeling capabilities will enable the RTO to estimate hourly power demand in each load zone more than 20 years into the future. The modeling will rely on zonal, county-level forecasts of electric vehicles, heat pumps and behind-the-meter solar.

"Each forecast component (base load, EV, HP and BTM PV) reflects coincident weather over a 70-year simulation period and are combined into forecasts of net and gross load for each zone and the region," Rojo noted.

The new methodology also introduces "climate-adjusted weather data reflecting 70 weather years," Rojo said. ISO-NE previously had not included the effects of climate change in its CELT forecasts.

The modeling also uses energy efficiency as an input to the model, eliminating the need for a separate energy efficiency forecast.

The RTO plans to publish its final CELT forecast in May. ■

New England Officials Discuss Tx Oversight and Rising Energy Costs

By Jon Lamson

BOSTON — State energy officials emphasized the need for increased oversight of transmission investments at Raab Associates' New England Electricity Restructuring Roundtable.

In recent years, costs associated with asset condition projects (ACPs), a class of transmission investments aimed at upgrading or replacing aging and degrading infrastructure, have grown significantly. State officials and consumer advocates call for changes to the process of reviewing these projects.

"We think it's critical to get a handle on this sooner rather than later," Phil Bartlett, chair of the Maine Public Utilities Commission, said at the March 21 roundtable.

Transmission owners already have made some changes to increase the transparency into ACP projects in response to requests from the states, including periodically releasing public data on under-development and in-service projects. ACPs classified as proposed, planned or under construction total nearly $6 billion, with major additional projects set to be introduced in the coming months. (See *ISO-NE Planning Advisory Committee Briefs: March 19, 2025*.)

The states continue to raise the lack of oversight for ACP spending and have called for the creation of an independent transmission monitor (ITM) "as a means of ensuring transmission costs are transparent and closely scrutinized."

"The transmission owners are the sole determiners of what is an asset condition project," Bartlett said. "These projects flow through FERC formula rates, so FERC isn't taking a close look at them, there's no process for ISO-NE to take a close look at them, and most of the states don't have the authority to dig in and look too closely at them, so we think there needs to be some regional mechanism to make sure that there is reasonable accountability."

In a filing to FERC on March 20 (EL25-44), the New England States Committee on Electricity (NESCOE) asked the commission to require that all "transmission investments recovered through the Regional Network Service rate be planned through an ISO-NE-administered regional transmission planning process."

From left: Melissa Lavinson, Massachusetts Office of Energy Transformation; Chair Phil Bartlett, Maine Public Utilities Commission; Commissioner Katie Dykes, Connecticut Department of Energy and Environmental Protection; Janet Gail Besser, moderator | *© RTO Insider*

Why This Matters

Changes to the asset condition project approval process could enable transmission owners to properly size the projects to meet future needs, while providing increased scrutiny into a major bucket of transmission spending.

NESCOE also asked FERC to "adopt, in the nearest term, NESCOE's longstanding request to implement an Independent Transmission Monitor," adding that the specific responsibilities of the ITM "should be developed by the region to meet New England's current region-specific needs."

The states expressed concern the planning process for asset condition projects does not adequately consider "whether the transmission facilities from the grid of yesterday are actually needed for the grid of today or are the right projects to account for new resources creating new demands on the transmission system."

"We want to make sure that [ACPs] are part of, or consistent with, a regional plan," Bartlett said at the roundtable. "Instead of having every transmission owner simply operating in a silo, let's make sure that those investments fit within a cohesive and sensible regional strategy."

Commissioner Katie Dykes of the Connecticut Department of Energy and Environmental Protection echoed Bartlett's concerns about asset condition oversight and said New England has seen a 72% increase in transmission costs since 2015, which now make up about 10-11% of electricity bills for residential consumers in Connecticut.

She highlighted a white paper published by the state in February that emphasizes potential cost savings associated with correctly sizing asset condition projects and incorporating advanced transmission technologies into transmission solutions.

Dykes stressed the importance of "ensuring that ratepayers can continue to trust that the increased amount of their dollars that is going to these projects is being reasonably spent."

Without effective oversight, "we can't really give that assurance," Dykes said.

In an interview following the roundtable, Dave Burnham, director of transmission policy at Eversource, said the company is committed to working with the states and other stakeholders to improve ACP procedures and is open to discussions about creating an independent entity to review ACPs.

"I think it's been a natural evolution from adding more transparency to now asking: 'what should we do with this information?'" Burnham said. "We completely understand the desire from the states to have somebody looking at these projects with an independent view."

He agreed that the region should establish a process to evaluate the proper sizing of ACPs when the projects overlap with obvious needs for increased transmission capacity. While asset condition projects often incidentally increase capacity, ACP projects typically do not aim to add capacity beyond these incidental gains, Burnham said.

He expressed his hope stakeholders can reach an agreement on an acceptable set of oversight and planning changes and said, "we don't believe that FERC coming in and imposing a one-size-fits-all solution is the right thing to do."

Incorporating Retail Demand Response

Speakers also highlighted the potential of demand response to help limit supply costs and reduce the need for additional grid infrastructure.

"There are all these retail programs that, for a variety of reasons, aren't participating in the wholesale market," said Bartlett, who leads a working group on retail demand response and load flexibility for the New England Conference of Public Utility Commissioners.

He expressed his hope the region can establish a simple, standardized mechanism to submit retail DR program information to ISO-NE "so they can see what's coming … and therefore build it into operational planning, and down the road have conversations about how to ensure we are compensating these resources."

Erika Diamond of EnergyHub stressed the need to make it easy for customers to understand and engage with demand response incentives.

"Our whole thing is trying to figure out how to make it as simple as humanly possible," Diamond said.

She said the ConnectedSolutions program, which extends across multiple states and utility service territories in the Northeast, is a good model for reaching customers and vendors.

Marketing across "a vast territory with the same message is far easier than going utility by utility," Diamond said, adding that "having a really simple program design has also really helped … along with making sure the compensation is the best fit for the technology."

Fossil Infrastructure Updates

State officials at the roundtable also answered questions about the role of fossil fuel infrastructure as the region decarbonizes. The Trump administration has pushed to expand natural gas pipeline capacity, and Connecticut Gov. Ned Lamont (D) recently *expressed an interest* in additional gas capacity.

"If there are ways to make investments to help … address reliability challenges in the early 2030s that don't result in stranded costs and do help shave overall costs on the electric bill," Dykes said, "that may be a path to ensure that more people aren't scared away from switching over to heat pumps and electric vehicles because of the sticker shock on their electric bill."

Meanwhile, Melissa Lavinson, director of the Massachusetts Office of Energy Transformation, discussed the state's ongoing work to reduce its reliance on the Everett LNG import terminal. The facility is under contract with the state's gas utilities until May 2030, but the Massachusetts Department of Public Utilities has directed the utilities to work with the state to "reduce or eliminate their reliance" on the import terminal. (See *Massachusetts DPU Approves Everett LNG Contracts*.)

Lavinson said Everett is "an important asset for the state and the region," but also is an expensive asset with volatile fuel costs and ultimately is incompatible with long-term state climate laws. She added that the state's "focus is on the ratepayer" as it charts a future beyond the facility.

Massachusetts has been explicit in its goal to reduce its reliance on natural gas to meet its climate targets, and any efforts to expand pipeline capacity there likely would face strong political opposition. (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

"Here in Massachusetts, we have very strong climate and clean energy laws — and I want to be really clear: laws," Lavinson said. "And we are working very hard to comply with those and do it in a way that increases our energy independence, creates jobs and reduces our reliance on volatile, expensive fuels." ■

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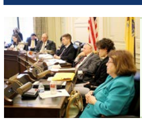
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Maryland Crossover Day Update: Bills Passed, Amended, Waiting
NetZero Insider

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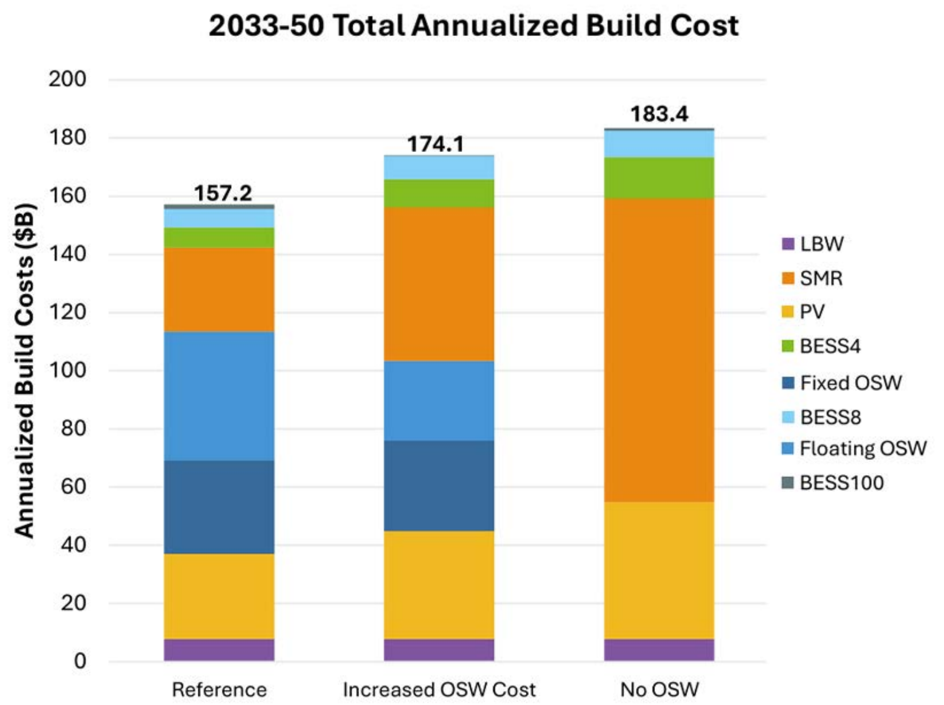
ISO-NE Planning Advisory Committee Briefs

Additional Economic Study Results

At the ISO-NE Planning Advisory Committee on March 19, Richard Kornitsky and Ellie Ross *presented the results* of additional modeling scenarios for the RTO's 2024 Economic Study, which aims to evaluate the effects of state and federal policies and changes to the region's resource mix through 2050.

Previous findings of the study have illustrated how the region's resource needs are expected to shift in the 2040s as the power system decarbonizes, corresponding with an exponential increase in the cost of additional carbon reductions. (See "2024 Economic Study," *ISO-NE Details Evaluation Models for Transmission Solicitation*.)



ISO-NE modeled total annualized build costs, 2033-2050 | *ISO-NE*

Building on the prior results, ISO-NE modeled a scenario evaluating the retirement of thermal resources. The model found the region could retire "up to 5,550 MW of legacy thermal (non-nuclear) generation" by 2050 without exceeding the loss-of-load expectation (LOLE) threshold, which was set at 0.1 days per year with a loss-of-load event.

"The retirement of 5,550 MW of legacy thermal generation has minimal impact on system operations in the 2050 production cost model," Ross said. "In the model with retirements, this generation is easily replaced by remaining [natural gas] generators."

She noted that the scenario caused a decrease in generation from thermal resources that burn landfill gas, municipal solid waste and wood waste solids, which resulted in an overall increase in the emissions from natural gas and oil.

ISO-NE also modeled scenarios featuring increased capital costs for offshore wind resources and no OSW buildout.

Adopting the National Renewable Energy Laboratory's conservative cost estimates for OSW — instead of the moderate estimates used in the model's base case — increased total annualized build costs by about $17 billion, or 10.8%.

This cost estimate still was cheaper than the no-OSW scenario, which increased build costs by about $26 billion, or 16.6%, compared to the base case.

"New England needs new OSW resources to meet state emission goals at the lowest cost," Ross said. "The buildouts with less or no OSW must rely more on emitting generation, [small modular reactors] and new [solar] resources."

"Even if OSW capital costs are higher than current estimates, the system will economically benefit from new OSW resources, although the ideal time frame for building OSW shifts to after 2040," she said.

Asset Condition Projects

Rafael Panos of National Grid introduced an asset condition *project* (ACP) to replace wooden structures, insulation, conductor and shield wire on a 115-kV line in Massachusetts.

The wooden poles set to be replaced, which have an average age of 30 years, have significant woodpecker damage, Panos said. He said the population of woodpeckers in New England has grown in recent years, causing significant damage to wooden transmission structures.

The company plans to replace the wooden poles with steel structures; Panos said he has observed woodpeckers pecking at steel structures, "but fortunately, they were not able to get through."

The project's projected cost is $19 million, and the expected in-service date is the second quarter of 2026. Stakeholder comments are due April 2.

Panos also presented a cost update on a project overhauling a substation in Tewksbury, Mass. The company has increased its cost estimate on the project to about $67 million, compared to the $36 million estimate presented in 2022.

The increase was driven by additional issues found at the substation and rising costs of labor, equipment, materials and permitting, Panos said.

Project List Update

New England transmission owners have added 10 ACPs to ISO-NE's tracking list since the previous update in fall 2024, said Brent Oberlin, executive director of transmission planning at ISO-NE. (*See New England Transmission Owners Issue Draft Asset Condition Forecast Database*.) The TOs estimate the projects collectively will cost about $730 million.

ACPs categorized in the database as proposed, planned or under construction total $5.97 billion, while the total cost of in-service ACPs is $5.36 billion.

This estimate does not include a series of projects proposed by Eversource to replace its network of underground high-pressure, fluid-filled transmission lines in Eastern Massachusetts. The company estimates the first phase of these replacements will cost between $1.5 billion and $2 billion and plans to provide more detailed cost estimates to the PAC in the summer. (See *Eversource Outlines Billions in New Boston-area Asset-condition Needs*.)

ACP costs in New England have ballooned in recent years, spurring calls from some consumer advocates for more transparency and oversight to ensure projects are cost efficient and right sized to account for future transmission needs.

"Despite the eye-watering sums being spent on ACP upgrades, they are not being designed to maximize the amount of power that can be carried via transmission lines in existing rights of way," the Acadia Center wrote in a recent *blog post*. "Each ACP that fails to maximize the capacity of existing transmission represents a lost opportunity to prepare New England to meet the projected doubling of the region's peak demand."

Connecticut 2034 Needs Assessment

Sarah Lamotte, transmission planning engineer at ISO-NE, presented the *results* from ISO-NE's Connecticut 2034 Needs Assessment, which is intended to "identify the time-sensitive and non-time-sensitive needs in the study area."

The study identified time-sensitive minimum load needs at 21 of the 115-kV buses and 27 of the 345-kV buses in the region.

Lamotte said the study considered non-transmission solutions and found they would not alleviate the time-sensitive issues. She said ISO-NE plans to initiate a solutions study in the second quarter of 2025 to address the identified needs.

Boston 2033 Solutions Study

Aqeel Ahmed, associate engineer at ISO-NE, presented the *preliminary results* of the RTO's Boston 2033 Solution Study, which is intended to address time-sensitive, minimum-load, high-voltage needs.

The preferred solution identified includes the installation of a 115-kV reactor and protection systems upgrades at five substations. The projected cost is $26 million. ■

— Jon Lamson

NEPOOL Reliability Committee Briefs

Load Power Factor Audits

Dean LaForest of ISO-NE presented the *results* of the RTO's 2023/24 load power factor (LPF) audit, which found most regional LPF areas to be noncompliant with the standards for low-load, high-voltage conditions.

The system generally graded out better on the standards applying to high-load, low-voltage conditions. However, within regional areas found to be compliant with the standards, regional entities frequently were out of compliance with the standards, ISO-NE found.

LaForest said ISO-NE found "no significant improvement year-over-year in LPF zone compliance." He said gaining more insight into transmission and distribution operators' systems "should help focus efforts on where compliance improvements within a zone are needed the most."

He noted that ISO-NE will share more specific details of the audit directly with the region's transmission and distribution operators.

Transmission Cost Allocations

Also at the NEPOOL Reliability Committee (RC), stakeholders approved transmission cost allocations for a pair of Eversource infrastructure replacement projects.

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The projects, located in Connecticut, include relay replacements on a substation and replacements of aging and deteriorating transmission structures. The projects combined have an estimated $15 million in pool transmission facility costs.

Transmission Outage Scheduling

Anthony Stevens of ISO-NE discussed a series of minor changes to the RTO's operating procedures governing transmission outage scheduling. The changes will explicitly allow the RTO to approve long-term transmission outages without first having to issue an interim approval of the outages. The changes also clarify the definitions of outage statuses and add language about "alternate dates" used for repositioning outages.

Stevens also presented changes to the RTO's operating procedures for metering and telemetering criteria. ISO-NE proposes to expand the equipment temperature range to allow for "additional conditions in which data center type HVAC redundancy is in place," Stevens said.

ISO-NE plans to seek a vote on the operating procedure changes at the RC in April.

Also at the meeting, stakeholders voted to support changes to ISO-NE operating procedures regarding protection outages, settings and coordination. ISO-NE proposes to "add language clarifying that automatic sectionalizing schemes do not require OP-24 Appendix D forms." ■

— Jon Lamson

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MISO Fields Divergent Calls for Stronger South Planning, IRA Reversal in Tx Futures

By Amanda Durish Cook

NEW ORLEANS — Calls to consider a dissolved or weakened Inflation Reduction Act alongside appeals for stronger MISO South planning epitomized the tough situation and unsteady political climate MISO finds itself in as it tries to establish transmission planning expectations.

In a transmission planning futures teleconference March 19, MISO revealed it plans to proceed in its modeling as if tax credits from the Inflation Reduction Act are a safe bet. However, MISO staff said they would consider performing sensitivities on the side if that federal funding is eliminated or diminished.

MISO is revising the trio of 20-year futures scenarios it uses to plan transmission. The RTO has said it must incorporate more aggressive load growth and would create a fourth scenario specially designed to study the footprint if frayed supply chains continue to present an obstacle to new generation construction.

WPPI Energy's Steve Leovy asked whether MISO is considering creating a separate resource expansion model should the IRA fall.

MISO Senior Manager of Policy and Regulatory Planning RaeLynn Asah said the sensitivities would produce "modified" and "miniature" resource expansion directions that wouldn't be tested for resource adequacy. But she stressed that MISO hasn't decided whether it will add the additional study step.

Asah said MISO typically uses sensitivities to "test the durability" of its resource expansion assumptions.

"There are a lot of rules and laws that appear to be rolling back this year," said Kavita Maini, representing MISO industrial customers.

"As of right now, as of March 1, the IRA is in place, so we're incorporating it into the model," Asah said, explaining that MISO's future modeling relies on a "snapshot" in time. MISO began building the futures models on March 1.

Why This Matters

Stakeholders are simultaneously asking MISO planners for meaningful long-range planning in the South and to consider striking the IRA from its 20-year planning futures.

Asah said MISO "has no idea" how the IRA will hold up or how funding cancellations or claw backs might be challenged in court.

Multiple stakeholders pointed out the IRA's demise is not as improbable as it was last year.

Mississippi Public Service Commission consultant Bill Booth asked if MISO could include an IRA downfall in its new, fourth future that's meant to contemplate long-term supply chain delays and sluggish generation construction.

"I think this will have a major impact on the generation that's sited," Booth said. "You have to question which variables MISO wants to include and which variables MISO wants to ignore."

MISO Director of Strategic Initiatives and Assessments Jordan Bakke said MISO is confronted with uncertainties at every turn in its futures planning. He said that's why MISO's futures include a range of possible realities. Bakke also said MISO wants to capture what it knows today, which includes an intact IRA.

"We have not decided which of the futures we will use in expansion planning," Executive Director of Transmission Planning Laura Rauch added.

MISO plans to focus on its new, fourth future in an upcoming April workshop. Another May workshop will focus on resource expansion assumptions and how resources would be dispersed across the footprint.

Asah asked members to submit their most up-to-date information on planned generation retirements to MISO. The RTO will incorporate those dates in its futures.

Spotlight on MISO South Planning

Stakeholders' advice to MISO to rethink the IRA's place in the futures comes as MISO and its board are fielding calls to action for a long-term transmission plan in MISO South. The two bids appear to come from opposing sides of the political spectrum.

After MISO completes a futures revamp over 2025, it will use them to plan another long-range transmission plan (LRTP) portfolio for MISO Midwest, making a MISO South LRTP portfolio years away while the Midwest region would be the focus of three, multibillion-dollar portfolios within six years.

At MISO's March Board Week, Windy Beck, of the Deep South Center for Environmental Justice, made a plea for in-depth MISO South planning. She said the region deserves the same planning attention paid to the Midwest. Beck said she's seen no evidence from MISO that Entergy and other South transmission owners' billions in annual Transmission Expansion Plan (MTEP) projects are the most cost-effective and efficient projects for the grid.

During the March 13 board meeting in New Orleans, CEO John Bear pushed back on the perception that MISO is not doing anything on the planning front for MISO South and focusing all planning attention on MISO Midwest.

Bear said MISO planners have "rolled up their sleeves" to ensure the transmission solutions put forward in the South as part of the MTEPs are "efficient, reliable and at the lowest cost."

However, the Union of Concerned Scientists' Sam Gomberg said the member-submitted project ideas of MISO South are no substitute for the broad analysis completed under a long-term planning exercise.

He said MISO South desperately needs the added resiliency, reliability, cost savings and delivered clean energy like the billions in Midwestern long-range lines will provide. ■

FERC Again Declines Changes, Refunds on Crypto-burdened MISO-SPP Flowgate

By Amanda Durish Cook

FERC once again decided that neither MISO nor Montana-Dakota Utilities are entitled to recourse over a MISO-SPP flowgate in North Dakota strained by a cryptocurrency mining facility.

The commission denied both MISO and Montana-Dakota Utilities' requests for rehearing in a March 20 order (*EL24-61 et al.*). It said it found nothing amiss with the 230-kV Charlie Creek flowgate's continued eligibility for market-to-market (M2M) coordination despite high congestion costs.

FERC first denied MISO and member Montana-Dakota Utilities Co.'s separate complaints over the Charlie Creek flowgate in September 2024. The two had argued that the congestion caused by the new cryptomining operation should fall to SPP alone because it's a local issue brought on by data center load growth. But FERC said neither MISO nor Montana-Dakota Utilities proved that Charlie Creek failed to meet the criteria for M2M coordination, nor was SPP in the wrong for continuing to insist on M2M coordination. (See *FERC Refuses MISO, MDU Complaints Regarding Crypto-strained MISO-SPP Flowgate*.)

FERC kept that stance in its latest order. The commission pointed out that the Charlie Creek flowgate passed some of the studies required under MISO and SPP's congestion management process to be eligible for M2M coordination. It also said it was unconvinced that MISO and SPP's interregional coordination process laid out in their joint operating agreement is unreasonable.

MISO had said the flowgate, which serves the 200-MW Atlas Power Data Center, cost its members more than $40 million in unjustified M2M payments. The RTO argued it could provide little congestion relief for SPP's transmission-constrained northwestern North Dakota load pocket. MISO also accused SPP of defying the two's M2M coordination protocol by refusing to revoke the line's M2M designation and insisting on interregional help for a provincial issue that MISO was powerless to resolve. Finally, MISO complained it couldn't veto the M2M status of the line without SPP's consent. (See *MISO Argues to FERC for 2nd Look at Crypto-stressed Flowgate Management* and *SPP, MISO Clash over Crypto-strained M2M Flowgate*.)

But FERC disagreed with MISO that the M2M process is unfair because it doesn't account for cost causation. The commission said MISO and SPP's coordination process is established on forecasted allocations with no requirement that the hundreds of M2M flowgates it serves be reviewed individually. The commission said such a style of cost allocation isn't meant to be roughly commensurate with estimated benefits.

FERC noted SPP's argument that about 20 other M2M flowgates at the seams "possess arguably 'local' attributes and impose 'higher than expected' congestion costs on SPP that require [M2M] payments to flow from SPP to MISO." The commission said a single flowgate in particular cost SPP $12.5 million in M2M payments to MISO in fall 2023.

FERC also disagreed with MISO that it and SPP's interregional coordination process is one-sided because it doesn't allow one RTO the ability to revoke an M2M designation.

The commission also said it didn't buy MISO's argument that it doesn't have enough generation nearby to help alleviate congestion on Charlie Creek. On the contrary, FERC said MISO operations contribute to congestion on the flowgate, where it serves load in the Williston, N.D., area. Flowgate studies from MISO and SPP's coordination process show the line is "significantly impacted" by MISO flows from generators that exceed 5% in real-time, FERC said. It added that SPP confirmed that if the flowgate was withdrawn, it might have to resort to transmission loading relief.

FERC decided against ordering SPP and MISO to make any specific adjustments to their M2M coordination process, as MISO requested. It ended by asking them to work together.

"We encourage the parties to continue negotiating prospective revisions to their agreements, especially in light of SPP's and MISO's positions that similar issues are either currently occurring on other [M2M] flowgates or are likely to recur on other [M2M] flowgates in the future," FERC wrote.

Additionally, FERC disagreed with Montana-Dakota Utilities' complaint that a combination of congestion charges and M2M payments stemming from Charlie Creek caused it to be double-charged.

The utility claimed it was billed for the same congestion once under the SPP tariff and again to reimburse MISO for M2M coordination. But FERC said the two are "distinct charges provided for under different frameworks that serve separate purposes." It explained one is incurred as a customer of SPP while the other is meant to cover interregional coordination charges.

In a separate but related docket on FERC's March 20 agenda, the commission also turned down MISO's request to waive SPP's yearlong statute of limitations on resettlements (*ER24-1586-001*). MISO was counting on FERC to allow a prolonged resettlement period to refund affected members some of the M2M payments, had FERC directed refunds. SPP said that allowing settlement adjustments outside of the window would amount to retroactive ratemaking. ■

Why This Matters

FERC told MISO and Montana-Dakota Utilities they must live with tens of millions in congestion costs at the MISO-SPP seam after a cryptomining center in North Dakota went live in 2023. Commissioners also refused ordering changes to the MISO-SPP interregional coordination process, which manages flowgates.

FERC OKs Incentives on $1B Minn. HVDC Modernization, Debates Procedure

By Amanda Durish Cook

FERC granted rate incentives for the priciest project to come out of MISO's 2024 Transmission Expansion Plan (MTEP 24), setting off friction between commissioners.

FERC approved Allete's request for abandoned plant and construction work in progress incentives on a $1 billion modernization of subsidiary Minnesota Power's circa-1970 HVDC line. The March 17 order had two commissioners disagreeing with how incentives were awarded on at least some of the work (*ER25-948*).

The commission fully allowed the pair of incentives for the portion of the line in Minnesota — where the certificate and route permitting already are approved — and conditioned incentives for the North Dakota portion of the line on state regulators' approval of construction. In North Dakota, work awaits an order from the Public Service Commission on certificate and route permit applications. Allete said that decision is likely in the third quarter of 2025.

Allete sought transmission rate incentives under FERC's rebuttable presumption that the line supports reliability or reduces congestion. The company said the project being subjected to MTEP studies and its ultimate inclusion in the portfolio is evidence of its usefulness.

MISO approved most of the four-part project under a seldom-used "transmission delivery service project" category as part of MTEP 24. (See *MTEP 24 Reaches $6.7B; MISO Ending Rush Island Reliability Agreement in Mid-October*.)

Allete said the aging, 465-mile line stretching from west-central Minnesota to central North Dakota is experiencing more frequent outages. The company breaks down the project into four components: $828 million in converter station replacements, $112 million in AC transmission facilities upgrades, a $68 million HVDC transmission line upgrade and a new, approximately $24.5 million Nelson Lake substation.

However, FERC said the project's MTEP status didn't prove it was the result of a fair and open regional planning process that accounts for reliability and congestion benefits. The commission cast doubt that MISO would perform the usual, comprehensive studies on that particular category of project. It also pointed out the project's Nelson Lake substation is categorized as an "other" reliability project and also not obliged under MISO's more rigorous studies.

The commission instead relied on the state commission processes in Minnesota and North Dakota for the project to meet the federal standard for incentives.

FERC paused before approving incentives for the $68 million line-upgrade section of the project. The commission acknowledged there's almost no chance the Minnesota and North Dakota commissions would explicitly evaluate the upgrade of existing line because the work wouldn't alter the original voltage, and the project would remain within its existing right of way. Nevertheless, FERC decided the line is "integrally related to the other components" and therefore also entitled to incentives.

Wtshymanski, CC BY-SA 3.0, via Wikimedia Commons

Why This Matters

A modernization of Minnesota Power's nearly 50-year-old HVDC line had FERC commissioners disagreeing over the proper channels to award rate incentives.

Commissioner Lindsay See said while she was "glad" to agree with the majority on most of the incentives, she said she would have stopped short of granting Allete incentives for the line-upgrade portion of the project. She dissented in part from the order.

Commissioner Willie Phillips wrote in a separate concurrence that while he was pleased the project ultimately won incentives, he was troubled that FERC would conduct an on-the-spot reevaluation of MISO's transmission delivery service project classification and deem it deficient against the rebuttable presumption standard.

Phillips also said the commission deviated from precedent without explanation when it made the effective date of a portion of the incentives contingent on North Dakota's approval of construction instead of the March 18, 2025, effective date Allete requested for the entire project.

"As such, this order represents an attempt by the current commission to modify our longstanding policy on transmission incentives on a case-by-case basis," Phillips wrote. "Our practices are not set in stone, and I believe it is both reasonable and appropriate to continually reassess and reevaluate them based on experience, changed circumstances, and achieved wisdom.

"But to do so in the context of an uncontested application, without notice or opportunity for interested parties to comment on these changes, lacks transparency and creates regulatory uncertainty that could undermine the very purpose of FPA [the Federal Power Act]." ■

7th Circuit Lifts Injunction on Indiana ROFR, Remands LS Power's Case

Court Decides LS Power Should Have Named MISO, not Indiana Regulators, in Lawsuit

By Amanda Durish Cook

The 7th U.S. Circuit Court of Appeals has tossed a temporary injunction against Indiana's right of first refusal law and sent the case back to a lower court, leaving plaintiff LS Power with more work ahead of it to increase competitively bid transmission projects in MISO.

The court decided LS Power's arguments were directed at the wrong party and said the company should have named MISO, not the Indiana Utility Regulatory Commission (IURC), as the source depriving it of the chance to bid on long-range transmission projects. The appeals court remanded the case to the district court that issued a preliminary injunction against the right of first refusal (ROFR) law and vacated the injunction (*25-1024*). The controversy again awaits proceedings from the U.S. District Court for the Southern District of Indiana.

The higher court concluded in its March 13 order that LS Power lacked standing to request the injunction because MISO is the entity responsible for assigning projects from its long-range transmission portfolios to developers. The court also said that because the preliminary injunction was meant for Indiana regulators alone, MISO isn't beholden to the ban.

The case has raised questions about who administers Indiana's ROFR law.

LS Power, a competitive transmission developer in MISO, has claimed for months that Indiana's ROFR is unconstitutional and violates the dormant commerce clause by treating in-state developers differently from out-of-state developers. The company won a preliminary injunction barring Indiana regulators from enforcing the law in December 2024, days before MISO approved a $21.8 billion long range transmission plan for MISO Midwest, raising doubts on who could build projects in the state. (See "Indiana ROFR Reversal Complicates Project Assignment," *MISO Board Endorses $21.8B Long-range Transmission Plan*.)

LS Power

What's Next

With its case headed back to district court and a preliminary injunction canceled, competitive developer LS Power must do more to revoke Indiana's right of first refusal law.

'An Unusual Situation'

The 7th Circuit acknowledged the case presented "an unusual situation," with gray area over whether IURC has the authority to enforce the state's ROFR. It eventually sided with counsel for the Indiana commissioners, who said commissioners are powerless to designate or reassign developers to the regional transmission projects MISO plans and approves.

"Even the subsections of the statute that mention the IURC make clear that the IURC functions only as a notice repository, not as an enforcer of the rights of first refusal," the court said of the IURC's role in the ROFR. It said a "genuine redress would have to operate against" MISO.

However, the district court reasoned months before that because IURC enforces the ROFR, MISO would "no longer be permitted to recognize an incumbent's right of first refusal" and would treat the law as void.

But the 7th Circuit said incumbents taking advantage of their right to first dibs on construction only file notices of intent and descriptions of construction with the state regulatory body, noting that they don't ask permission.

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Furthermore, the court said a preliminary injunction of a state law "does not change the applicability of the law in question to non-parties."

MISO, meanwhile, has no intention of competitively bidding the Indiana share of its long-range transmission projects.

In an amicus brief in the case, MISO said it did not view itself as bound by the injunction, even though its tariff requires it to follow all applicable state laws. The RTO said the district court's preliminary injunction "does not direct MISO to take any action, nor does it prohibit MISO from taking any action."

The court agreed and said because LS Power named Indiana commissioners as defendants and failed to mention MISO in its request for injunctive relief, the company ensured the lower court "could not operate against MISO directly."

LS Power has attempted to close that gap through FERC. The company in February filed a complaint against MISO, arguing the grid operator should be forced to obey preliminary injunctions of state laws and should open about $1 billion in new long-range transmission projects in Indiana for competitive solicitation. (See *LS Power Files Complaint Against MISO over Indiana ROFR*.)

The apparent uncertainty over the IURC's authority drew a dissenting opinion from Circuit Judge Michael Scudder, who argued that ROFR enforcement can be traced to Indiana regulators. Scudder said Indiana law provides "every indication" that IURC has the power to prevent an incumbent transmission owner from building and operating a transmission project in the state.

"Everyone agrees that the commission is the regulatory agency with authority over public utilities in Indiana," he wrote. "Everyone agrees that HEA 1420 is a law 'relating to public utilities.' … It defies belief that the Indiana General Assembly vested the commission with broad enforcement authority, but the commissioners are nevertheless powerless to impose any limitation on a utility company's ability to construct, own, operate or maintain electric transmission facilities within the state. To adopt that view is to conclude that Indiana law does not mean what it says."

Scudder said he would have affirmed the district court's preliminary injunction.

But the 7th Circuit's majority agreed that ordering the IURC to block construction of interstate, MISO-approved transmission lines "would force the IURC into a power struggle with FERC over whether legitimately assigned and important projects" could be built.

"The dissenting opinion would in effect conscript the IURC to enforce the dormant commerce clause rather than carry out its more general duties to enforce Indiana public utility laws," the court said. ■

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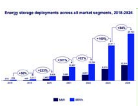
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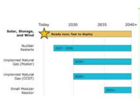
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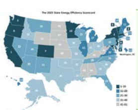
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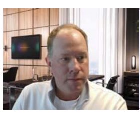
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Winter Fuel Constraints Concerning for NYISO

By Vincent Gabrielle

While NYISO operated reliably last winter, the season provided "continued examples of limited flexibility on the gas system," ISO staff told the Operating Committee on March 20.

Temperatures were below average last winter, but there was no need for emergency operations, Aaron Markham, NYISO vice president of operations, said in presenting the cold weather operations *report*.

There were 16 daily peak loads in excess of 22,000 MW, the most since the 2017/18 winter, with the peak load of the season occurring on Jan. 22 at 23,521 MW. NYISO's record is 25,738 MW, set Jan. 7, 2014.

The peak occurred during a cold snap that began over the Martin Luther King Jr. Day weekend. When the peak load occurred during the 6 p.m. hour Jan. 22, about 18% of the fuel mix was natural gas and 27% was oil. Markham indicated that this, and the high rate of oil consumption over the coldest days, showed that there were problems with gas procurement, leading to stored oil use.

"We did see some larger non-firm gas units actually put in derates during the Martin Luther King weekend as a result of a forecasted inability to get gas in response to the day-ahead schedule," said Markham. "I don't think we've actually seen that before, so that was kind of noteworthy."

Markham said that the average forced outage rate was higher than average during the winter. It was a challenge to manage unavailable capacity in gas units between the day-ahead and real-time because gas generators did not have their normal operational flexibility. Many dual-fuel units resorted to oil, leading to depleted oil reserves statewide.

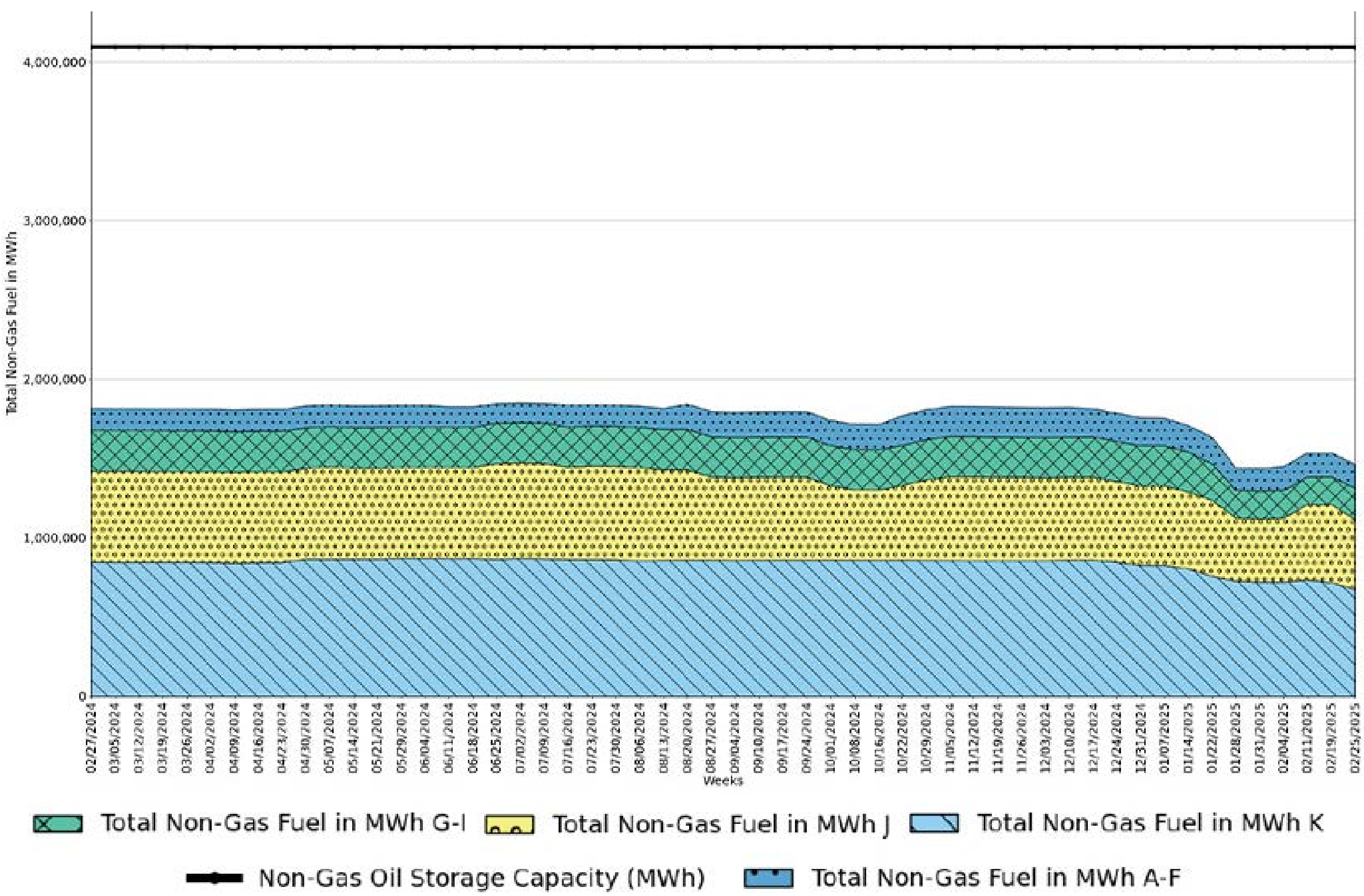
February Operations Report

Markham also presented the operations report for *February*.

While the month was milder than January, cold weather produced a peak load of 22,651 MW on Feb. 18. Toward the end of the month, Markam said there was a forced outage in the Greenwood/Staten Island load pocket in New York City caused by a transformer coming out of service while another parallel circuit was also out. NYISO implemented a targeted demand response program in the area.

Markham also mentioned that NYISO had found the source of curtailments of wind and solar resources in New York's southern tier. A circuit breaker at a substation in Union was "stuck," affecting several other lines nearby.

"We were able to work with the transmission owner to implement a strategy to avoid the stuck breaker contingency," said Markham, who went on to say that the ISO was evaluating whether their solution met the criteria for a facility to be *secured* in its market models. ■



| NYISO

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NYISO Business Issues Committee OKs Firm Fuel Accreditation Concept

By Vincent Gabrielle

The NYISO Business Issues Committee has approved, in concept, implementation of the ISO's new *firm fuel* election process and requirements as part of its changes to capacity accreditation.

The March 18 vote passed unanimously, with only the Market Monitoring Unit and Natural Resources Defense Council abstaining. The Installed Capacity Working Group will vote on revised tariff language before the Management Committee's March 26 meeting. The ISO aims for a FERC filing in mid-April.

For several weeks and across multiple working group meetings, NYISO stakeholders have been hammering out the details of the ISO's firm fuel accreditation improvement project. The project aims to ensure generators that say they have guaranteed (firm) sources of fuel deliver on their promises during winter months.

The ISO and the New York State Reliability Council are concerned about future fuel supply constraints in the winter. As New York transitions to a winter-peaking system, the downstate gas turbine fleet will find itself competing with home heating for fuel during peak periods.

FERC accepted NYISO's capacity accreditation changes in July 2024, but it delayed implementation until 2026 after generators complained of the limited amount of time to make their firm fuel elections: The changes required them to tell the ISO by Aug. 1 prior to each capability year how much of their capacity was covered by firm fuel supply. (See *FERC Accepts NYISO Capacity Accreditation Changes, with 1-Year Delay*.)

Why This Matters

Part of the effort to ensure winter reliability in a system transitioning to winter peaking, with increasing fuel constraints, is developing a 'firm fuel' capacity accreditation method.

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

Other requirements include that resources with firm fuel have supply, transportation and replenishment strategies in place by Dec. 1 of the capability year through the end of winter, and have fuel available to run 56 hours over any consecutive seven-day period in December through February.

Firm suppliers would not have to submit additional attestation that they have secured fuel, and those downstate and in Long Island would get their own capacity accreditation factor. Failure to meet firm fuel performance obligations by being unavailable because of fuel supply issues on the day-ahead or real-time markets could result in audit and financial sanction. The MMU also may examine suppliers if it identifies concerns with bidding or operational behavior.

Generators would be sanctioned based on the reason that the firm supply was unavailable, with a 1.5 multiplier added to violators who otherwise could have prevented it; NYISO would use NERC's guidance for "outside management control" events for the base "1.0" sanction.

During the ICAP Working Group's meeting the day before the BIC's vote, stakeholders wondered whether firm generators could be subject to sanctions if they were told by the ISO they were not being scheduled on the day-ahead market, sold their fuel and then were called on as part of the supplemental resource evaluation program but were unable to respond.

Responding to this concern during the BIC meeting, Zach Smith, senior manager of capacity and new resource integration for NYISO, clarified that gas-only firm units called in for SREs that don't respond would be evaluated only to see if fuel was available or if they made efforts to procure fuel.

"If there was no fuel available and they made those efforts to try and find it, they

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will not be subject to any penalty for the firm fuel," Smith said. "If our investigation finds that the fuel was procurable at a price and the entity did not try to get it, they will be subject to the 1.5 penalty."

Other stakeholders brought up the 16-month period between the firm fuel election (Aug. 1 prior to the capability year) and the deadline for having supply arrangements in place (Dec. 1 of the capability year). They argued this could lead to situations where a generator elects as firm but its fuel supplier "goes bankrupt" or experiences some other disruption and no longer can meet a firm fuel obligation. Stakeholders asked whether the eventual tariff revisions would include making generators tell the ISO if this occurred by the Dec. 1 deadline.

Nikolai Tubbs, a market design specialist for NYISO, said the ISO was going include that provision in the procedures manual, not the tariff.

Doreen Saia, chair of Greenburg Traurig's energy and natural resources practice, asked whether every financial penalty should be called a sanction. She said the effect of the 1.0 modifier was to put the generator in the position of not having the financial benefit of being a firm supplier, which wasn't really a sanction.

"That's not a sanction to me; that's an adjustment," Saia said. "I think we have to step back from calling it a sanction because [issues outside of a generator's control are treated] no different than the EFORd [equivalent forced outage rate on demand] rules we have today. I don't get an EFORd hit if the transmission line to my facility goes down."

Saia said she agreed with penalizing poor performers but that clarifying the punitive sanction from the non-punitive was necessary so future tariff revisions would be legible. "I guarantee you, six months from now when someone else is looking at this who has not been part of these conversations, they're not going to get it."

Smith said NYISO still was considering whether to use the word "adjustment" or something else. He said the ISO understood her concern and was working on it.

Market Monitor Proposes Future Firm Fuel Election Changes

Dovetailing off the firm fuel discussion at the ICAP Working Group meeting, MMU Potomac Economics proposed changes it said would better *coordinate the capacity market with firm fuel elections*.

The Monitor argued there were several issues with the current structure of firm fuel elections and how they interact with the Installed Reserve Margin study and fuel constraints. At the heart of its concerns is that generators make firm fuel elections roughly 15 months before the winter performance period they are electing for and that these elections cannot be changed. This pushes into a system where the IRM, capacity accreditation factors (CAFs) and unforced capacity prices are all interrelated.

"What we are saying is that there's a lack of market responsiveness," Potomac's Joe Coscia said. "We're setting the same price regardless of whether there's more or less fuel relative to the IRM requirement."

Coscia said the current system caused problems whether or not firm fuel elections were used in future IRM studies. If they were, generators could over-elect and incur financial losses or under-elect and artificially boost prices. This could increase the volatility of prices and CAFs. If they weren't used in the IRM, then the market and IRM might not be reflective of actual fuel arrangements.

"The resource adequacy modeling component should consider how to coordinate these fuel elections in a way that makes sense," Coscia said. "If you meet the requirements, consumers benefit from it."

Potomac proposed moving the firm election deadline to after the final CAFs are published and setting the winter UCAP requirements to satisfy the reliability criteria of the IRM study. This would mean that generators' firm fuel elections affect the amount of UCAP supplied relative to the reliability requirements, and they would be closer to when generators are sure of having contracts in place, knowing the price of fuel and the price of CAFs.

The Monitor said that while these changes will not be in place for the 2026/27 capability year, NYISO should discuss implementing them in the long term. ■

PJM Stakeholders Endorse Proposals to Rework ELCC Accreditation

Generation Owners Have Cited Risks Caused by Volatile Ratings

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM's Markets and Reliability Committee endorsed two proposals to revise the RTO's effective load carrying capability (ELCC) formula to add two new generation categories and limit the penalties resources face if their accreditation declines between a Base Residual Auction (BRA) and Incremental Auction (IA).

The volatility of unit ratings after auctions has been a sticking point for generation owners, who say it is unfair to commit a resource in the auction only to reduce that unit's accredited capacity (AUCAP) afterward.

And particularly so when ELCC ratings are falling due to changes in load forecasts, they argued.

The endorsed proposal, Package C, would limit the deficiency rate for a resource that has its rating reduced after being committed in the BRA to 100% of the clearing price, rather than the 120% penalty rate. Resources could still be subject to the penalty rate if they cannot meet their committed capacity because their installed capacity (ICAP) declined, such as due to unit failure, or if a planned unit does not come online according to schedule.

The proposal passed with 80% sector-weighted support, after an initial vote narrowly missed the two-thirds threshold at 66.08%.

Why This Matters

The volatility of unit ratings after auctions has been a sticking point for generation owners, who say it is unfair to commit a resource in the auction only to reduce that unit's accredited capacity afterward.

Pat Bruno, PJM | © *RTO Insider*

PJM's Pat Bruno said the proposal would retain an incentive for market sellers to avoid the deficiency by procuring additional capacity through bilateral transactions or in the IA without subjecting them to a penalty rate. Resources would also be held to their original commitment during a performance assessment interval (PAI).

He gave the example of a resource with 100 MW of ICAP that is committed at 90 MW in the BRA. If its AUCAP were to fall to 80 MW in an IA, it would be assessed a 10-MW deficiency charge at the clearing price unless it procures additional capacity. If that unit were to output at 80 MW during a PAI, without having procured capacity to make up the shortfall, it would be assessed a 10-MW nonperformance charge.

The main motion, Package B, would have frozen resources' ELCC ratings and AUCAP at the values used in the BRA. While resource ratings would not be changed, PJM would continue to update the installed reserve margin (IRM) and forecast pool requirement (FPR) values, necessitating that PJM modify its capacity buy/sell offers to work around any changes in accreditation.

The proposal was rejected by the MRC with 55% support. The two packages were nearly tied in a poll at the ELCC Senior Task Force (ELCCSTF), with Package B holding 66.5158% support and 68% preference over the status quo, while Package C received 66.5025% and 74.9% preference.

Load-serving entities, consumer advocates and Independent Market Monitor Joe Bowring argued that would shift all the risk of changing ratings to load, whereas Package C would more equitably split the risk between market sellers and buyers. Bowring said he opposed both options because they would inappropriately shift risk from generators to load.

Bowring said it shouldn't be any surprise that ratings can change between BRAs and IAs — it happened with the prior EFORd model as well, but ELCC is more volatile. The difference with both proposals, he argues, is they would inappropriately shift some or all of that risk to load, when it should remain with market sellers, who are capable of mitigating their risk by maintaining high performance when called upon.

'Emblematic' Debate

Several market sellers questioned Bowring and PJM on whether they can adjust their offers to reflect the risk of their ratings changing after an auction, noting that under EFORd, they were able to vary the amount of capacity they offered within a band defined by their annual and 5-year average forced outage values. Bruno responded that the ELCCSTF discussed whether that risk could be included in sellers' capacity performance quantifiable risk (CPQR) values, but that did not make it into the proposal.

Vitol's Jason Barker questioned whether generators can mitigate the risk by ensuring their units perform well because the class-based approach to accreditation means even a unit with perfect output when called upon can have its rating impacted by similar resources.

Barker also questioned PJM's ability to identify whether changes in ELCC ratings stem from resource performance or a change in the load forecast. He suggested PJM should procure more capacity if the demand side is responsible for the increased risk but should reduce ratings if sellers are driving the risk.

"This debate is emblematic of problems with ELCC," Barker said, adding it is creating unfair outcomes for either load or sellers no matter which approach is selected.

Bowring responded that a unit-specific ELCC approach would address the class average issue and said the Market Monitor has supported a unit-specific approach from the start of ELCC.

"This discussion further illustrates that PJM's ELCC approach needs significant improvements," he said.

Bruno said PJM previously explored but found it could lead to convoluted outcomes, such as scenarios where seasonal risk shifts toward the summer while the ratings for solar units decline.

Calpine's David "Scarp" Scarpignato said the implications of the proposals are very different when auctions are being held a year in advance with only one IA, versus the standard three-year, three-IA cadence. In the latter, he said there is more opportunity for large changes in the load forecast or a PAI, causing significant shifts in ELCC ratings.

The proposal to add new resource classes would establish oil combustion turbines (CTs) as their own bucket, organizing them from the miscellaneous "other unlimited resource" category, and breaking waste-to-energy as its own class from "steam."

Bruno said PJM ran a sensitivity based on the 2025/26 IA and found waste-to-energy would have an 83% ELCC rating, while oil CTs would be around 85%. Since there is a relatively small amount of capacity offered by waste-to-energy, pulling it out is expected to have little impact on the steam class. Other unlimited resources have unit-specific analysis, so combining their ratings is expected to have minimal impact.

Bruno told *RTO Insider* that grouping oil CTs together as a class better captures correlated outages and increases the amount of performance data available for modeling a particular unit. Since there is a limited number of PAIs from which to draw performance modeling, he said grouping units can smooth the impact of outages that happen at a consistent rate across that class. ■

PJM Presents Settlement on Site Control Requirements

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM on March 19 presented the Markets and Reliability Committee with a proposed settlement with several clean energy associations and developers on its site control requirements for new generation projects (*ER25-1544, EL25-22*).

Filed with the commission March 10, the proposed tariff revisions would codify a set of rules on when developers may add or remove parcels from a project that is less restrictive than the reading PJM has advanced in its Order 2023 compliance filing (ER24-2045). The settlement would resolve a complaint from American Clean Power Association, Solar Energy Industries Association and Advanced Energy United. It was also signed by EDF Renewables, which had raised issues with the compliance filing.

The language in the settlement would replace a PJM *proposal* to revise Manual 14H to codify its interpretation, which several developers throughout the stakeholder process have argued is overly onerous. The MRC voted by acclamation to defer action on the manual revisions until FERC action on the settlement or 60 days from its meeting, whichever is sooner. (See "Voting on Site Control Requirement Manual Revisions Deferred Pending Settlement," *PJM MRC/MC Briefs: Feb. 20, 2025*.)

PJM Director of Interconnection Planning Donnie Bielak said that if the settlement is approved, conforming revisions to the manual would be required. If it is rejected, he said the RTO's preference would be to pursue its originally proposed manual revisions.

Senior Engineer AJ Lambert said the key difference between the manual revisions and the settlement language is that in the latter, PJM would not require site control for parcels no longer needed for a project to be completed. It would also modify the decision point requirements and add clarification where there have been interpretation issues.

Changes to site plans would be permitted under the settlement so long as the developer can demonstrate there would be no impact to the "timing of milestones or transmission owner construction schedule." By making such a change, the developer would waive the ability to request milestone extensions "related to permits or other land issues."

Demonstration of site control over parcels no longer used on the site would not be required under the settlement. Any changes to interconnection facilities or switchyards would not be permitted if they would affect system impact or facilities studies.

The tariff currently requires that any changes to a project footprint be adjacent to the parcels included in the original project application, which would be expanded under the settlement to allow easements connecting parcels.

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Why This Matters

PJM has proposed tariff revisions that would change the site control requirements for projects in its queue to resolve a complaint by several clean energy groups.

PJM's proposed manual revisions have been deferred several times since being endorsed by the Planning Committee in December 2024, owing to the settlement negotiations. Discontent over the lack of insight into what was holding up consideration of the language led the MRC to initially vote against another deferral in February, but it reconsidered after PJM and EDF said they were confident that an agreement was imminent. (See "Stakeholders Endorse Quick-fix Revisions to Site Control Manual Requirements," *PJM PC/TEAC Briefs: Dec. 3, 2024*.)

The revisions would allow parcels to be added to a project at Decision Point 1 (DP1), so long as the land is adjacent to the site or evidence of connecting easements is provided. Parcels also could be removed at this point if the project continues to meet the minimum acreage and energy output defined in the project application.

While there would be no specific requirement to demonstrate site control at DP2, the proposed language would state, "Site control must be maintained throughout the cycle process." Adding parcels would also be permitted at DP2, with the caveat that a one-year term would be imposed from the end of Phase 2 of the relevant study cycle.

No additions would be permitted at the final DP3, but reductions would be allowed so long as the acreage-per-megawatt and evidentiary requirements continue to be met. Once a generator interconnection agreement is signed, any site control changes would require a necessary study agreement to determine permissibility. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse IRM and FPR for 2026/27 Capacity Auction

VALLEY FORGE, Pa. — The Markets and Reliability Committee endorsed by acclamation PJM's *recommended* installed reserve margin (IRM) and forecast pool requirement (FPR) values for the 2026/27 Base Residual Auction (BRA), with 40 load-serving entities and consumer advocates abstaining over what they called a lack of transparency into how the RTO arrived at the figures.

The IRM would increase to 19.1%, up from 17.8% in the 2025 Third Incremental Auction (IA), and the FPR would fall to 0.917 from 0.938. PJM's Patricio Rocha Garrido said almost all of the change is being driven by increasing demand in the load forecast, particularly in the winter. The seasonal balance of risk tilts to 65% loss-of-load expectation in the winter, increasing from 54.5% in the third IA; for the expected unserved entry metric, 93.9% of the risk would be in the winter.

The effective load-carrying capability ratings for most classes would also shift in line with increased winter risk. The rating for offshore wind would increase by 7%, to 69%, followed by onshore wind at a 3% increase, to 41%. In addition to having strong winter performance, Rocha Garrido said resources in the wind categories received transitional capacity interconnection rights (CIRs), which boosted the class's overall ratings.

Demand response resources would see their ratings fall by 8 points to 69%, while storage ratings would decline between 5 and 7% depending on the resource duration. Gas resources would see more modest drops, in part because of changes in class membership, while other thermals would be flat or fall by 1%.

Rocha Garrido said PJM ran a sensitivity using the 2025 resource portfolio and found there was minimal impact on ratings compared to 2026 expected resource mix, which he said supports the conclusion that most of the changing dynamics are being prompted by the load forecast. He explained that the reason there is more winter risk is because of extreme peak loads increasing in the 2025 forecast relative to 2024, while the summer peak loads are not growing relative to the 2024 forecast.

Scope of Deactivation Task Force Widened to Include RMR Agreements

Stakeholders endorsed charging the Deactivation Enhancement Senior Task Force with exploring the creation of a *pro forma* reliability-must-run agreement.

The MRC endorsed the change with 85% support, followed by the Members Committee endorsing by acclamation the same day. (See "PJM Presents Changes to DESTF Issue Charge," *PJM PC/TEAC Briefs: March 4, 2025*.)

The *revisions* to the task force's issue charge add a new key work activity (KWA) to draft a pro forma arrangement that recognizes the possible resource adequacy that RMR units can contribute and be effective for the 2028/29 delivery year. That year is when a temporary tariff provision allowing PJM to model the output of some RMR resources as capacity is set to expire (ER25-682). (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

The new language also expands the scope of the issue charge to allow consideration of a pro forma RMR agreement and changes to the capacity market rules around generators that have requested deactivation but which PJM has determined are necessary to maintain reliability. The out-of-scope section was also revised to carve out the new KWA.

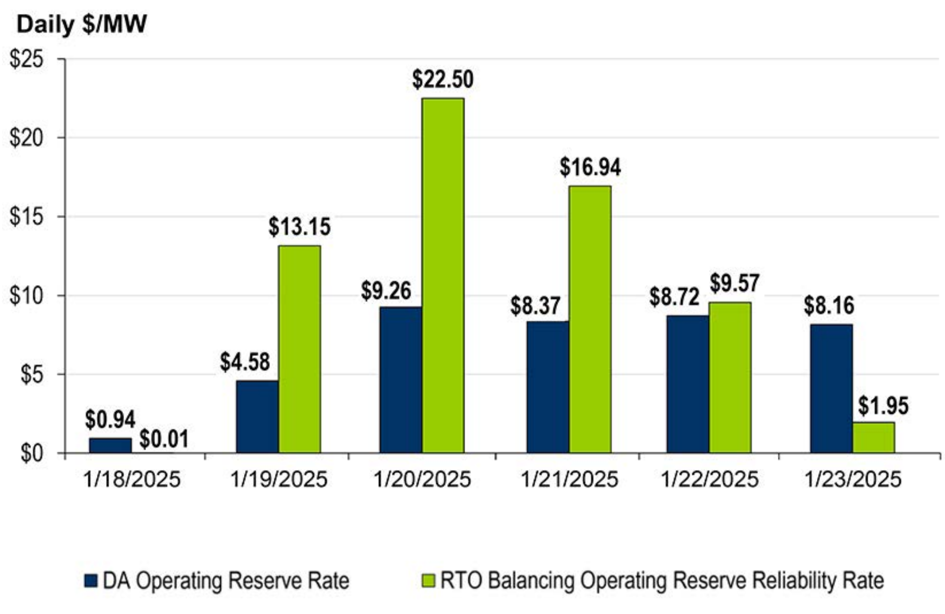
Several generation owners noted PJM's target of submitting a proposal to FERC around the end of the year would prevent changes to how RMR resources interact with the capacity market from being considered in the Quadrennial Review, which is in its early stages at the Market Implementation Committee.

Vistra's Erik Heinle said each RMR resource is unique and any pro forma agreement should retain the ability for a generation owner to pursue a cost-of-service rate at FERC. He suggested including language in the issue charge stating that owners of a deactivating unit can develop an agreement with PJM outside of the pro forma approach.

PJM Senior Counsel Chen Lu said he does not believe the proposed language would preclude that ability, adding it would be up to stakeholders to come up with rules that govern that.

Stakeholders Endorse Manual Language Expanding SIS

The committee endorsed *revisions* to Manual 14H implementing expanded eligibility for surplus interconnection service (SIS), reflecting tariff changes FERC



Uplift costs during a winter storm over the 2025 MLK Day weekend | *PJM*

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approved in February. (See *FERC Approves PJM's One-time Fast-track Interconnection Process*.)

SIS allows generation owners with resources that are not using their full injection rights to co-locate additional resources at the same point-of-interconnection, so long as the host resource's CIRs are not exceeded and no network upgrades are triggered.

The new language eliminates categorical restrictions on what resources — battery storage in particular — are eligible for SIS; changes how PJM models projects proceeding through SIS alongside those in the general interconnection queue; expands eligibility to applications where the host generator is still in development; and allows projects that consume transmission headroom but do not require network upgrades. It would also allow projects that require additional interconnection facilities for the service while still prohibiting new network upgrades.

Applications that could affect the network upgrades required for projects in the interconnection queue that have not had PJM determine if they will require upgrades would also no longer be prohibited from proceeding as SIS projects. The changes also eliminated language preventing SIS applications from proceeding if PJM has identified that the project would have a "material impact" on dynamic system stability response, steady-state thermal and voltage limits, or short-circuit capability limits.

The manual language was endorsed by the Planning Committee during its March 4 meeting. (See *PJM Stakeholders Approve SIS Manual Language*.)

PJM Presents 1st Read of Proposal to Rework Black Start Compensation

PJM's Glen Boyle *presented* a first read of a proposal to rework the base formula rate (BFR) used to compensate black start resources not carrying investment costs for providing the service.

The proposed tariff revisions were endorsed by the MIC during its March 5 meeting. (See *PJM Stakeholders Endorse Changes to Black Start Compensation*.)

The BFR includes numerous variables, including fixed and variable costs, training, fuel storage, and an incentive factor. The proposal would revise the fixed cost element to replace the zonal net cost of new entry (CONE) with a fixed value derived from the five-year RTO-wide CONE, which would thereafter be adjusted using the Handy-Whitman Index. Boyle said PJM does not see a correlation between net CONE and the need for black start resources, nor should there be a locational element to the price.

Boyle said PJM is concerned that if compensation for existing black start units is not increased, more resources will cease participation and they will have to be replaced on the more costly capital recovery factor (CRF), which is used to determine compensation for resources that require upgrades to provide black start. PJM is not proposing any changes to the CRF.

Since 2019 there have been 29 resources that stopped providing black start service, 26 of which were replaced through requests for proposals. All but two of the new black start units began providing the service on the CRF. Boyle said about 85% of the black start fleet is compensated through the BFR.

Independent Market Monitor Joe Bowring said there should be a focus on finding a way to compensate resources that fully considers their costs and ensures they see an appropriate return. He argued that the proposal, which was sponsored by PJM at the MIC, does not have a definition of an appropriate payment.

The Monitor's proposal, which did not win the MIC's support, would have used the RTO-wide net CONE, rather than zonal values, and included a recommendation that a more holistic stakeholder discussion be initiated to reconsider compensation.

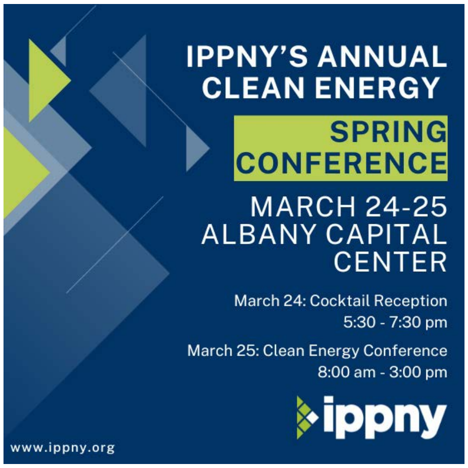
"This is simply refusing to address the underlying issue and making vague and unsupported allegations," Bowring said.

In previous meetings, Bowring noted that the process was instigated by the net CONE for future BRAs falling with the shift to a combined cycle turbine as the reference resource. FERC has since granted PJM's request to keep the reference resource as a combustion turbine.

Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said the advocates have been troubled by the lack of a metric to demonstrate the RTO's concerns that generation owners may be considering pulling their resources out of black start service.

Stakeholders Discuss Uplift Costs Seen During January Storms

PJM *presented* the impact winter storms during January had on uplift payments, which amounted to nearly $332 million between Jan. 19 and 23.



Storms falling on long holiday weekends have proven to be a challenge for PJM, as gas resources typically must purchase a package with a steady rate of fuel when nominating for supply on weekends and holidays. (See *PJM: 'Conservative Operations' Maintained Reliability During Jan. 2024 Storm*.)

Senior Dispatch Manager Kevin Hatch said the Martin Luther King Jr. Day weekend saw highly variable load across that weekend, which complicated efforts to block schedule gas, with the start of the weekend forecast to have fairly modest loads, ramping up to some of the highest winter peaks PJM has seen. Gas pipelines already had restrictions in place going into the weekend, and there was uncertainty about whether resources connected to those pipelines would be able to get fuel on the spot market.

PJM also had some resources start ahead of time so that any equipment failures associated with start-ups could be resolved before the storms rolled in. Once those units were online, Hatch said operators sought to avoid cycling them on and off throughout the storm to ensure they could remain available.

The RTO employed a new conservative operations procedure established after December 2022's Winter Storm Elliott, allowing operators to commit resources in advance when they believe those units could have difficulty procuring fuel or otherwise are at risk of not being able available. Several stakeholders have argued that the practice violates market principles and significantly increased uplift costs.

The majority of the uplift was balancing operating reserve credits, amounting to \$206 million, while day-ahead operating reserve credits accounted for an additional \$126 million.

In addition to impacts on the energy market, the amount of uplift paid during the January storm had a notable effect on the net CONE aspect of the capacity market, said Adrien Ford, director of wholesale market development for Constellation Energy.

"This is not acceptable to continue on the path that we're on," she said. "I'd like to note that this tie in is not just energy and uplift … but also net CONE."

Members Committee

Stakeholders Endorse Changes to MC Webinar Scope

The MC endorsed reducing the number of reports delivered to the committee via the webinars held between its face-to-face meetings.

The *revisions* to Manual 34 were advanced by Calpine and seconded by Vistra in an effort to move substantive discussions to venues that are attended by a wider spectrum of PJM's membership. (See "Manual Revisions Seek to Reimagine Role of MC Webinar," *PJM MRC/MC Briefs: Feb. 20, 2025*.)

Vistra's Heinle said the March 17 webinar included a fervent discussion about how load bids in the day-ahead market. He argued it would have been beneficial for more participants to have been involved in it.

The language also shifts PJM's regulatory, system and market operations reports to the MC, along with reports delivered by the Monitor and the Organization of PJM States Inc. Interregional coordination reports would be moved to the MIC.

The changes would also move the timing of the webinars to be held on the week following MC meetings, with the possibility of it being canceled if there is little to discuss. Currently it is held on the Monday before the committee meets. ■

— Devin Leith-Yessian

FERC Approves Tariff for SPP RTO West

Commission's Order Gives Grid Operator 2 Western Markets

By Tom Kleckner

FERC has accepted SPP's proposed revisions to its tariff that will incorporate seven Western Interconnection entities as transmission-owning members of the RTO, making the grid operator the first to provide full market services in the grid's two major interconnections.

The commission on March 20 directed SPP to make a compliance filing within 30 days. It also required the RTO to provide a notification of the RTO West's go-live date no later than six months prior (*ER24-2184*).

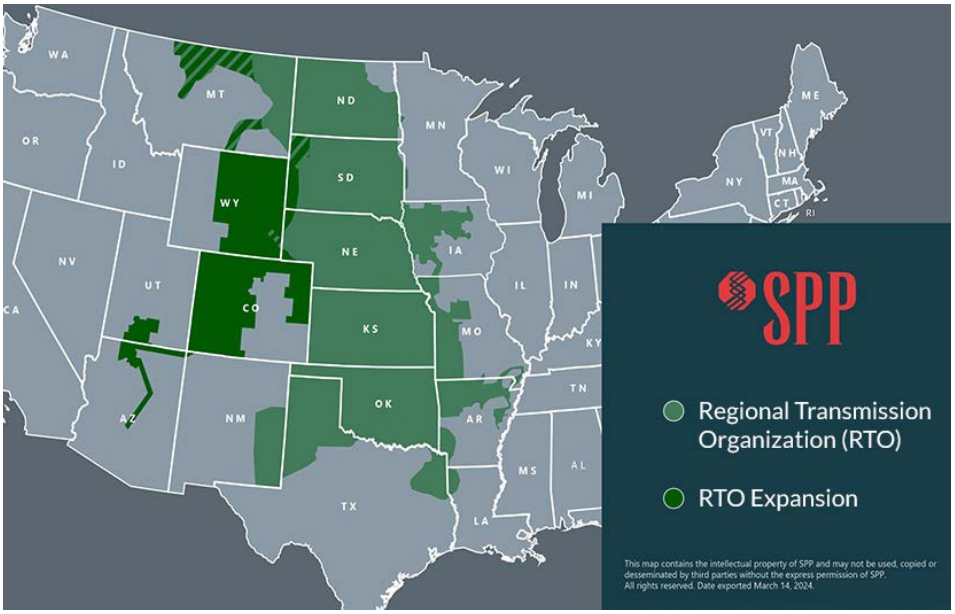
SPP has targeted April 2026 as when the entities will begin participating in its Integrated Marketplace, transmission planning, reliability coordination and other RTO services. They all are members of the *Western Energy Imbalance Service* market, which SPP has administered since 2021:

- Basin Electric Power Cooperative
- Colorado Springs Utilities
- Deseret Power Electric Cooperative
- Municipal Energy Agency of Nebraska
- Platte River Power Authority
- Tri-State Generation and Transmission Association
- Western Area Power Administration's Colorado River Storage Project, Rocky Mountain and Upper Great Plains regions

FERC agreed with the grid operator that its proposal to integrate the expansion members into its RTO likely will improve grid reliability and operational efficiency,

Why This Matters

FERC's acceptance of SPP's tariff revisions for its RTO West means SPP will be the first grid operator to provide full market services in both the Western and Eastern Interconnections.



SPP's RTO footprint will touch 17 states with its expansion into the West. | *SPP*

benefiting existing members and new ones. SPP has said RTO West will provide more than $200 million in annual benefits to its members, primarily through the optimization of DC ties with the Eastern Interconnection. (See *SPP Files to Incorporate Western Entities into RTO*.)

"The RTO West proposal will consolidate the management of transmission facilities under a single, centrally cleared market and allow SPP to dispatch resources more efficiently across a broader geographic area," FERC said.

"Expanding the RTO into the Western Interconnection is an exciting step in SPP's growth, bringing value to new and existing members while enhancing reliability in both interconnections," CEO Barbara Sugg said in a *news release*.

The commission filed a deficiency letter in October after SPP's first tariff filing and asked for further clarifications on six issues, including the optimization of DC ties. (See *FERC Issues Deficiency Letter for SPP's RTO West Tariff*.)

It said the RTO's proposed DC tie access and incremental market efficiency use charges are reasonable given the "unique role that the West DC ties will play" in connecting SPP's Western and Eastern balancing area authorities and the increased costs that will result from the ties' use in market dispatch.

"Absent these charges, these increased costs would be borne fully by customers in the West DC ties' transmission pricing zones because the [annual transmission revenue requirement] for each West DC tie will continue to be recovered from its respective transmission owner's zone," the commissioners wrote.

SPP said it is working with additional Western utilities that have expressed interest in becoming RTO members once this initial expansion is complete.

The grid operator is developing a second Western market in Markets+, a day-ahead offering centered primarily on the Pacific Northwest that secured FERC approval in January. It also serves as the program administrator for the Western Power Pool's Western Resource Adequacy Program. (See *SPP Markets+ Tariff Wins FERC Approval*.)

"Multiple markets maximize value for all participants," Sugg said.

The grid operator has expanded its footprint in the Eastern Interconnection from eight to 14 states since it became an RTO in 2004. The Western expansion will increase its service territory to all or part of 17 states.

The RTO's expansion is part of the grid operator's five-year strategic plan, *Aspire 2026*. ■

FERC Accepts SPP Revisions to TCR Market, Maintains Show Cause

Rehearing Request on RAR Rejected

By Tom Kleckner

FERC on March 20 accepted SPP's proposed tariff revisions incorporating a mark-to-auction (MTA) collateral requirement for its transmission congestion rights (TCR) market while stopping short of terminating a show-cause proceeding dating back to 2022 (*ER24-2906*).

SPP had requested that the commission terminate the ongoing show-cause proceeding (*EL22-65*) as part of its proposal, but FERC declined. It said that while the RTO's proposal included just and reasonable reforms to allow for the re-marking of monthly TCRs acquired in the annual auction, "it does not fully address the commission's concern that SPP's TCR collateral requirements may not adequately address the increased risk of default that results from a TCR portfolio that declines in value."

It further explained that seasonal TCRs — emphasizing the difference with monthly TCRs — would not be re-marked based on clearing prices in subsequent TCR auctions.

"Thus, the associated collateral requirements do not reflect a possible decline in value of those seasonal TCR products. Accordingly, SPP must still respond to the directives in the 2023 show-cause order," the commission said, referring to an earlier ruling that the RTO's tariff didn't include an MTA requirement or comparable alternative. (See *FERC Rebuffs PJM, SPP on FTR Credit Rules*.)

SPP said it re-evaluated whether an MTA could be developed in its TCR market to address FERC's concerns over the use of historical price data to calculate collateral requirements. It said the proposed revisions would mitigate a TCR portfolio's risk of declining in value over time by implementing more frequent updating of collateral requirements based on valuations from more recent TCR auctions.

Why This Matters

FERC found that SPP's revisions, while just and reasonable on their own, did not address its concerns dating back to 2022 about the RTO's TCR market.

The RTO said the changes proposed in protests by DC Energy and the Energy Trading Institute would require "nothing short of a complete TCR market redesign." SPP's Market Monitoring Unit originally intervened in support of the grid operator but later said the proposal did not appear to be consistent with the commission's show-cause order.

FERC granted SPP's request for waiver of the commission's 120-day notice requirement for good cause shown and accepted the proposed tariff revisions effective May 1.

MMU Doesn't Get Rehearing

In a separate order, FERC rejected the MMU's rehearing request of its acceptance of SPP's proposal to establish a winter season resource adequacy requirement (RAR) by modifying its order and sustaining the result (*ER24-2397*).

The MMU said the commission erred in its November 2024 order approving the RAR. It contended that FERC erred in finding that SPP does not study forced outages and violated the rule of reason by failing to require the inclusion of outage scheduling procedures in the RTO's tariff. The Monitor requested that FERC direct SPP to define "forced outage" in a compliance filing and to include its outage study procedures in the tariff at issue.

The commission said it was unpersuaded by the MMU's arguments. It said SPP's proposed language included the definition of an "authorized outage" that differentiated which resources can be counted toward a load-responsible entity's RAR from those that cannot. It said the RTO's outage coordination methodology makes clear that forced outages are those "forced" upon the SPP system,

GridLiance

as opposed to other outages that are studied and approved.

FERC also disagreed with the MMU that SPP provided insufficient detail related to the tariff's outage scheduling procedures to satisfy the rule of reason. It found that the RTO's proposed language does not need to include the outage study procedures and said the MMU's specific arguments pertaining to how SPP will study outages and whether the tariff contains sufficient detail on the procedures were beyond the scope of the proceeding.

The commission said it did not find that SPP's forced-outage definition "'significantly impacts rates' in such a manner that the rule of reason" would be included in the tariff. FERC noted that while it found the definition of "seasonal net peak load" in a separate SPP proceeding "significantly affects rates" because it had a direct impact on effective load-carrying capability values, "the relationship between how SPP will study outages and the final resulting rate is only relevant as to the" performance-based accreditation methodology. ■

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BPA Workshop Leaves Little Room to Probe Markets+ Decision

Meeting was 'Missed Opportunity' to Discuss Draft Day-ahead Policy, Critic Contends

By Robert Mullin

The Bonneville Power Administration's first day-ahead markets workshop since issuing the draft policy stating its intention to join SPP's Markets+ left little opportunity for critics to probe agency officials about the decision.

That's because the meeting featured a ground rule that largely checked inquiries from skeptics of the agency's choice: Discussion had to be limited to "clarifying questions" about only what's spelled out in the policy document.

"I want to be as clear as I can that these questions are really about the content that is in the draft policy, and it's about clarifying that content," Ashley Donahoo, BPA day-ahead markets lead, said at the start of the March 19 workshop, likely the last such meeting before the agency issues its final "record of decision" (ROD) in May. (See *BPA Selects SPP Markets+ in Draft Policy*.)

That instruction deviated from previous day-ahead workshops, where staff fielded a range of questions and took oral comments from participants on the fly. Instead, participants were instructed to reserve most questions for "formal" comments to be submitted to BPA through April 7.

"If I do say, 'We can't answer that question, you need to submit a formal comment,' I'm not trying to be rude. This just is not the forum for that," Donahoo said.

BPA offered its own clarification about the purpose of the meeting: "The workshop was intended to be an opportunity for stakeholders to ask clarifying questions on BPA's day-ahead market draft policy as they prepare to meet our April 7 comment deadline."

"This is a little bit challenging, this framework for the conversation," said Stefanie Johnson, a strategic adviser with Seattle City Light, a BPA "preference" customer that has criticized the agency's preference for Markets+. (See *Markets+ Leaning 'Alarming,' Seattle City Light Tells BPA*.)

Fred Heutte, senior policy associate at the Northwest Energy Coalition (NWEC), said the restriction meant a meeting scheduled for six hours lasted little more than two hours.


Fred Heutte, NWEC | © *RTO Insider*

What's Next

BPA's March 19 meeting likely was the last public day-ahead market participation workshop the agency will hold before issuing its final record of decision in May.

"Because it was limited only to 'questions of clarification,' the BPA day-ahead markets workshop was a missed opportunity for discussion of the broader themes of BPA's draft market policy," Heutte told RTO Insider.

Heutte's frustration should come as little surprise to anyone familiar with the position of his organization, which has long advocated for the creation of a single Western electricity market that pointedly includes CAISO and California. NWEC has strongly and repeatedly urged BPA to join CAISO's Extended Day-Ahead Market (EDAM) or at least postpone a decision until developments play out around the West-Wide Governance Pathways Initiative's efforts to bring more independent governance to EDAM and the Western Energy Imbalance Market (WEIM). (See *Pathways 'Step 2' Bill Sets Conditions for EDAM Governance.*)

"BPA's own study shows it would risk a net loss of $100 million a year or more by joining the smaller of the two market areas instead of staying in the WEIM, which has proven its value to all participating areas," he said, referring to the market benefits study consulting firm Energy and Environmental Economics conducted last year on behalf of the agency. (See *BPA Sticks to Markets+ Leaning Despite Study Showing EDAM Benefits*.)

Heutte was the most persistent questioner during the workshop. His first question dealt with a statement in the draft policy that acknowledged BPA still lacks enough information to assess what impact joining Markets+ will have on emissions attributed to federal power purchases from the agency.

"When will that information be available and incorporated into your analysis?" he asked.

BPA climate change specialist Alisa Kasewater said the agency would be unable to provide a "quantifiable number" on emissions impact until it gets closer to operating in the market because of continued uncertainties. Questions remain around the interaction of state-specific greenhouse gas (GHG) rules with the market's system for tracking and attribution of emissions, BPA's own asset-controlling supplier emissions factor and the makeup of resources participating in the new market.

Kasewater addressed Heutte's next question about what elements BPA prefers about the Markets+ GHG design. But Donahoo headed off his follow-up asking if BPA identified any preferable elements in EDAM's handling of GHGs.

"I just want to be careful, because we are asking for clarifying questions. In the draft policy, was there something that you wanted clarified that you saw in there about what we said specifically?" Donahoo asked.

'Fullness of Our Response'

Heutte elicited similar responses when he pressed BPA staff on other issues, including:

- How BPA is differentiating between the vendor relationship Markets+ will have with SPP and that between EDAM and the Pathways Initiative's proposed "regional organization."

Ashley Donahoo, BPA | © *RTO Insider*

- Given that SPP's Board of Directors will retain "ultimate authority" over the RTO's markets, "how much relative weight" in SPP management decisions will "Western interests" have compared with the broader SPP membership.
- Why BPA isn't waiting to see how this session of the California Legislature progresses on implementing the Pathways Initiative's governance bill for CAISO.

"I understand your comments, and I do think you need to submit them formally," Donahoo said. "I'm not hearing a clarification. I'm hearing more of a questioning of why we went our way."

"I'm not trying to be argumentative; I'm trying to raise issues that we would like to clarify," Heutte responded.

Speaking on behalf of the Northwest & Intermountain Power Producers Coalition (NIPPC), Henry Tilghman posed a question that referenced recent job cuts and resignations at BPA stemming from actions by the Trump administration. (See *BPA to Restore 89 'Probationary' Staff, Agency Confirms*.)

"I follow the news. I've talked to people at Bonneville. It sounds like you're resource constrained. Can Bonneville deliver on the timeline to implement a day-ahead market in 2028?" Tilghman asked.

"I don't believe we've mentioned 2028 in the draft policy, so I don't see that as a clarifying question, but I recommend that you submit your comment," Donahoo said. "And correct me if I'm wrong: DOE has restricted us from talking about staffing, so we can't add anything to that."

"I'm hearing a lot of mentions of, 'Submit comments. We'll address them,'" said Kalia Savage, principal transmission and markets policy analyst at Portland General Electric (PGE), which last year committed to joining EDAM.

"Since PGE has submitted comments throughout the process, we haven't had all of our comments addressed. And then with the policy decision going towards Markets+, I would love to hear how comments are actually going to be addressed and considered given the policy decision direction," she said.

Donahoo said BPA has posted on its website answers to any questions asked throughout the day-ahead market workshops, while comments on the draft policy will be addressed in the ROD.

"I'm quite sure in the fullness of our response, we will make a complete presentation of our views," Heutte said.

'Really Meaningful'

Still, BPA officials did address several stakeholder questions during the workshop, including some dealing with matters not explicitly spelled out in the draft policy.

In response to Tilghman's question about whether BPA's market analysis would be affected by delays in implementing the first binding season of the Western Resource Adequacy Program (WRAP), which Markets+ members are obligated to join, BPA's Matt Hayes said the agency thinks WRAP participants, the Western Power Pool and SPP are committed to making the program work.

Besides, Hayes noted, beginning the WRAP's binding period in winter 2027/28 technically doesn't constitute a "delay" because the timeline still falls within the requirements of the program's FERC-approved tariff.

Savage asked whether BPA would update its ROD after its May release based on developments coming out of the California legislature and CAISO's GHG Working Group and upcoming EDAM congestion revenue rights allocation initiative.

"At this time, the final policy would be based on the facts that exist at the time of publication," BPA attorney Erika Doot said. "If there were significant changes, we would consider whether we need to issue a subsequent document."

As the meeting wound down, Chris Roden, director of energy services at Clatskanie (Ore.) People's Utility District, sounded a supportive note for BPA.

"Reserving my opinion on where Bonneville is landing, I feel heard representing load — and also some independent generation — in the region," Roden said. "I appreciate the process — the diligence — Bonneville has gone through, both from a legal perspective and a technical perspective. And this final ability to comment is really meaningful."

"I recommend that you submit that formally. Thank you," Donahoo joked. ■

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SPP Study: $88B to $263B in Generation Needed by 2050

Brattle Group Says All Resources Contribute to Grid Reliability

By Tom Kleckner

A study of SPP's future energy and resource needs has found the grid operator will have to rely on thermal generation to maintain grid reliability into midcentury. It will come at a cost.

The Brattle Group's analysis says the RTO will require at least $88 billion and up to $263 billion of generation investment to support its load growth through 2050.

Much of that will be renewable energy. According to the study's five scenarios, SPP could add at least 62 GW of renewable capacity and as much as 180 GW by 2050. SPP's all-time demand peak is 53.2 GW, set in 2022.

"We can maintain the resource adequacy in a cost-effective and affordable way with all these new carbon-free resources in the system," said SPP's Afshin Salehian, who presented the study's results to a March 19 joint meeting of several stakeholder groups. "There is still a value for fossil fuel generation capacity. [It is] needed to maintain the resource adequacy requirements in the most challenging hours of the system, and there are definitely needs for [that] fossil fuel generation in the system."

Why This Matters

The study says renewable resources will account for much of the expected increase in generation by 2050, but thermal resources still will be necessary to maintain grid reliability.

In the study's scenarios with high load growth and high shares of renewable generation, SPP is projected to affordably maintain resource adequacy if fossil fuel generation capacity is retained or replaced and sufficient new resources, including storage, are added to the system.

The Future Energy and Resource Needs (FERNS) study found that conventional generation will continue to serve about 40 to 60% of the region's accredited capacity by 2050. However, renewable resources — aided by technology costs, natural gas prices and the availability of tax credits — will provide between 70 and 90% of the RTO's annual energy, according to the study.

Brattle said SPP generated 47% of its energy from carbon-free resources in 2024.

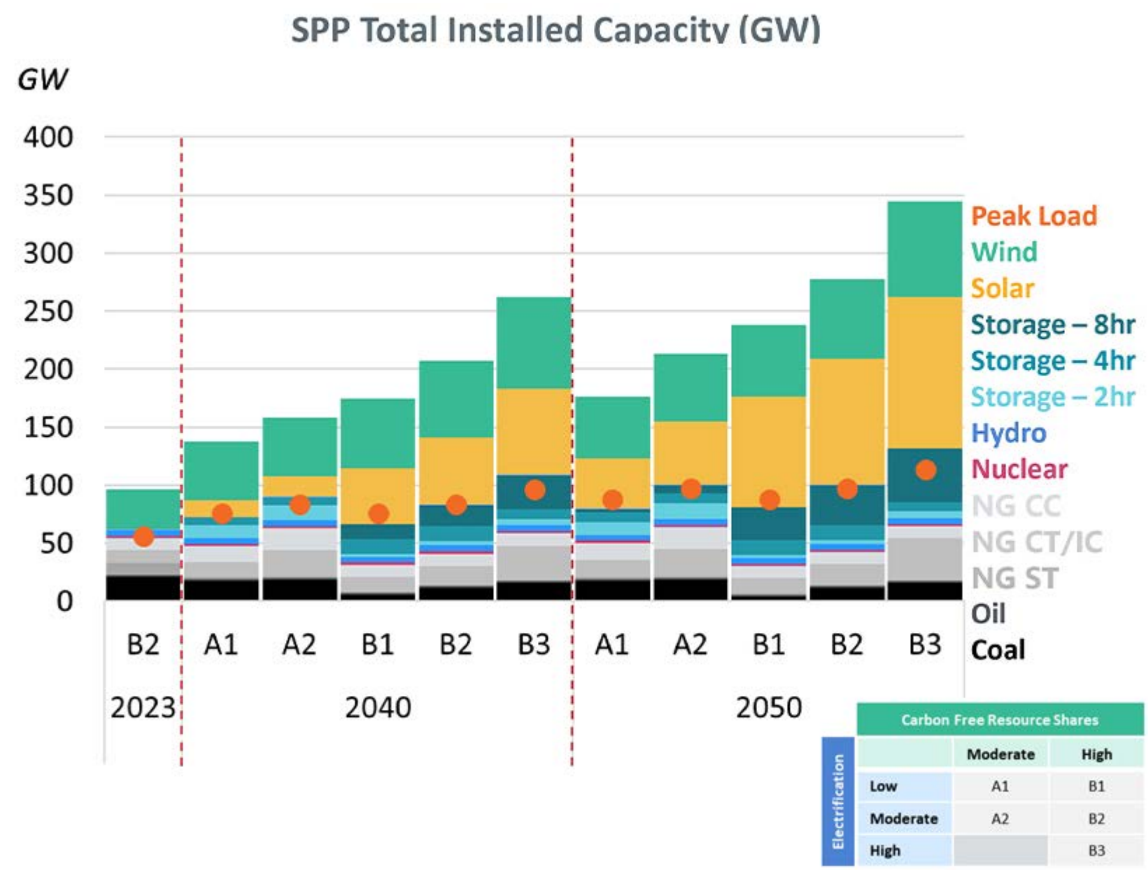
"There [are] still fossil fuel generations in the system. They are generating some amount of energy," Salehian said.

Simon Mahan, executive director of the Southern Renewable Energy Association, said the study highlights the importance of expanding transmission today and in the future.

"Just last week, wind energy resources were providing about 60% of SPP's electricity demand," he said, noting wind energy's 58.2% share of the fuel mix at 11 a.m. CT March 19.

"SPP's study demonstrates the need for additional transmission to help retain costs, maintain reliability and expand clean energy resources," Mahan added.

Indeed, the FERNS study found SPP will



SPP's future energy and resource needs could require 250% more capacity than the RTO has today. | *SPP* need between 4 and 21 GW of new transmission capacity in its pricing zones.

"This study was not a transmission planning study but as we were trying to meet the demand in different scenarios, we realized that it is cheaper to build transmission rather than meet the demand locally with local generation," Salehian said. "We had to build large-scale, long distance transmission lines to access higher-quality generation resources in other zones or in renewable-rich zones."

The FERNS study was designed to find the most cost-effective future resource mix to meet system needs through 2050 and determine how the operational and investment costs vary across the five scenarios. It also identified the current resource adequacy framework's shortcomings in a highly electrified and decarbonized future.

Brattle analyzed the change in SPP's generation mix from 2030 through 2050, its resource adequacy risks, and the transformation's cost, given the changes in supply and demand. It used a zonal capacity expansion model for each of the five FERNS scenarios and for recognizing interconnection with the RTO's neighbors.

The study also found that by 2050:

- Solar generation (between 42 and 130 GW) will outpace wind generation (between 20 and 48 GW). That also will require between 22 and 59 GW of battery storage, often co-located, to maintain resource adequacy.
- Winter planning reserve margins will need to be "significantly higher" than summer reserve margins because of low solar capacity values and high temperature-correlated fossil outages in the winter.
- There's enough available land in SPP's footprint to accommodate the additional projected wind and solar capacity in all scenarios evaluated.
- Effective load-carrying capability (ELCC) values for solar and short-duration storage resources are projected to decline over time, but wind resources' ELCC will increase slightly. That indicates a need for long-duration storage and interties with neighboring regions that offer resource adequacy and extreme-weather resilience benefits.
- The grid operator is expected to take advantage of its ample renewable generation and become a more significant net exporter to other regions.

The study began in 2024 and was coordinated with SPP staff and stakeholders. It was sponsored by the *Future Grid Strategy Advisory Group* (FGSAG) and endorsed by the Resource and Energy Adequacy Leadership Team.

The study itself is not yet available. Salehian will present the study's findings to the FGSAG on March 31 and again during the April 16-17 Strategic Planning Committee meeting. An SPP spokesperson said the final report will be published with the SPC meeting materials the week before. ■

Company Briefs

DOE Approves Venture Global to Export LNG to More Countries

The Department of Energy last week approved Venture Global to export LNG from its Cameron Parish facility to more countries.

The approval means Venture Global can export LNG from its Calcasieu Pass 2 project to any country, including Europe. Previously, the plant was limited to exporting to the 20 countries the U.S. has free trade agreements with, which includes nations such as Australia, Canada, Israel, Korea, Mexico and Singapore.

CP2 is expected to pump out about 20 million tons of LNG annually, which would make it the third-largest exporter in the nation.

More: *Nola.com*

OCI Holdings to Build 2-GW Solar Cell Plant in Texas

Korean chemical industries company OCI Holdings last week announced it will build a 2-GW solar cell production facility in Texas.

The company will invest $265 million in the plant that will initially produce 1 GW of cells annually before increasing to 2 GW in 2026.

More: *PV Tech*

RWE, Meta Sign PPA with Texas Solar Project

RWE and Meta last week announced a new power purchase agreement with a 200-MW solar project in Texas.

Under the agreement, Meta will purchase 100% of the output from RWE's Waterloo Solar project, which is set to begin construction in late 2025.

More: *RWE*

T1 Energy Reveals Site of New Solar Factory

T1 Energy, formerly FREYR Battery, has revealed that the location of its new U.S. solar cell factory will be in Milam County, Texas.

The $850 million facility will be a part of the Advanced Manufacturing and Logistix Campus at Sandow Lakes and will produce up to 5 GW of solar cells.

Construction of the factory, which is expected to be one of the largest solar manufacturing facilities in the U.S., is scheduled for mid-2025.

More: *Electrek*; *Houston Chronicle*

Federal Briefs

Judge Bars EPA from Taking Back $20B in Climate Grants — for Now

U.S. District Judge Tanya Chutkan last week temporarily blocked EPA's attempt to recoup $20 billion in Biden-era climate grants.

EPA "gave no legal justification for the termination" of the contracts, wrote Chutkan, saying the administration had only "vaguely" outlined its allegations that the grant program was marked by waste and potential conflicts of interest.

The ruling prevents EPA from reclaiming money it had deposited at Citibank for the groups Climate United, Coalition for Green Capital and Power Forward Communities. However, the decision did not revive those groups' ability to draw from the funds, postponing that decision until after further court proceedings.

More: *POLITICO*

EPA Has Canceled 49 Individual Grants Worth $230M

EPA has canceled or prevented 49 individual grants from being awarded from Jan. 20 through March 7, according to a document provided to the Sierra Club through the Freedom of Information Act.

The grants' total cumulative value is more than $230 million, although some $30 million appears to have already been paid out to recipients. Nearly half of the canceled grants are related to environmental justice initiatives, while nearly as many were funding research into lower-carbon construction materials and better product labeling to prevent greenwashing.

More: *Heatmap*

Sneed out at DOE's LPO

John Sneed, who returned to run the Department of Energy's Loan Programs Office in the second Trump administration in January, stepped down last week.

Sneed, who served as executive director of the office in the first Trump administration, was reappointed in a transitional capacity in January. The original contract was for 30 days, though the period was extended twice. However, almost exactly 60 days after President Donald Trump's inauguration, Sneed will return to Texas, the agency said.

The LPO didn't immediately announce who will replace Sneed.

More: *Latitude Media*

National/Federal news from our other channels

NERC Selects Berkshire's Michael Ball as E-ISAC CEO

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

State Briefs

ARKANSAS

Carroll County Bans New Commercial Wind, Solar Projects

Carroll County last week voted unanimously to enact a moratorium on the construction of new commercial wind and solar energy projects.

The moratorium would be in effect for five years after the Nimbus wind project begins operating. The project is currently in the earliest stages of construction. The company has been working on the project for years, and the county government cannot interfere with contracts that have already been signed.

More: *Arkansas Times*

'Construction Work in Progress' Bill Heads to Gov. Sanders

The state House of Representatives voted 77-13 to pass a "construction work in progress" bill that would allow utilities to finance projects during construction through a new rate increase rider.

The investments would still have to be approved by the Public Service Commission. The bill would raise rates by about $5 a month for the first year.

The bill now heads to Gov. Sarah Huckabee Sanders. If it is signed, it will take effect immediately.

More: *Northwest Arkansas Democrat Gazette*

CALIFORNIA

Newsom Accelerates Fresno County Solar Project

Gov. **Gavin Newsom** last week certified the 300-MW Cornucopia Hybrid Energy Project in Fresno County, meaning it can bypass legal challenges that often delay large projects.

Senate Bill 7, passed in 2021, allows the governor to certify clean energy projects under the California Environmental Quality Act.

Construction is expected to begin in late 2027, with operations beginning mid-2030.

More: *GV Wire*

SDG&E Cleared to Expand Imperial Valley Battery Site

The Public Utilities Commission has approved San Diego Gas & Electric's request to expand its existing battery facility in Imperial Valley to 231 MW.

SDG&E intends to install 100 MW of additional capacity to the 131-MW Westside Canal battery energy storage system.

The expanded site is expected to begin operations by June.

More: *Renewables Now*

CONNECTICUT

United Illuminating Cuts $70M in Investments

United Illuminating last week said it has cut nearly $70 million worth of investments in its statewide service territory because of the Public Utilities Regulatory Authority's decision to deny much of the utility's request for a rate increase in 2023.

The announcement came less than a week after a superior court judge dismissed most of the company's claims that PURA acted unfairly by denying its request for more than $100 million in additional revenues in its most recent rate case. A spokeswoman said the company has yet to determine whether it will appeal the decision.

Eversource made a similar announcement last year when it said it was cutting $500 million in investments as a result of its frustrations with PURA's regulatory approach.

More: *CT Mirror*

IDAHO

Idaho Power Agrees to $800K Valley Fire Settlement

Idaho Power has agreed to pay an $800,000 settlement to help the state restore winter wildlife habitat burned during October's Valley Fire.

The Legislature's Joint Finance-Appropriations Committee approved a one-time $800,000 appropriation to the Department of Fish and Games wildlife program to allow the department to accept the settlement money and spend it on restoring burned areas within the Boise River Wildlife Management Area.

The Valley Fire started Oct. 4 and burned 9,904 acres, including part of the Boise River Wildlife Management Area. A power line touching the ground was found responsible for starting the fire.

More: *Idaho Capital Sun*

LOUISIANA

Livingston Parish Extends Moratorium on Solar

The Livingston Parish Council unanimously voted to extend its moratorium on solar development through May 2026.

The ordinance extending the moratorium says the parish "is currently undertaking a study and considering new development rules, policies and ordinances concerning the innovative technology of commercial solar power and solar panel farms."

More: *WBRZ*

MICHIGAN

PSC Approves Consumers Energy Rate Hike

The Public Service Commission last week approved a $153.8 million rate increase for Consumers Energy.

The increase, which was less than half of what Consumers initially sought, will take effect in April. It will raise the average residential bill by $2.78 (2.79%) a month.

More: *MLive*

NEVADA

Reno Approves Data Center

An appeal for a second North Valleys data center was approved unanimously by the Reno City Council, which overturned the planning commission's original denial.

The Reno planning commission asked the council to hold off on approving more data centers last month until members could fully understand their effects. The council had the opportunity to change regulations in the codes for data centers, but the vote failed.

The commission had denied the Oppidan Data Center over concerns there weren't enough water or power resources available for the project. The data center is planning to use 8 acre-feet of water and 8 MW a year.

More: *Reno Gazette Journal*

NEW MEXICO

Forestry: Utility Line Caused Mogote Hill Fire

The Mogote Hill Fire that ignited March 14 was started by a utility line, according to investigators and a State Forestry spokesperson.

The grass fire ignited a little after noon amid dry conditions and high winds, prompting evacuation orders along a nearby state highway. It grew to about 33 square miles before being curtailed.

Forestry spokesperson George Ducker said he did not know who owned the line that sparked the blaze and referred the issue to the Mora County Sheriff's Office. Rural electrical co-ops own most of the lines in the area.

More: *Source NM*

OHIO

Senate Approves Measure Eliminating HB 6 Surcharge

The state Senate last week unanimously approved a measure that, among other things, eliminates the legacy generation rider — a surcharge devised to prop up two aging coal plants that are part of the Ohio Valley Electric Corporation.

The rider was part of 2019's House Bill 6, which was at the heart of a massive bribery scheme that landed former House Speaker Larry Householder in federal prison with a 20-year sentence. So far, the rider has cost ratepayers about half a billion dollars.

The proposal also encourages investment in new gas-fired power plants, as well as reducing the time for regulatory decisions.

More: *Ohio Capital Journal*

OREGON

Report Says PacifiCorp not Responsible for Santiam Fire

Department of Forestry investigators determined the 2020 Santiam Canyon fire was not caused by downed power lines as plaintiffs' attorneys have alleged but rather by hot embers drifting into the canyon from the nearby Beachie Creek fire.

The report, released to the Oregon Journalism Project under a public records request, is a victory for PacifiCorp, the embattled utility that in 2023 was found by a jury to have been grossly negligent in declining to shut off power to the fire.

"ODF investigators did not find any evidence that reported powerline ignitions had contributed to the overall spread of the fire in the Santiam Canyon," the report read. "The most probable explanation for these ignitions is spot fires from the main Beachie Creek Fire, which was burning upwind of the ignitions in the Santiam Canyon."

More: *Willamette Week*