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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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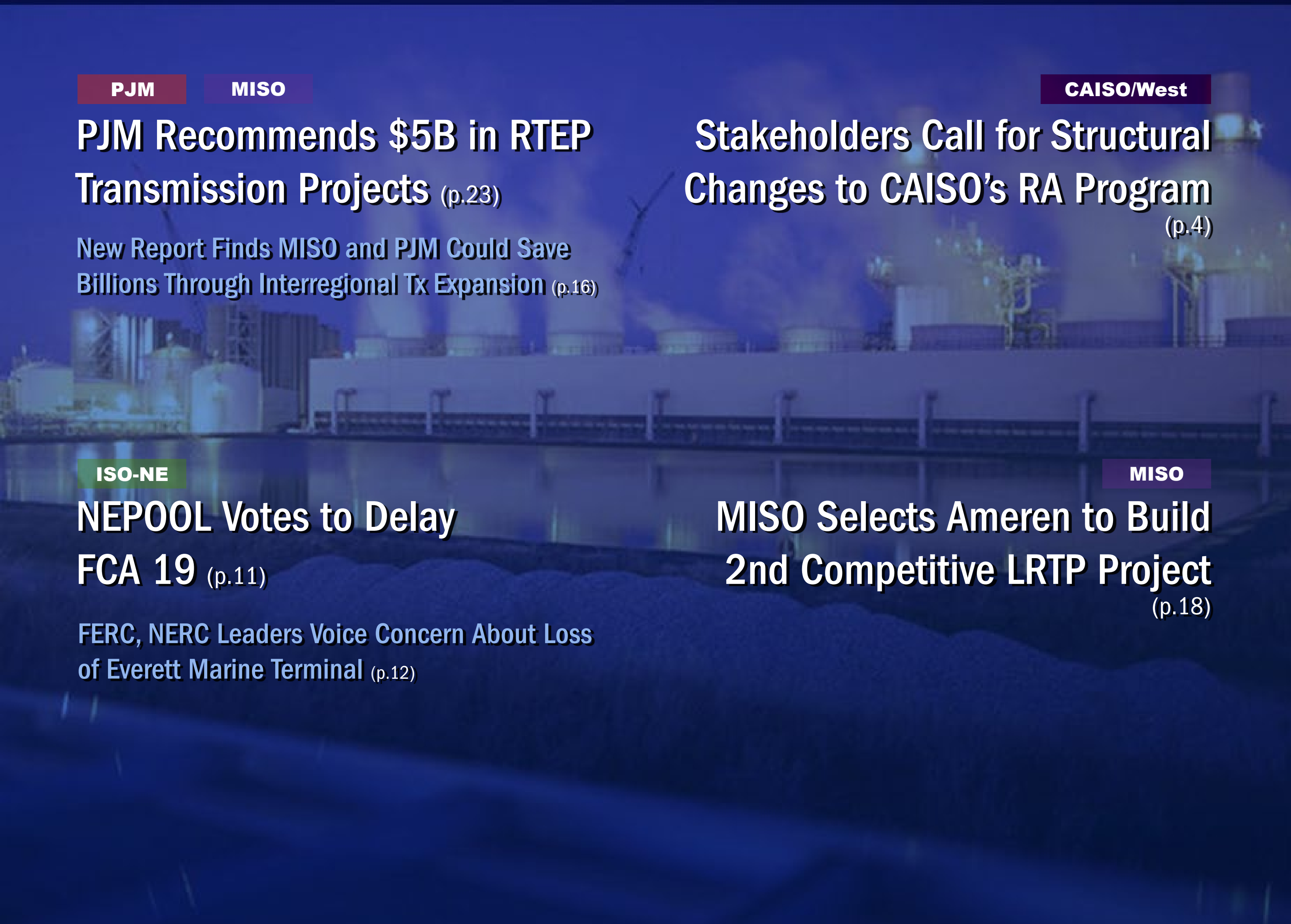

COVER: Proposition 7 would set aside billions for new gas plants in Texas. | *Fluor*

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Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

FERC/Federal News

FERC Environmental Justice Chief Explains Commission's Efforts

By James Downing

The National Association of Regulatory Utility Commissioners hosted a webinar last week with FERC Senior Counsel on Environmental Justice and Equity Conrad Bolston, who explained how the commission has been stepping up its work around environmental justice since 2021.

Bolston took over the role in March after Montina Cole, the first person with the job, left late last year. Working out of the Office of the General Counsel, Bolston leads a small team focused on the subject.

"My primary mission is to provide leadership and steer implementation of environmental justice and equity policies, principles, practices and procedures at the commission," he said.

Sometimes "Diversity, Equity and Inclusion" is conflated with environmental justice, but Bolston's work is focused on the latter exclusively.

"On a day-to-day [basis], that might mean assisting in reviewing and editing documents, from NEPA [National Environmental Policy Act] documents to orders, draft rules [and] policies, or holding trainings and outreach like the one we're having here today," he added.

Environmental justice has a number of definitions, but Bolston said it means ensuring that citizens are treated fairly regardless of their racial, economic and national backgrounds, or any other attributes when it comes to environmental regulation.

President Joe Biden in April issued *Executive Order 14096* on recommitting the U.S. to environmental justice, which it defines as "the just treatment and meaningful involvement of all people, regardless of income, race, color, national origin, tribal affiliation or disability in agency decision-making and other federal activities that affect human health and the environment."

The order explains the goal will be achieved when everyone enjoys the same degree of protection from environmental and health hazards, and equal access to the decision-making process.

As an independent agency, FERC has voluntarily complied with that and related executive orders, with both Chair Willie Phillips and his predecessor, Richard Glick, making it a priority, Bolston said. Under Glick, FERC released an equity action *plan*, which laid out its goals for improving equity and environmental justice in its processes.

A related term is "energy justice," which has been defined by the Department of Energy as "the goal of achieving equity in both the social and economic participation in the energy system while also remediating social, economic and health burdens on those disproportionately harmed by the energy system," Bolston said.

"I think if there's a common theme, it's that some communities face systemic barriers that are either procedural or substantive that might result in inequitable regulation," he added. "And I think that achieving fair regulation and just regulation necessitates acknowledging the systemic barriers and tackling them head on."

FERC has been increasing its work in the area broadly, not just on the team Bolston leads in the Office of General Counsel. The Office of Public Participation (OPP), founded in 2021, reaches out to the general public, and the Office of External Affairs is the chief contact with Congress, states, tribes and other levels of government. The Office of Energy Projects, which reviews natural gas and hydropower infrastructure, has its own groups dedicated to public outreach and environmental justice, Bolston said.

OPP is focused on community outreach and engagement, education and technical assistance, lowering barriers to public participation before the commission and internally advocating for improved public accessibility. The office is non-decisional, which means its staff can talk about all the issues before the regulator, Bolston said. The office helps everyday citizens better understand the complex issues FERC deals with so they can be better involved in its work.

The recent focus on these issues has made a mark on FERC's NEPA documents, its environmental reporting and even the orders it issues, Bolston said.

"That's not to pat the commission on the back and say that 'we're done with our work'; it's just more of a way to level set for anyone out there that hasn't seen any of these analyses, or maybe hasn't seen the evolution," Bolston said.

One of the more high-profile steps FERC has taken on the issue was to hold an environmental justice roundtable this year, on which it has taken comments. (See *FERC Gets Advice, Criticism on Environmental Justice*.)

"Those comments are not going to lie in some docket and never be seen," Bolston said. "We actually read all the comments. We're in the process of ingesting those comments and summarizing them. We're in the process of taking those comments and adjusting our policies, practices and procedures, both internally and potentially externally." ■

Senior Counsel on Environmental Justice and Equity Conrad Bolston | *Conrad Bolston via LinkedIn*

CAISO/West News

Stakeholders Call for Structural Changes to CAISO's RA Program

Point to Lack of Visibility of Non-RA Resources amid a Changing Fleet

By Ayla Burnett

FOLSOM, Calif. — CAISO stakeholders last week questioned if the ISO's resource adequacy fleet is sufficient to meet its needs.

At a Nov. 1 meeting of CAISO's Resource Adequacy Modeling and Programming Design Working Group, Stephen Keehn, a senior adviser at Southern California Edison, said a change in the fleet requires a change in the way RA sufficiency is analyzed, and participants spent the bulk of the meeting dealing with how to adjust the framework.

Participants highlighted what they felt was a lack of visibility of non-RA resources, those resources that aren't committed to serve an RA obligation of a load-serving entity within CAISO. Without transparency on what non-RA resources exist, what they're being used for or whether they are under contract, market participants lack information on available capacity, therefore calling into question the efficiency of the RA program as a whole.

CAISO and its stakeholders are still in the early stages of grappling with how to redesign the RA program to account for changing conditions on the grid. The changes include a looming shortage of resources, increasing variability in energy supply and demand, and the evolving nature of resource planning frameworks in California and across the West.

The ISO is also contending with the rapid growth of energy-limited resources — such as batteries — on its grid, as well as the emergence in California of community choice aggregators (CCAs) as major LSEs, whose expansion has fragmented the landscape from a reliability perspective.

Representatives from CalCCA, Pacific Gas and Electric, Northern California Power Agency and the California Public Utilities Commission's Public Advocates Office called for increased visibility into non-RA.

Lauren Carr, senior market policy analyst with CalCCA, said that while CAISO has visibility into all the resources in its footprint, it's unclear what a resource is being used for if it's not included in an RA showing.

"We don't know, when we look at that list of non-RA resources, if it's just that they're not in a showing but could be dedicated to CAISO … or if they're under contract or dedicated for some other use like substitution," Carr said. "We think increased visibility into where supply that's not on an RA showing is dedicated to would be useful."

CAISO publishes monthly non-RA showings, though, leaving some confused about the lack of visibility.

"The ISO should have visibility into every resource within its operational footprint," said Brian Theaker, vice president of Western regulatory and market affairs with Middle River Power. If a resource isn't included in a showing, he explained, it's likely because of substitution or holding back capacity for planned outages, which is a problem of its own.

Larger Structural Issues

In line with Theaker's thinking, Chris Devon, director of energy market policy with Terra-Gen, suggested that the lack of visibility into non-RA resources is representative of broader structural issues such as modeling and planned outages that, if addressed, would eliminate the larger problem.

"I think that this issue of needing to increase visibility of non-RA is a symptom of the California RA overall," said Devon.

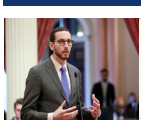
Stakeholders also suggested addressing the default planning reserve margin before discussing visibility of non-RA. Sibyl Geiselman, market policy adviser with Public Generating Pool, questioned whether the PRM was high enough to both ensure reliability and meet a one-in-10 loss-of-load expectation, adding that an increased PRM could decrease the need for backstop procurement of non-RA resources.

CAISO headquarters in Folsom, Calif. | © *RTO Insider LLC*

"If you fix the upstream issue of making sure that the program is truly providing an adequate fleet," said Geiselman, "then some of these downstream issues become hopefully less critical and less challenging because you have enough resources."

While stakeholders went further into the weeds discussing the plausibility of multiyear contracts for RA resources, counting rules and backstop procurement, they consistently returned to the theme of needing to address CAISO's entire RA modeling structure. ■

West news from our other channels



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CAISO/West News

FERC Approves CAISO Wheel-through Rule Changes

By Robert Mullin

The CAISO rules approved by FERC are intended to relax restrictions on wheel-throughs in the ISO under tight conditions. | © *RTO Insider LLC*

FERC on Oct. 30 approved a raft of CAISO tariff changes intended to ease temporary restrictions on wheeling power through the ISO's grid under emergency conditions.

The approval came despite numerous protests from Western entities that considered the revised wheel-through rules to still be overly biased in favor of CAISO's native load (*ER23-2510*).

CAISO implemented interim wheel-through restrictions in 2021 as part of a package of changes meant to promote summer reliability following the rolling blackouts and energy emergencies of summer 2020.

The rules reprioritized wheel-throughs so energy transfers between balancing authority areas in the Northwest and Southwest could no longer take precedence over capacity needed to serve CAISO native load. Under the rules, non-CAISO entities were required to apply at least 45 days in advance to designate high-priority wheel-throughs needed for reliability, giving the wheels equal standing with CAISO native load.

Until that time, CAISO — unlike other RTOs/ISOs — had never established mechanisms within its tariff to set aside transmission capacity to serve native load, notably not including native load requirements in its transmission commitments when calculating available transmission capacity (ATC).

Additionally, CAISO never adopted a transmission reservation system to protect its ability to serve native load when the ISO is constrained.

"Instead, when there was insufficient transmission capacity to support all intertie transactions, CAISO's market software determined the priority order in which self-schedules would be curtailed using real-time market parameters known as penalty prices that were set forth in a business practice manual," FERC noted in its Oct. 30 order.

In March 2022, FERC upheld its 2021 approval of CAISO's wheeling restrictions, rejecting a rehearing request by the Arizona Corporation Commission and a coalition of Arizona utilities, including Arizona Public Service and Salt River Project, which argued CAISO's rules discriminated in favor of the ISO's load (*ER21-1790*).

But the commission at the time also pointed to continued divisions over the rules in the region and directed CAISO to "work with stakeholders to design and file a just and reasonable and not unduly discretionary or preferential long-term solution as expeditiously as possible."

Changing Formulas

The CAISO tariff changes approved Oct. 30 are intended to give wheel-through transactions at the ISO's interties the same scheduling priority as that of imports serving the ISO's load. At the same time, the changes also elevate the scheduling priority of serving native load by altering CAISO's ATC calculation to set aside intertie capacity for that load.

Under the new rules, CAISO will estimate ATC at the interties "monthly across a rolling 13-month horizon and daily across a seven-day horizon to derive the amount of transmission capacity available for entities seeking a monthly or daily Wheeling Through Priority," the commission said in its order.

In its calculation for estimating the ATC for wheel-throughs at an intertie, CAISO will subtract both existing transmission commitments (ETComm) and the transmission reliability margin (TRM) from the total transfer capability (TTC) on the line. Under a new formula, the definition of ETComm is revised to include transmission ownership rights (TOR) and existing transmission contracts (ETC) — as it currently does — as well as transmission capacity for wheeling through priorities and native load needs, including native load growth in the applicable time horizon.

"CAISO states that it will initially determine the amount of transmission capacity to serve native load needs at each intertie for each calendar month based on the highest MW quantity of total RA and non-RA import supply under contract dedicated to serving CAISO load serving entities' load as demonstrated by RA showings, and showings of historical contract information regarding non-RA import supply, at the intertie for that same calendar month during the previous two years," FERC notes.

Powerex, NV Energy, the Arizona utilities and the Electric Power Supply Association (EPSA) argued CAISO's proposal for calculating ATC would be "unduly preferential" to native load and would result in the ISO setting aside more intertie capacity than necessary to reliably serve its load.

Powerex contended CAISO's own data indicates the availability of intertie capacity for priority wheel-throughs would be much lower

CAISO/West News

under the new rules than under the current interim measures. NV Energy complained about a lack of clarity in how CAISO will calculate ATC values.

The Western Power Trading Forum (WPTF) and EPSA argued the proposed ATC calculation would set aside intertie capacity for native load without requiring CAISO load-serving entities to show they have contracted firm resources in a timely manner, whereas external LSEs could secure wheeling only through priority if they meet a power supply contract requirement.

The commission brushed aside those concerns, and others, in approving CAISO's ATC calculation.

"As a threshold matter, we find no merit in any suggestion by protestors that CAISO is not entitled to set aside intertie capacity that is needed to serve CAISO load, or that it is unduly discriminatory in principle for CAISO to reserve this capacity for native load before making ATC available to external load serving entities," the commission wrote.

The commission added that "one of the core elements" of FERC's open access policies "is the ability of transmission providers to include in their tariffs certain protections to ensure reliable service to native and network load customers. [FERC] Order No. 888 establishes that public utilities may reserve existing transmission capacity for native load and reasonably foreseeable network transmission customer load growth."

'Inherent Tension'

FERC also approved CAISO's proposed process for requesting and using priority wheel-throughs. For the monthly request window, the process will require a scheduling coordinator to request a wheeling-through priority no earlier than 12 months before the month for which it seeks the priority and not later than one month before the effective date of the priority. Daily wheeling-through priorities can be requested no sooner than seven days before and no later than one day before the priority effective date.

Protestors once again contested the provision that a wheel-though request must be supported by an executed firm power supply contract. CAISO said the contract requirement was an extension of its interim wheel-through tariff provisions and consistent with the requirement for external LSEs seeking to obtain an allocation of congestion revenue rights in the ISO. The grid operator said the contract requirement helps ensure that limited ATC on the interties is accessible to those that show they need it to serve their load and comparable to how RA contracts demonstrate the same need for CAISO LSEs.

The commission said that when it accepted CAISO's interim scheduling priority rules in 2021, it explained that the firm contract requirement was not preferential for CAISO because it functions as "reasonable proxy that allows external load serving entities to demonstrate that they plan to use the CAISO grid to serve load in a manner that is comparable to CAISO load serving entities."

"We find that the commission's reasoning in that case applies with equal force here because the central issue is still the inherent tension between CAISO's need to use intertie capacity to serve its own load and third parties' ability to access that capacity," the commission wrote. ■

CAISO/West News

EIA: Renewable Curtailments Rising Steadily in CAISO

Batteries, New Transmission, Coordinated Planning Key to Reducing Curtailments

By Elaine Goodman

CAISO's curtailment of solar and wind power in California is on the rise, and about three-quarters of curtailments so far this year have been due to transmission congestion.

The remainder of curtailments in the first nine months of 2023 were due to oversupply, according to an *analysis* of CAISO data by the U.S. Energy Information Administration (EIA).

"Congestion-related curtailments have increased significantly since 2019 because solar generation has been outpacing upgrades in transmission capacity," EIA said in its report.

CAISO's solar and wind curtailments have been increasing since at least 2015, EIA found. Solar made up roughly 95% of the curtailments and wind accounted for the rest.

In 2022, CAISO's curtailment of utility-scale solar and wind was 2.4 million MWh, a 63% increase compared with 2021.

On a month-to-month basis, solar curtailment peaked in April 2023 at 702,883 MWh. That compares to the previous peak of 596,175 MWh in April 2022.

CAISO said on its website that it expects to see oversupply conditions more frequently as amounts of renewable resources grow. The ISO is pursuing several strategies to address the issue.

"Key to curtailment reductions are the interconnection process enhancements, the 2022/23 transmission planning process and increasing amounts of battery storage," CAISO spokesperson Anne Gonzales told *RTO Insider*.

California now has more than 6,600 MW of battery energy storage systems online, up from 770 MW in 2019, the California Energy Commission *reported* last month.

CAISO has also pointed to expansion of its Western Energy Imbalance Market (WEIM) as a way to reduce renewable energy oversupply and curtailment. The WEIM allows surplus energy to be shared across the region rather than reducing output.

According to EIA, trading within the WEIM prevented more than 10% of total possible curtailments in 2022.

As for CAISO's upcoming Extended Day-Ahead Market (EDAM), Gonzales said the impact on curtailment would depend on the participation footprint. She noted that energy curtailments occur in real time, while EDAM is a day-ahead market.

A state-led study last year found "incremental curtailment reductions" in a West-wide EDAM scenario, Gonzales said.

CAISO has pointed to other strategies that may reduce curtailment, including time-of-use rates and EV charging systems that respond to grid conditions. In addition, policies could be explored to reduce existing generators' minimum operating levels, making room for more renewable production.

Storage, Transmission Planning

When asked about EIA curtailment analysis, Jan Smutny-Jones, CEO of the Independent Energy Producers Association, said most solar developers are building solar-plus-storage projects to capture the benefits of meeting net peak demand.

"In addition, Western regionalization would provide a broader market for excess solar in other states," Smutny-Jones told *RTO Insider*.

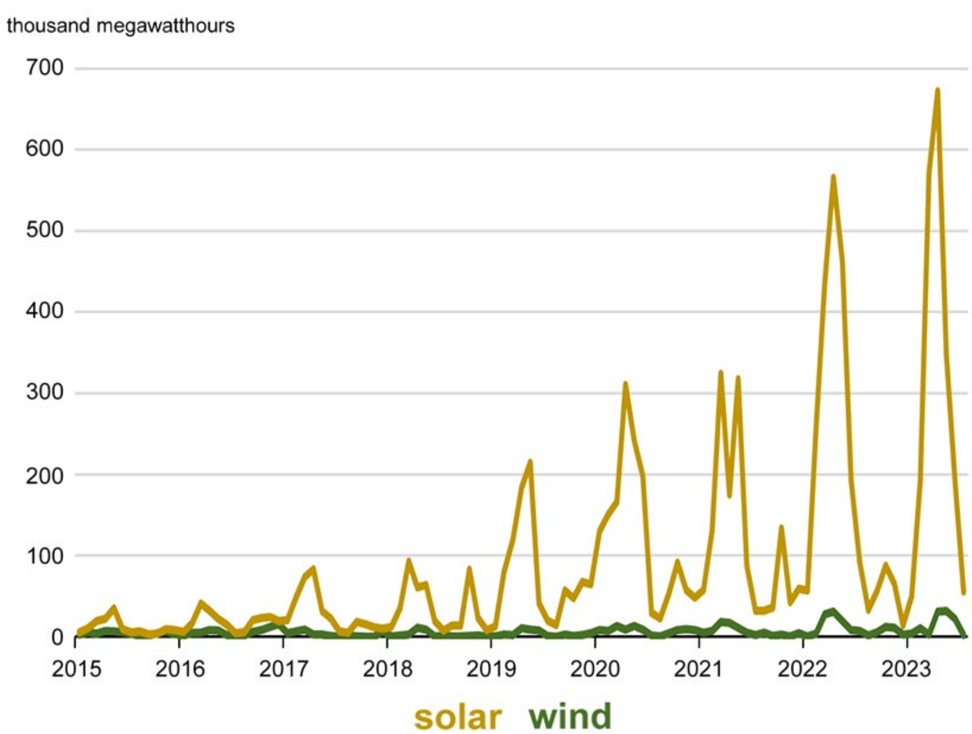
Mark Specht, Western states energy manager for the Union of Concerned Scientists, said the fact that most of the solar curtailment in California is due to congestion indicates that solar energy is getting "trapped" in certain locations without sufficient transmission to send it elsewhere.

A key strategy for solving the problem is coordinated transmission planning across the West, he said.

Battery storage is another possible way to reduce curtailment, said Specht, who recommended adding batteries to existing solar projects that lack storage.

Still, Specht said, building all the infrastructure needed to capture every drop of solar energy probably doesn't make economic sense, and "some amount of curtailment is okay."

"Zero curtailment shouldn't necessarily be the goal," Specht said. ■



CAISO's renewable curtailments have steadily increased as California brings on more solar resources. | *EIA*

APS IRP Envisions Increased Renewables, Natural Gas

Environmental Group Says Arizona Utility Must Move Faster to Reduce Emissions

By Elaine Goodman

Arizona Public Service has filed a 15-year resource plan that lays out a strategy for meeting increasing demand and replacing capacity lost from its coal plant exit.

The plan calls for investment in "hydrogen-capable" natural gas generation, which will serve as a backup for wind and solar resources and maintain reliability.

The Palo Verde nuclear plant, which APS co-owns and operates, will also help manage costs and strengthen reliability, APS said.

Renewables will grow from 16% of APS' energy mix to 43% in 2038, according to the *integrated resource plan* filed last week with the Arizona Corporation Commission (ACC).

"The immediate path ahead is clear: continued investment in affordable renewable technologies, utility-scale battery energy storage and additional hydrogen-capable natural gas facilities to provide necessary peaking and overnight load support," APS said in its IRP.

Now that the IRP has been filed, stakeholders will have an opportunity to comment and APS will have a chance to respond before the ACC reviews the plan.

Four Corners Exit

In the plan, APS promises to exit by 2031 from the coal-fired Four Corners plant, which it operates and partly owns. APS plans to no longer have ownership in the facility by 2031, the company said in an email.

Environmental groups have called for an earlier exit from Four Corners, pointing to projections of significant cost savings from a 2028 closure.

But APS said an earlier exit creates "too significant a risk to customers at this time," given obstacles to new resource development.

"APS does not support the early exit from Four Corners due to the grid reliability risks associated with the transition to newer, nascent technologies and increasingly limited excess capacity across the Western U.S. region," the plan said.

The company said it will continue to study the feasibility of leaving Four Corners before 2031 as conditions change.

The IRP has also drawn criticism for its reliance on fossil fuels. Although coal disappears from APS' portfolio after 2031, gas and oil hover at around 20% of the energy mix through 2038.

Alex Routhier, the Arizona clean energy manager at Western Resource Advocates, said APS must do more to speed its clean energy transition.

"We commend APS' pledge to double its renewable energy resources by 2030, but its plan contains significant flaws," Routhier said in a statement.

WRA said utilities must reduce their carbon emissions 80% from 2005 baseline levels by 2030 to be aligned with science-based climate goals.

APS projects its greenhouse gas emissions will fall from 9.3 million metric tons in 2023 to 6.7 million metric tons in 2038. Emissions in 2038 will be reduced 60% compared to 2005 baseline levels.

APS has pledged to be 100% carbon-free by 2050.

Growth Forecast

APS projects that its customers will need about 14,820 MW of electricity in 2038, compared with the company's 9,400 MW of total energy resources this year.

Contributing to the expected load growth are data centers and large industrial customers, which are attracted by the dry climate and low risk of natural disasters, APS said. Other factors are a growing population and electric vehicle adoption: APS expects more than 1 million EVs in its service territory by 2037.

Increased demand is projected to be 12,997 GWh for new data centers, 3,406 GWh for EVs and 657 GWh for residential customers.

To help meet the growing demand, APS plans to add more than 6,000 MW of solar and wind power, coupled with battery storage, by 2027.

The plan also calls for natural gas peaking resources, which could be built at existing coal plants, saving money by reusing existing infrastructure.

APS is planning about 1,800 MW of additional natural gas resources through 2038, partly offset by the retirement of around 300 MW of aging facilities.

Battery Storage, Microgrids

APS said it plans to invest heavily in battery storage, which will allow it to take advantage of low-priced excess solar generation from throughout the region. At times, APS said, market participants will even pay APS to take excess solar energy.

Still, the company said it's planning a "responsible integration of this nascent technology" and is capping battery storage at 3 GW through 2027.

"APS will continually evaluate this cap as more industry experience is gained," the IRP stated.

Microgrids are another strategy in the IRP. They're expected to provide about 800 MW of capacity by 2038.

APS said it could partner on microgrids with large customers, such as data centers or factories.

"Since utility-integrated microgrids are dispatchable, they provide resource adequacy critical for reliability and resiliency," APS said.

But if customers decide not to partner with APS on microgrids, the company would likely seek additional natural gas resources.

Western Market Impacts

APS joined CAISO's Western Energy Imbalance Market (WEIM) in 2016, a move that has so far saved $375 million. APS has also been involved in development of CAISO's Extended Day-Ahead Market (EDAM) and SPP's competing Markets+.

"The creation of a day-ahead market can enable additional benefits for customers, and it is critical that these markets have independent governance and that all participating entities operate on an equal footing," APS said.

The company said it expects to commit to one of the day-ahead programs after FERC approves tariffs for each.

For now, APS isn't including day-ahead market participation in the IRP's quantitative analysis.

"As potential day-ahead market structures become more certain, APS will be able to estimate the cost impacts in future IRPs from different programs and options," the company said. ■

ERCOT News

$10B Fund for Gas Plants on Texas Ballot Tuesday

By Tom Kleckner

Texas voters will finish casting their ballots today on Proposition 7, a constitutional amendment that would create a nearly $10 billion state fund for dispatchable energy that opponents say amounts to a handout for the natural gas industry.

A result of legislation passed earlier this year, the Texas Energy Fund is a $7.2 billion low-interest loan program intended for the development of up to 10 GW of natural gas plants. Some $5 billion will be set aside for 20-year, 3% interest loans to build new generation with at least 100 MW of fully dispatchable capacity. Power plants that come online before June 29 are eligible for bonus payments.

Another $2.8 billion will be dedicated to grants for infrastructure improvements in non-ERCOT regions and for grants to strengthen resiliency at hospitals, fire stations and other critical facilities through microgrids.

ERCOT considers energy storage as a dispatchable resource, but it is restricted from the program.

Prop 7 is supported by gas heavyweights such as ConocoPhillips, Koch Companies and Valero Energy, along with industrial users. They say the amendment will stabilize a creaky ERCOT grid that has struggled to meet growing demand since the 2021 winter storm.

The opposition, primarily environmental and consumer groups, object to what they call a "cleverly disguised handout to Texas gas companies that are already making record profits."

"Proposition 7 is the key to building a stronger and more resilient energy infrastructure, ensuring that we always have the electricity we need, when we need it," state Sen. Charles Schwertner, who guided Senate Bill 2627 through the Legislature, said on X, the social media platform formerly known as Twitter.

"We don't need to subsidize power plants in a private market with taxpayer funds," the Sierra Club's Cyrus Reed countered on X.

During debate over the bill this spring, several generators came out against SB2627. The Association of Electric Companies of Texas said it was concerned about government intervention in the competitive wholesale market. Other company representatives said the loans are similar to other regional programs that create market distortions.

"If you're a gas power plant developer, why would you ever develop another power plant in Texas without a grant and a low-interest loan? Do Texans need to put up billions more the next time we need more energy?" Stoic Energy CEO Doug Lewin said, while admitting "there's virtually no chance" Prop 7 will fail.

The amendment enjoys wide public support, according to a poll released last month by the University of Houston and Texas Southern University. The survey found 68% of voters favor the amendment, with 15% opposed and 17% undecided, despite its costs filtering down to ratepayers.

ERCOT called numerous conservation alerts and a Level 2 energy emergency alert during a record-breaking summer this year. The grid operator set 10 records for peak demand this summer, topping out at 85.46 GW after just exceeding the 80 GW threshold in 2022. Four years ago, peak demand was 74.82 GW. (See *ERCOT Voltage Drop Leads to EEA Level 2*.)

The fund would be endowed with $10 billion taken from the state's general revenue fund. More money from the revenue fund could be transferred into the Energy Fund.

Early voting began in Texas on Oct. 23. ■

Proposition 7 would set aside billions for new gas plants in Texas. | *Fluor*

ERCOT News

Texas PUC OKs Smaller Budget, Admin Fee Increases for ERCOT

'Electric' Market Monitor Nixed in RFP

By Tom Kleckner

Texas regulators last week rejected ERCOT's proposed budget and administration fee increase, agreeing instead to a more incremental growth in its revenues.

The Public Utility Commission cut a little over $31 million from the grid operator's original biennial budget request that was approved by its Board of Directors in June. It also set ERCOT's administration fee at 63 cents/MWh, 11.2% lower than its first ask of 71 cents/MWh. That is still a 13.5% increase over the current admin fee of 55.5 cents/MWh. It goes into effect Jan. 1 (*38533*).

ERCOT will now work with budgets of $405.7 million and $414.3 million to cover operating expenses, project spending and debt-service obligations over the next two years. It had originally requested $424.03 million and $426.99 million for 2024 and 2025, respectively.

"It is important for ERCOT to look out into the future to have stability. ... I don't like rate shock," Commissioner Will McAdams said during the Thursday open meeting. He decried the magnitude of ERCOT's financial requests during the PUC's previous open meeting in October. (See *ERCOT Defends Admin Fee Increase Before PUC*.)

ERCOT had offered to *revise the budget* to $414.7 million and 416.6 million over the next two years and the admin fee to 69 cents/MWh, taking advantage of a positive $36.2 million variance identified since the June board meeting. However, it wasn't enough. (See "F&A Proposes Revised Budget," *ERCOT Board, IMM Debate Ancillary Service Costs*.)

The commission linked its approval of the budget to ERCOT's ability to meet performance measures *suggested* by Commissioner Lori Cobos. They include:

- Delivering a value of lost load study associated with a reliability standard's development in the first quarter of 2024.
- Implementing the dispatchable reliability reserve service ancillary product "as expeditiously as possible" and aligning it with the real-time co-optimization plus battery project (RTC+B). (See "TAC Tables DRRS Revision, to Discuss Options with PUC," *ERCOT Technical Advisory Committee Briefs: Oct. 24, 2023*.)

ERCOT CFO Sean Taylor (left), CEO Pablo Vegas review the ISO's budget with the Texas commission. | *Admin Monitor*

- Implementing the performance credit mechanism market design and aligning it with RTC+B as well.

The commission also directed ERCOT to provide it with quarterly progress reports on meeting the performance measures and an annual report related to the key performance indicators in the grid operator's August *budget submission*.

After the first admin fee increase since 2016, it will not be taken up again until 2026. ERCOT CEO Pablo Vegas said this will provide staff a stable environment as they work with stakeholders to reshape the market.

"We are operating one of the most complex systems in the world, and arguably the most complicated in the United States right now," Vegas said.

Commissioner Jimmy Glotfelty urged ERCOT to "become more efficient" in reducing costs. "Too many across-the-board salary increases; too many across-the-board bonuses," he said, pointing to $23.2 million of proposed incentives.

ERCOT's plan to increase its staff from 843 to more than 1,000 was met with objections from the PUC and several stakeholders commenting in the docket. The grid operator said it needs the staff to fight legal challenges dating back to the February 2021 winter storm and to respond to a nearly 300% increase in new legislation introduced since the storm. The latter will require additional public affairs personnel and office space near the State Capitol, ERCOT has said.

Vegas said a 1,000-person headcount is typical of other grid operators. SPP, which manages transmission across a 14-state footprint — its western expansion will add at least four more — requested 707 employees in its 2024 budget request that was approved last month.

Reacting to ERCOT's plans for additional office space and more public affairs personnel, Texas state Sen. José Menéndez (D) *said*, somewhat sarcastically, "Quite frankly, I will be happy to share office space with ERCOT instead of a multimillion dollar increase to my constituents."

Monitor to Stay Independent

The PUC also accepted staff revisions to the request for proposals for the 2024-2027 market monitoring contract after receiving pushback from lawmakers and some stakeholders.

The proposed "electric market monitor" position will remain the "independent market monitor," signaling the Monitor's independence from ERCOT. State Sen. Charles Schwertner (R), the architect behind most recent market legislation, filed a letter with the commission saying the original RFP's language implied that the Monitor is no longer "truly independent" (*55222*). (See *ERCOT Monitor's Name Change Raises Legislative Concerns*.)

PUC's Barksdale English | *Admin Monitor*

"Hearing the concerns that have been expressed in public, I recognize the specific words I put in [the contract] are misleading. I want to walk those back," said Barksdale English, director of compliance and enforcement for the PUC.

The revised RFP also removes language requiring the Monitor to notify the commission before speaking publicly and clarifies that the contract's termination is to be discussed and voted on in a public forum.

Potomac Economics, which has served as ERCOT's IMM since 2006, is the only organization that has responded to the RFP. Responses were due Oct. 30, and the contract begins Jan. 1. ■

ISO-NE News

NEPOOL Votes to Delay FCA 19

Seeks Time to Consider Resource Accreditation, Seasonal Market

By Jon Lamson

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

The NEPOOL Participants Committee voted Nov. 2 to delay Forward Capacity Auction (FCA) 19 by one year, seeking time to revise its resource capacity accreditation rules and consider moving to a prompt and/or seasonal capacity market.

FCA 19, for capacity commitment period (CCP) 2028/29, is currently scheduled for February 2025.

ISO-NE recommended the one-year delay in September but has yet to make a recommendation on the larger market changes under contemplation. While the current FCA is typically held three years prior to the CCP and covers a year-long period, a prompt auction would reduce the time between the auction and the CCP to a few months. A seasonal auction would break up the commitment period into two or more distinct seasons per year. (See *ISO-NE Recommends Delaying FCA 19* and *Discussion Continues on ISO-NE Capacity Market Changes*.)

If ISO-NE ultimately decides to stick with the existing three-year FCA format after the delay to FCA19, the RTO has proposed that the following five FCAs be conducted on a 10-month cycle, instead of the current year-long process, to eventually return the auction process to its current timeline. If the RTO elects to move to a prompt auction for FCA 19, it will void the timeline instituted by the delay. (See *ISO-NE Details FCA 19 Domino Effect*.)

The proposed delay must be approved by the ISO-NE board and then submitted to FERC for approval.

In response to concerns about the effects of the delay on new resources seeking FCA qualification, ISO-NE proposed *two changes* which were generally applauded by stakeholders. FCA qualification is necessary for resources to be eligible for reconfiguration capacity auctions, which can allow them to receive capacity payments in the near term.

First, ISO-NE agreed to allow resources lacking capacity supply obligations to submit qualification materials using the typical FCA timeline, to prevent a delay in their ability to participate in reconfiguration auctions for earlier CCPs.

Second, the RTO noted that peak demand resources are defined after the capacity qualification deadline, which would be shifted back by a year under the proposed delay.

To address concerns about negative effects this could have on demand resources looking to qualify in FCA 19, ISO-NE proposed that new demand capacity resources in FCA 19 will include on-peak demand resources and seasonal peak demand resources "consisting of measures that have not been in service prior to June 1, 2024."

ISO-NE has proposed a January 2024 effective date for the tariff changes and is continuing discussions on the potential move to prompt and seasonal market constructs. ■

ISO-NE News

FERC, NERC Leaders Voice Concern About Loss of Everett Marine Terminal

By Jon Lamson

The retirement of the Everett LNG import terminal could jeopardize the reliability and affordability of the region's electric and gas networks, FERC Chair Willie Phillips and NERC CEO James Robb wrote in joint *comments* issued Monday.

Based on the evidence presented to FERC at the New England Winter Gas-Electric Forum in June, Phillips and Robb said they have "serious concerns about certain local gas distribution systems' ability to ensure reliability and affordability in the region without Everett."

"As discussions regarding the future of Everett continue, we encourage all parties to keep reliability and affordability at the center of those negotiations," they added.

Phillips and Robb highlighted the fallout from Winter Storm Elliott in December 2022, noting that reduced flows of gas, combined with requests from shippers for increased gas volumes, cause pipeline pressures to plummet. (See *Déjà Vu as FERC, NERC Issue Recommendations over Holiday Outages*.)

"That dynamic put significant stress on the natural gas system, which only narrowly avoided significant outages," Phillips and Robb wrote. The officials referenced emergency LNG injections made by Consolidated Edison that saved its system from collapse, noting that "it would have taken 'many months' to restore service, leaving hundreds of thousands of natural gas customers without heat in the middle of winter."

Speaking at the New England-Canada Business Council (NECBC) Executive Energy Conference on Nov. 1, Robb said the Northeast "dodged a major bullet last winter during Elliott."

"Had the temperature not warmed up on Christmas Day, Con Ed and National Grid likely would have been interrupting gas customers because the pipelines were losing pressure," Robb added. "The restoration of a major natural gas system like the one serving New York City — we would likely still be in the process of lighting pilot lights."

Regarding the electric system, recent studies from ISO-NE projected out through 2032 have indicated that Everett may not significantly increase the reliability of the grid under extreme winter weather conditions. Despite these findings, RTO officials have indicated that it would be wise to retain the facility to hedge against uncertainty in the future energy mix. (See *NE Stakeholders Debate Future of Everett at FERC Winter Gas-Elec Forum*.)

An LNG facility in Everett, Mass. | *Constellation Energy*

Phillips and Robb echoed these concerns about uncertainty, noting that if ISO-NE's assumptions regarding load growth, new resources and transmission, and retirements prove to be wrong, "ensuring reliability and affordability could become challenging in the face of a significant winter event."

They said that ISO-NE and stakeholders should pursue reforms to incentivize generators to procure the necessary fuel to keep the grid running during extreme storm events.

"To the extent that Everett or other infrastructure plays a role in supporting electric reliability by making needed energy supplies available, in the near term or the future, such reforms should consider how to ensure that any needed reliability contributions are appropriately valued," Phillips and Robb wrote.

ISO-NE declined to comment on the joint statement.

The Mystic Agreement — through which New England ratepayers cover the costs of Everett's main customer, the Mystic Generating Station — is set to expire after this winter, coinciding with the retirement of the plant. Negotiations between Constellation (which owns both Everett and Mystic) and the local gas distribution utilities to keep Everett open have yet to produce an agreement.

Speaking at the June forum, Carrie Allen of Constellation told FERC that "the future of the facility is not ensured" and that "we're just running out of time." Allen added that even if an agreement is reached to keep Everett open, there would still likely be a nine-month regulatory process.

"There is no hard-and-fast drop-dead date," Allen said, adding that "normally, I think we would have the supply procured at this point."

New Hampshire Consumer Advocate Donald Kreis, who has been a vocal opponent of propping up Everett through electric rates, called the statement from Phillips and Robb "disappointing and a bit puzzling."

While Everett may be needed for Massachusetts gas distribution companies, Kreis told *RTO Insider*, ISO-NE studies show the facility is not necessary for grid reliability and therefore its costs should not be charged to the region's electric ratepayers.

He called Phillips and Robb's comments "potentially an unhelpful scare tactic" that could "cause people to feel a sense of alarm without any basis for doing so." ■

ISO-NE News

Advanced Energy United Urges Changes Beyond Order 2023 for ISO-NE

By Jon Lamson

ISO-NE should go beyond the changes required by Order 2023 to address the high costs and long delays associated with interconnection in the region, Advanced Energy United advocated in a *white paper* released Nov. 1.

"The costs imposed by inefficiencies in the interconnection process are borne by ratepayers in the region and are one significant factor which threatens the New England states' decarbonization goals," United wrote. The association represents clean energy and storage developers, owners, and operators in the region.

The organization detailed specific recommendations for the RTO's compliance filing, along with longer-term actions to take to address issues that will not be addressed in the filing.

"While it is critical that Order 2023 is addressed and that a solid compliance package is submitted to the commission, we stress that this marks the beginning of the region's interconnection process reform efforts," United wrote. "Changing technology, policy efforts and expected FERC orders on planning and cost allocation, among others, makes continued attention to comprehensive market reform imperative."

Regarding ISO-NE's Order 2023 compliance, United said ISO-NE should work to limit the potential for restudies and keep the cluster study window to the 150-day time frame prescribed by FERC, instead of the RTO's proposed 270-day cluster window. (See *ISO-NE Details Proposed Order 2023 Compliance*.) The group said that reducing interconnection timelines was one of the main goals of the commission's order, and a longer cluster study window could push back subsequent clusters.

ISO-NE representatives have said it is difficult to guarantee it will be able meet the 150-day timeline, in part because of the undetermined number of projects it may need to consider in any given cluster.

United also recommended that ISO-NE clarify its methodology for studying separate subgroupings of projects within a given cluster. The group said the RTO should publish the data and assumptions used in each cluster study in conjunction with its results.

"The process the ISO intends to use in each cluster study should be known before the cluster request window opens so that interconnection customers can replicate the process, if they so choose, and make fully informed decisions," United wrote.

Regarding alternative transmission technologies (ATTs), United said ISO-NE should include dynamic line ratings with the other ATTs to be considered in interconnection studies. United also called on the RTO to provide transparency around how each alternative will be considered in the study process and detail the results of ATT evaluations in study reports.

Looking beyond Order 2023 compliance, United called for more disclosure around expected regional interconnection costs for project developers prior to interconnection studies, saying this could reduce the number of projects that drop out mid-process.

"Hand-in-hand with providing the data is ensuring that each study cycle follows a well-documented study approach," United added. The group also said ISO-NE and the region's transmission owners should work to minimize uncertainty within interconnection cost estimates and advocated for an upper limit to the cost overruns that can be charged to developers.

Finally, the association said spreading costs among a cluster of projects is a good first step toward properly allocating costs associated with interconnection upgrades. At the same time, ISO-NE should consider further steps to share the costs of upgrades with all beneficiaries, United wrote.

"The establishment of a cost-allocation structure that is simple to administer, clear to all participants and fair to interconnection customers, the TOs and ratepayers should be a reform priority," United wrote, adding that interconnection upgrades can benefit state policy goals, enable increased electrification, promote system resilience and increase market competition.

"We recommend that the ISO pursue a cost allocation rule that would recognize the headroom created by a set of network upgrades and charge the projects in the cluster only for the system capability they needed to interconnect," the association recommended, saying this would be conducive in the long term to "more closely coordinated planning of the system to address the reliable delivery of power to load and the interconnection of projects without distorting incentives." ■

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Infrastructure and Coordination Hot Topics at NECBC Conference

By Jon Lamson

The U.S. and Canada must increase interregional ties and cooperation to ensure reliability and affordability in the clean energy transition, government officials and industry executives from both sides of the border said at the New England-Canada Business Council's 31st Annual Executive Energy Conference.

Speakers at the conference, which met in Boston on Thursday and Friday, highlighted the potential co-benefits of offshore wind and hydropower, arguing that increasing the bidirectional connections between New England and Eastern Canada would boost the reliability and affordability of the future grid.

Two days prior to the start of the conference, the U.S. Department of Energy announced that it will become the anchor off-taker for the 1,200-MW Twin States Clean Energy Link project, which will connect Vermont and New Hampshire to Québec. (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.) The line will allow for the bidirectional flow of electricity, enabling New England to import hydropower from Québec and export excess offshore wind energy depending on regional needs.

Maria Robinson, director of DOE's Grid Deployment Office, told the conference that the project will "enhance the capacity of the grid here in New England as well as provide additional resilience, reliability and efficiency between our two countries."

"The line will certainly deliver clean energy from Canada through hydropower to New England, and potentially at some point soon to Canada through solar and offshore wind here in the United States," Robinson added.

Serge Abergel of Hydro-Québec touted the potential benefits of using hydropower to balance out wind power and reduce curtailment instead of simply using hydropower as baseload.

Hydropower "can essentially follow the patterns of wind," Abergel said. "There is the potential for us to optimize and not send 24/7 but send energy when needed and get back excess power when there's too much [in New England]."

Hydro-Québec on Thursday *announced* its plans to spend about $100 billion to increase its production and grid capacity. The company is hoping to add up to 4,200 MW of hydropower production capacity, from both new dams and renovations to existing facilities.

From left: Tristan Doherty, LG Energy Solution Vertech; John Dalton, Power Advisory; Alicia Barton, FirstLight Power; Éric Lachance, Energir; Rachel McCormick, Natural Resources Canada | © *RTO Insider LLC*

A Difficult Transition

Throughout the conference, speakers emphasized the vast amount of infrastructure that will be needed to meet the energy transition, as well as the significant costs and regulatory challenges that it will entail.

"On the broader permitting side, very few people, I fear, appreciate the scope of what net zero looks like," said Christopher Guith, senior vice president of the U.S. Chamber of Commerce's Global Energy Institute, citing the need for new transmission lines and pipelines to move carbon dioxide or hydrogen.

Guith said there is bipartisan acknowledgement that the permitting process needs major changes, and Democrats and Republicans in the Senate will ultimately need to "sit down like big boys and big girls and figure out how to get the 60 votes."

"It is so much easier to make targets than actually achieve them," said Monica Gattinger, professor of political studies at the University of Ottawa. "There is a growing recognition of 'holy crap, this is a lot more complicated than we realized.'"

Gattinger added that navigating the sometimes competing needs for decarbonization and affordability is proving to be a challenge for policymakers across Canada.

"We do a lot of tracking of public opinion at the University of Ottawa, and when people have their hats on as citizens, they are all for climate action," Gattinger said. "But if they put on their hats as consumers … affordability and issues around siting start to become much more important."

Multiple speakers emphasized the importance of community engagement to ensure tangible local benefits, and education to connect new infrastructure needs and rising electric bills to climate change and emissions reductions, as a way to help bridge this gap.

"It isn't engineering that's our issue in Canada, and I don't think it is in the United States either" said Jacob Irving, CEO of the Energy Council of Canada. "The No. 1 most difficult thing is public acceptance of these projects."

Irving, along with most of the Canadian panelists and presenters, spoke about the importance of strong relationships with indigenous communities. Several of the speakers acknowledged the historical disregard that energy

ISO-NE News

developers have often had for indigenous communities, although no indigenous groups from either country were represented among the conference's speakers.

"If you do not have sufficient partnership with indigenous communities, you do not have a project in Canada," Irving said.

More Gas?

Asked whether New England needs to increase its gas import capacity to meet growing demand on the grid, Stephen Woerner, president of National Grid New England, and Joseph Purington, CEO of Central Maine Power, said that gas may be needed until clean energy can displace it.

"Any shortage of fuel to make electricity jeopardizes reliability, and if we're going to become more dependent on the [electric] system, we have to make sure that that doesn't happen," Woerner said. "Cost-effective long-term storage can help, but it doesn't eliminate the need for fuel."

"We need the bridge to get from where we are today to where we're going to be," said Purington. "I think that's going to have to be part of that solution as it is right now. Especially if we're continuing to stumble out of the gate."

Enbridge announced earlier this fall that it is pursuing a project to expand pipeline capacity into New England to address projected de-

From left: Paul Hibbard, Analysis Group; Heather Chalmers, GE Canada; Joseph Purington, Central Maine Power Company; Stephen Woerner, National Grid New England | *© RTO Insider LLC*

mand increases from both the gas network and the grid. The project has been heavily criticized by local climate and environmental groups. (See *Enbridge Announces Project to Increase Northeast Pipeline Capacity*.)

Meanwhile, Jamie Van Nostrand, chair of the Massachusetts Department of Public Utilities, expressed concern in September about the state's gas utilities continuing to add connections to the distribution network, saying that it seems to be "business as usual in the natural gas industry with respect to new residential hookups and continuing levels of load growth." ■

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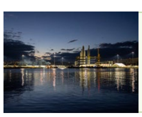

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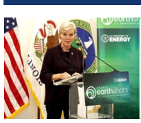

DOE to Cut Costs of Building Decarb with $30M BENEFIT Program — NetZero Insider

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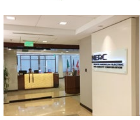

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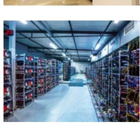


EPRI: Changing Loads Raise Concerns for Modelers — ERO Insider

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

MISO News

New Report Finds MISO and PJM Could Save Billions Through Interregional Tx Expansion

By Amanda Durish Cook

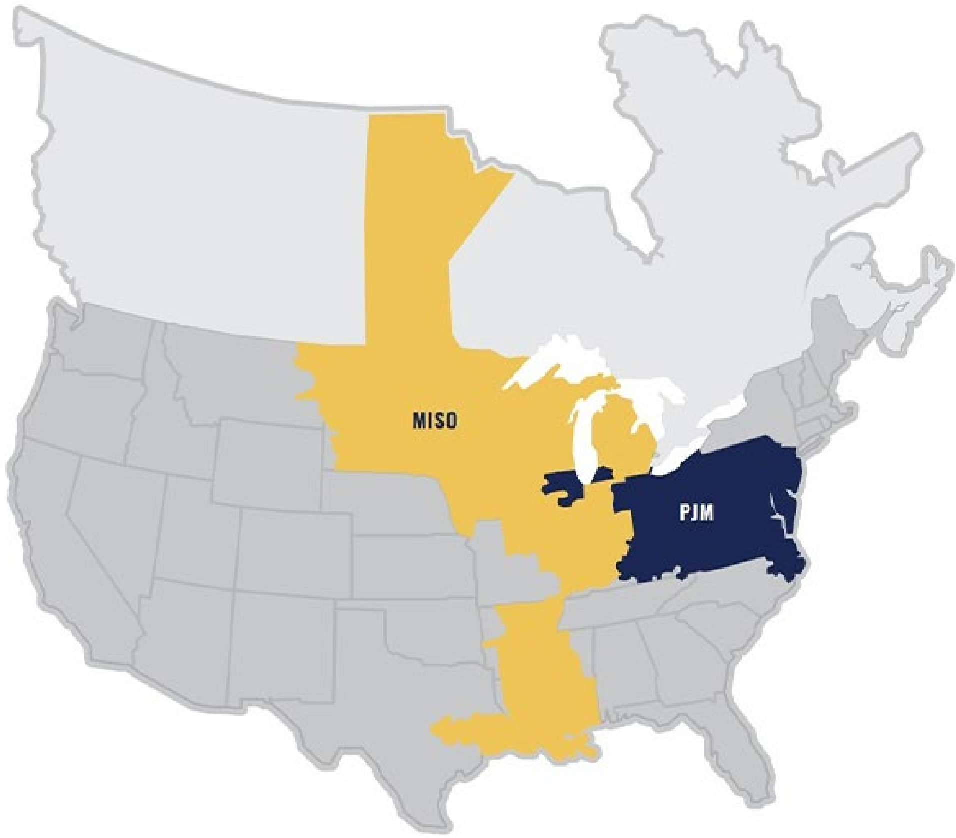
A new report from the American Council on Renewable Energy (ACORE) concludes *MISO* and *PJM* could save ratepayers $15 billion in a little more than a decade if they concentrate on building more interregional transmission.

The report, *Billions in Benefits: A Path for Expanding Transmission between MISO and PJM*, concludes more interregional ties between the Midwest and mid-Atlantic could reduce customer costs primarily through curbing the need for new generation capacity.

ACORE, Grid Strategies, the Solar Energy Industries Association (SEIA) and the American Clean Power Association (ACP) had a hand in producing the report.

Michael Goggin, Grid Strategies | *Grid Strategies*

Grid Strategies Vice President and report author Michael Goggin said greater interregional transfer capability along the seam would allow MISO and PJM to "tap into" their geographic diversity from renewable energy stretching from the Dakotas to Virginia. In turn, PJM and MISO Midwest could scale back capacity needs by about 11 GW. He said it's unlikely extreme weather envelops both regions simultaneously and both have depleted capacity reserves.



The MISO-PJM seam | Grid Strategies

During a Nov. 2 teleconference to discuss report findings, Goggin said if MISO-PJM lines are built, reduced capacity needs alone could save MISO and PJM ratepayers about $9 billion by 2035. The report also expects that expanded interregional transmission could provide more than $1 billion in energy market savings per year by reducing transmission congestion between the RTOs.

Goggin said more transmission capacity is valuable to maximizing existing generation during storms or heat waves "because of how weather systems move across the country," with either MISO or PJM peaking first and then being able to export lower-cost power.

"In the likely scenario that solar penetrations are higher in PJM and wind penetrations are higher in MISO, PJM will export power to MISO during the day and during the summer, while it will import wind power from MISO at night and during the fall, winter and spring, when wind output tends to be highest," Goggin wrote in the report.

The report didn't analyze greater links between PJM and MISO South due to the subregion's distance. It focused instead on the "long and tangled border across Illinois, Indiana, Michigan and Kentucky."

Goggin said MISO-PJM interregional transmission "functions like an insurance policy, and we need to plan and pay for it accordingly." He urged MISO and PJM to "look across the seam" and plan beyond their footprints.

Goggin said MISO and PJM's interregional planning needs a "proactive, multivalue planning approach" that accounts for the most economic future fleet mix alongside state decarbonization goals and isn't simply reactive to interconnection queue entrants.

"There are billions of dollars on the table. I think there's a way PJM and MISO can come together and make this work," Goggin said.

Goggin said congestion costs between MISO and PJM due to constraints last exceeded $1.7 billion in the 2021/22 planning year.

"This adds up to a large amount of money," he said.

He also said from 2011-2020, interregional transmission builds nationally have averaged just 70 miles per year, a "dismal" figure.

Goggin recommended MISO and PJM model their interregional planning using the success stories from SPP, ERCOT and MISO's own regional processes. He said MISO and PJM also could model planning after MISO and SPP's Joint Targeted Interconnection Queue (JTIQ) study, which is meant to interconnect generation at the seams.

Goggin pointed out that PJM's 2014 Renewable Integration Study and MISO's 2017 Regional Transmission Overlay Study yielded similar, possible high-voltage solutions in northern Indiana and Illinois and at the MISO seam at the Iowa border.

He said MISO and PJM's current affected system studies — the RTOs' means of studying interconnecting generation near the seam —

are designed so additional transmission upgrade costs are tacked on nearly at the finish line of the RTOs' queues, a "nasty surprise that reshuffles the entire queue."

Goggin said MISO and PJM should allow merchant transmission developers to "propose interregional solutions and be fully compensated for the value their projects provide." He said projects like the Grain Belt Express and SOO Green HVDC Link are poised to be valuable in increasing links between the Midwest and mid-Atlantic and they should be accounted for in MISO and PJM planning processes.

However, Goggin warned PJM lags in building proactive, large projects even regionally, focusing instead on local reliability projects to replace aging infrastructure.

SEIA Counsel and Director of Energy Markets Melissa Alfano said more powerful interregional connections would allow the country to move away from "toxic" thermal resources that often fail during extreme weather events, especially in recent winter storms. She said a stronger interregional system also would help alleviate cascading project withdrawals in the MISO and PJM generator interconnection queues.

"All of these benefits are undeniable. … Yet here we are not building interregional transmission," Alfano said.

She added that aside from groups urging MISO and PJM to do more, FERC should issue a rule on interregional planning standards. She said it seems meaningful interregional planning between MISO and PJM won't happen absent a FERC mandate.

Jeff Dennis, deputy director of transmission at the Department of Energy's Grid Deployment Office, said significantly more interregional transfer capacity between the Midwest and mid-Atlantic is one of the key needs outlined in last week's *National Transmission Needs Study* from the DOE.

Katharine McCormick, assistant director of policy division at the Illinois Commerce Commission, said both PJM and MISO have been consistently warning over 2023 that they're facing reliability risks by the end of the decade. She said building interregional transmission would aid reliability.

ACP Senior Counsel Gabe Tabak said DOE's recent funding assist for MISO and SPP's JTIQ $2 billion portfolio of 345-kV lines is a good starting point to encourage more interregional planning. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

"Meaningful" federal cost sharing is a way to "unstick the process that we all know needs to be advanced," Tabak said.

MISO, PJM Mum on Conclusions

Both MISO and PJM said they still are reviewing the study and couldn't speak to the findings.

"MISO is committed to interregional coordination in both planning and operations," spokesperson Brandon Morris said in an emailed statement to *RTO Insider*.

At the Organization of MISO States' annual meeting at the end of October, MISO Senior Vice President of Planning and Operations Jennifer Curran said MISO will attempt to plan a JTIQ-style portfolio with PJM. However, she warned that MISO and PJM employ different planning styles that are difficult to reconcile. (See *OMS Leaders Reminisce on 20 Years at Annual Meeting*.)

MISO and PJM have approved one large *interregional market efficiency project* in 2020 and four sets of *smaller* transmission projects aimed at relieving congestion since 2017.

Still, the nonprofits that signed onto the report are hoping for more from MISO and PJM.

"The U.S. Department of Energy has found that the MISO-PJM seam has the greatest need for expanded interregional transmission ties," ACP Vice President of Markets and Transmission Carrie Zalewski said in a press release. "In fact, the intertie with MISO accounts for around 80% of PJM's total need for interregional transmission. These grid operators must collaborate on the transmission planning necessary to bridge this gap, preserve reliability and benefit millions of customers."

"Interregional transmission lines have helped save American lives during extreme weather events, yet today's transmission planning processes do not value the added reliability they provide our grid," ACORE CEO Gregory Wetstone said. "Consumers should not be forced to endure outages when study after study shows additional line capacity would help keep the lights on and reduce power costs." ■

MISO News

MISO Selects Ameren to Build 2nd Competitive LRTP Project

By Amanda Durish Cook

MISO has awarded Ameren Transmission Company of Illinois (ATXI) the lead in building a pair of lines and substation in northwest Missouri, the second competitively bid project stemming from the RTO's $10 billion long-range transmission plan (LRTP).

The Ameren subsidiary plans to partner with the Missouri Joint Municipal Electric Utility Commission on development of the $84 million, 345-kV Fairport-Denny project, extending to the Iowa-Missouri border. ATXI plans to sell 49% of the project to the Missouri state utility agency just before the project is placed in service in 2030.

MISO said ATXI was one of four developers to submit *project proposals*, with LS Power Midcontinent, NextEra Energy Transmission Midwest and Transource Energy offering nine. MISO does not reveal the companies behind non-winning bids, although it said one developer submitted six proposals based on differing designs. It said proposals ranged from $84 million to $134 million for project implementation. MISO originally estimated the Fairport-Denny project would cost $161 million. The RTO said cost differences between proposals came down to conductor size, substation design and tax liabilities.

Jeremiah Doner, MISO's director of cost allocation and competitive transmission, said ATXI's proposal incorporates "strong cost containment and a sound design." MISO said ATXI pledged annual revenue requirement caps and carefully considered pre-construction studies and proposed routes.

"Ameren's proposal, submitted with its partner MJMEUC, had a substantially lower cost than that of the next closest proposal, which was 36% higher based on the annual costs to customers over 40 years," Doner said in a press release.

MISO said ATXI will execute a selected developer agreement. Doner said MISO looks forward to "working closely with the developer, regulators and other stakeholders to support a successful and on-time completion of the project."

In a press release, ATXI President Shawn Schukar said the project bid was the "result of a collaborative effort with many community partners who have the best interests of our state in mind."

He said ATXI will continue to solicit input from the community to build affordable transmission projects.

MISO is simultaneously managing multiple RFPs related to the first LRTP portfolio.

The grid operator opened an RFP for another LRTP project in March. It seeks bids on the $556 million Denny to Zachary to Thomas Hill 345 kV project, part of which will link up with the Fairport-Denny project. Proposals are due Nov. 14. (See *MISO Begins LRTP's 2nd RFP Process*.)

| Ameren

The half-billion-dollar solicitation is MISO's most expensive request for proposals.

The grid operator also opened two other RFPs in July: the $12 million Deadend to Tremval 345-kV project in Wisconsin and a $23 million, 345-kV line segment from the Iowa-Illinois border to the Ipava substation in Illinois. It will select developers for the trio of projects over 2024.

In May, MISO selected LS Power's Republic Transmission to build the $77 million Hiple 345-kV line at the Indiana-Michigan border. It's MISO's first competitive project surfacing from the LRTP. (See *MISO Picks Republic Transmission for 1st LRTP Competitive Project*.)

In MISO, competitive transmission developers must be members and must be prequalified to bid on competitive projects. Developers must include a $20,000 application fee and a $100,000 initial deposit to have their bids considered by MISO.

MISO's decision to go with ATXI for the LRTP competitive builds comes as a right of first refusal (ROFR) bill for downstate Illinois fizzled out, with supporters last week acknowledging they don't have enough votes in the Democratic-controlled General Assembly to overrule Gov. J.B. Pritzker's August veto of the ROFR portion of energy legislation approved in the spring. (See *Ill. Gov. Vetoes Downstate ROFR for MISO Regional Tx Projects*.)

The bill would have given ATXI exclusive rights to build regional MISO transmission lines in its territory and shut down MISO's competitive bidding process for future projects in downstate Illinois. ATXI backed the legislation.

Recently, ATXI Chairman and President Leonard Singh wrote in a letter to state lawmakers that the company had been "subjected to well-funded misinformation campaigns by out-of-state developers and special interests" who opposed the ROFR.

Singh said a ROFR would keep transmission projects under state — rather than federal — control and remains "the best option to prevent unnecessary delays in construction and hundreds of millions of dollars in potential cost overruns."

Rep. Larry Walsh (D-Elwood), who sponsored the original measure, said he would reintroduce even broader legislation in spring that seeks to install a permanent ROFR on transmission projects for all utilities in the state. ■

MISO News

Nonprofits Attempt to Force a More Transparent TVA IRP Process

By Amanda Durish Cook

Several nonprofits are calling on the *Tennessee Valley Authority* to make its integrated resource planning process more transparent as the federal utility charts its resource mix over the next 25 years.

Energy Alabama, Appalachian Voices, Southern Alliance for Clean Energy, Center for Biological Diversity, Vote Solar and Green Workers Alliance submitted a *motion* to intervene last week in TVA's 2024 integrated resource plan and environmental impact statement. They pressed the TVA Board of Directors to direct TVA to hold public hearings, create a more open process and let stakeholders sound off on the resource planning study.

The groups said TVA's IRP will "influence reliability, electricity bill affordability, air and water quality, and regional jobs over the next two to three decades." They noted that unlike most utilities, TVA's IRP isn't regulated by a public service commission and impacted stakeholders aren't permitted to participate in the process unless "hand-selected" by TVA to join its 24-member IRP working group. The nonprofits said it remains unclear how an interested party can approach TVA to express interest in serving on the working group. They also said it appears the IRP working group simply comments on plans already under development by TVA, with no indication the group offers any meaningful alternatives to generation plans.

"TVA's IRP and [environmental impact statement] process is not transparent. There is no publicly available list of working group members. Agendas are not posted before meetings. There is no public comment opportunity at working group meetings, nor are these meetings open to the public. To the extent that information is made available to the public, such information consists of perfunctory summaries of decisions made, rather than the data and models that are used in the development of initial and final energy resource strategies and scenarios," the nonprofits wrote in the motion.

TVA anticipates releasing its IRP sometime next year. It last conducted an IRP in 2019.

The federal utility issued a notice of intent for its 2024 IRP in mid-May, followed by a 45-day public comment period (*PPLPWR-11-2023*). The nonprofits criticized TVA for imposing multiple, overlapping comment periods on environmental impact statements for key projects that will factor into the IRP, including a guidance

TVA's Kingston Fossil Plant near Kingston, Tenn. | *TVA*

analysis for solar and battery additions, a study on the Kingston Fossil Plant *retirement*, a study to evaluate increasing pumped storage hydropower capacity and an evaluation of the planned, 900-MW, natural gas-fired Cheatham County Generation Site.

The groups also said it was inadequate for TVA to hold just two limited participation scoping *meetings* in late spring on the IRP where the public was permitted only to ask "clarifying questions." They said TVA's timeline doesn't account for public comment on its resource strategies and scenario modeling, and that modeling already may have begun or will begin soon.

"TVA's reluctance to adopt a public Integrated Resource Plan process is truly a shame," Vote Solar Regulatory Director Jake Duncan said in a press release accompanying the motion. "Having worked in IRPs in other states, I've personally witnessed the transformative power of a public process, which not only enhances outcomes but also provides an opportunity for utilities to embrace clean energy and address energy justice concerns, benefiting everyone."

"Advocates are asking for an open and transparent planning process, including bare-minimum standards for public input that are available in IRPs at similar-sized utilities," Appalachian Voices' Bri Knisley said. "The TVA board can and should call for a public hearing and allow input and analysis from any relevant outside experts who wish to provide input in the IRP."

Gaby Sarri-Tobar, energy justice campaigner at the Center for Biological Diversity, said by "concealing" its long-term planning, TVA is failing its customers.

"As energy prices go up and extreme weather looms, there's absolutely no excuse for TVA to keep people in the dark about plans that will affect their lives for decades. These folks are paying TVA's bills, and they live with the health and safety costs of the fossil fuel status quo. It's insulting to exclude them from the planning process," Sarri-Tobar said.

TVA Maintains IRP Process is Transparent

TVA, however, insists its IRP procedure is already "fully transparent," with stakeholder engagement a critical piece of the process.

Scott Fiedler, of TVA's media relations team, said the TVA IRP working group is a "diverse" stakeholder group and that TVA updates the public on its IRP process through meetings of the TVA board and its *Regional Energy Resource Council*, which is composed of regional governmental representatives, academics and consumer advocates.

Fiedler noted that council meetings are open to the public, with the next occurring today in Tupelo, Miss. He said that will be followed by a TVA board listening session and TVA board meeting — also in Tupelo — this Wendsday and Thursday, respectively. Fiedler also said TVA is planning to host another public webinar on the IRP in December.

Finally, Fiedler said TVA will again collect public opinions in spring when it releases its draft IRP and environmental impact statement. He said TVA will plan "a number of public meetings and other engagements to share those drafts and have opportunities for the public to provide feedback."

"Bottom line: TVA is fully transparent, and we encourage the public to get involved in how their energy is generated. Together, we can build an energy system that is low cost, reliable, resilient and sustainable that will continue to drive jobs and investment into our region and power the new clean economy," Fiedler said in an email to *RTO Insider*. ■

MISO News

FERC OKs Inflation-based Bump to MISO Queue Entry Fee

By Amanda Durish Cook

MISO has received FERC approval to increase its non-refundable interconnection request application fee, required for generation developers to enter the queue.

As of Oct. 31, MISO can raise the circa-2008, $5,000 application fee to catch up with 15 years of inflation and can continue to increase it into the future to keep pace with inflation (*ER23-2742*).

MISO interconnection customers pay the non-refundable application fee alongside each new request for interconnection service. The fee covers MISO's costs to review interconnection requests, perform studies and facilitate negotiations for generator interconnection agreements.

MISO will use its original 2008 fee as a starting point and increase it every three years, commensurate with its value in today's dollars using the inflation calculator from the U.S. Bureau of Labor Statistics. The RTO said it wanted to be able to consistently raise fees and avoid multiple future FERC filings seeking permission.

FERC said it's reasonable for MISO to "account for inflation on a consistent schedule and ensure that sufficient study deposit funds are available to cover all necessary expenses.

"This should contribute to more efficient processing of MISO's interconnection queue, which will minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable," FERC wrote.

MISO said for the past 15 years, the application fee has stayed static while its costs to process interconnection requests have increased.

MISO's second, refundable study deposit will remain an escalating amount based on megawatt size of the proposed generation project. That deposit ranges from $50,000 for an up-to-6-MW project and up to $640,000 for a 1-GW or greater project.

MISO's request for inflation-based fee adjustments is separate from its package of more strict entry and exit rules to relieve pressure on its overcrowded interconnection queue. (See *MISO Relaxes Proposal on Stricter Queue Ruleset*.)

MISO will split its suite of stiffer interconnection rules into two filings at FERC. One tackles proposals for tighter land requirements, an automatic penalty schedule for withdrawn projects and increases to the milestone payments MISO collects from interconnection customers as projects move through the queue.

The other proposes an annual megawatt cap on project submissions according to a feasibility formula. MISO has said there are only so many potential generation projects it can simultaneously consider and still produce accurate interconnection studies. ■

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MISO News

MISO Reports Lower Prices over September Operations

By Amanda Durish Cook

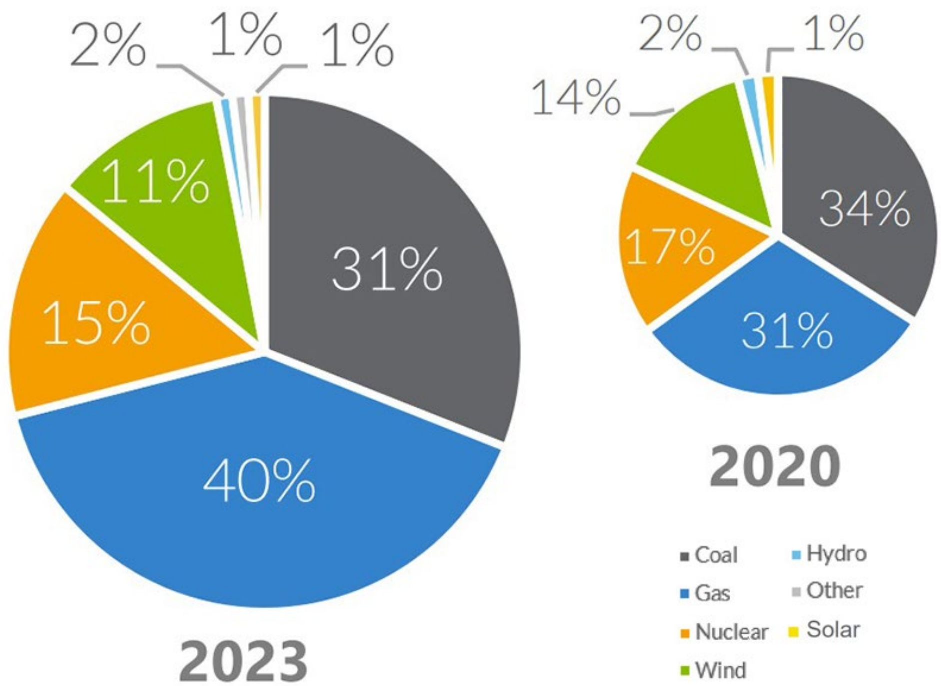
Energy prices continued a year-over-year downward trajectory in September, MISO operations data showed.

The RTO *reported* real-time energy prices averaged $30/MWh over September, down from $68/MWh during the same period last year. Average natural gas and coal prices both dipped to $2/MMBtu for the month in the footprint, sliding from $8/MMBtu for coal and $7/MMBtu for natural gas in September 2022.

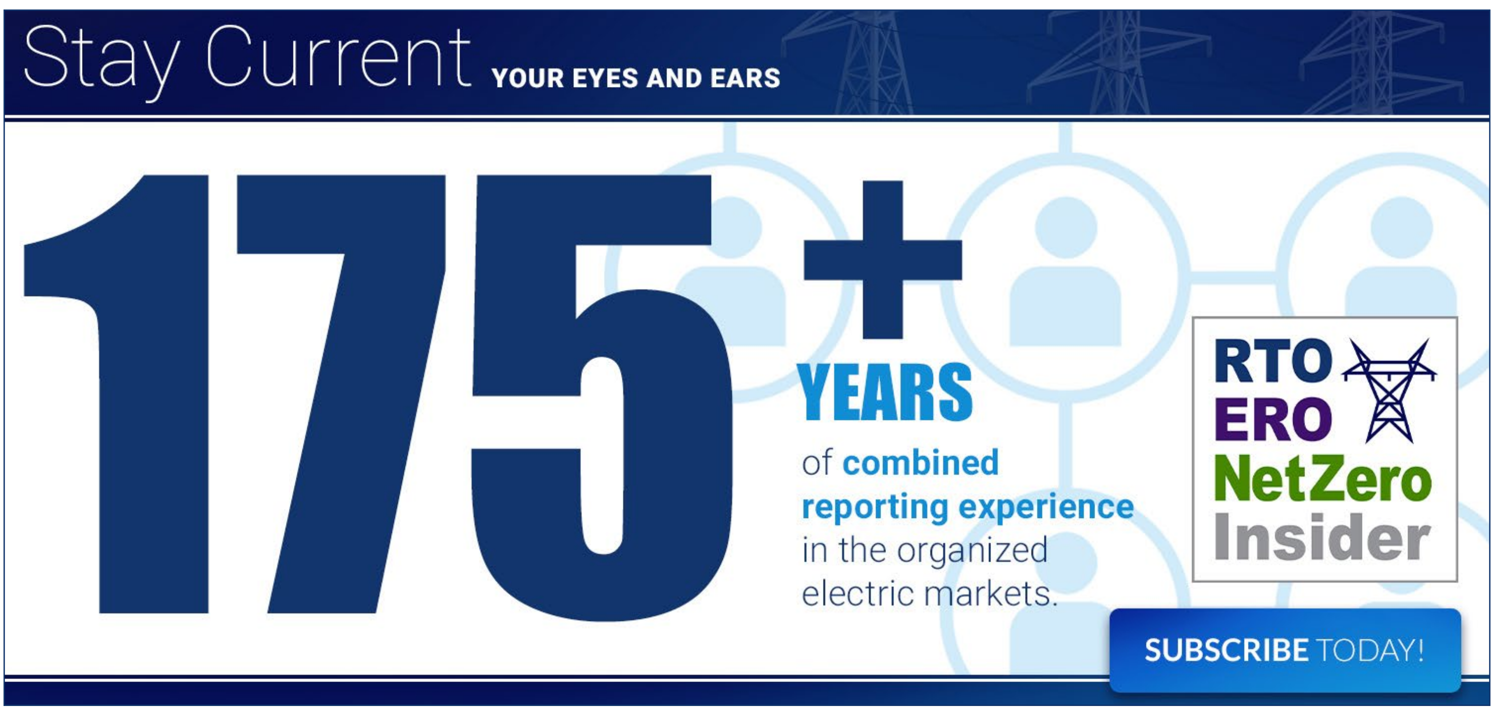
MISO said load for the month peaked at 115 GW on Sept. 5 during a hot weather alert for MISO Midwest. The monthly peak registered higher than last September's peak of 107 GW. Otherwise, load averaged 77 GW, above last year's 75-GW average and climbing incrementally from September 2021's 74-GW average.

Average daily outages for the generation fleet over September were the lowest they've been in four years. MISO recorded an average 39 GW in daily outages, down from last September's 48 GW in outages.

Since September 2020, coal has lost a small amount of ground in the energy mix, while natural gas-fired generation has gained ground. Natural gas has reached 40% of the energy mix, while coal has shrunk to 31%, flip-flopping 2020's mix, which saw coal leading at 34% and natural gas at 31%. ■



A comparison of the Sept. 2023 and Sept. 2020 MISO fuel mix | *MISO*



NYISO News

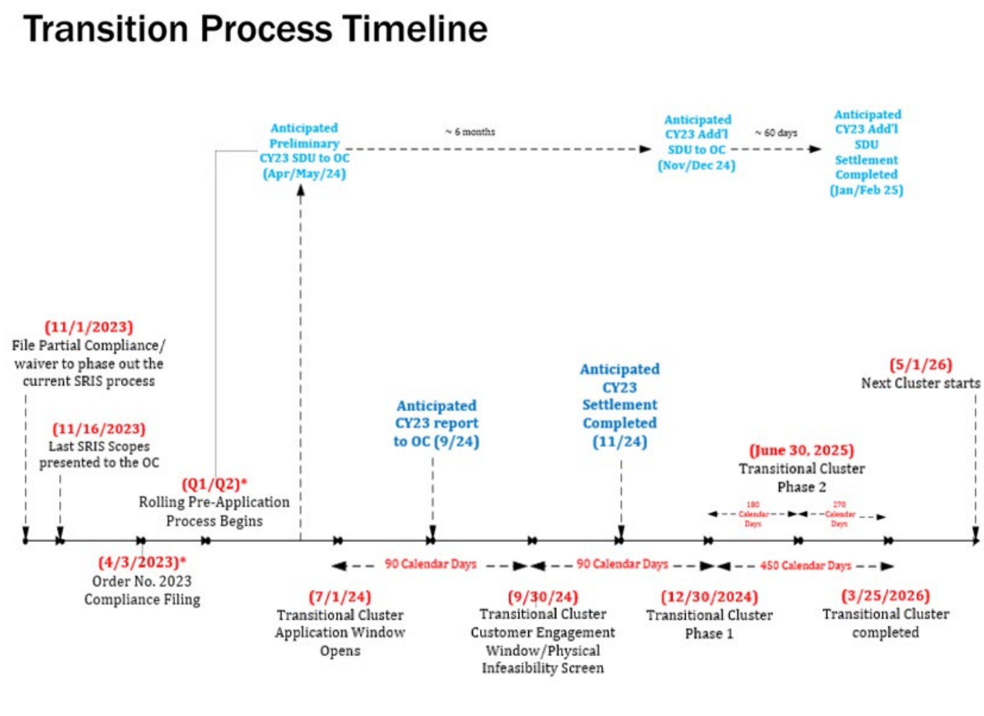
NYISO Stakeholders Question Proposed Interconnection Timelines, Deposit Rules

By John Norris

RENSSELAER, N.Y. — Stakeholders at NYISO's Nov. 4 Interconnection Issues Task Force meeting expressed reservations about the grid operator's proposed interconnection queue rules, citing concerns over the length of time to make project decisions and deposit requirements.

Following the ISO's *presentation* of proposed study deposits and withdrawal penalties, Troutman Pepper partner Stu Caplan, who represents the New York Transmission Owners, highlighted the uncertainty surrounding the transition to NYISO's proposed phased cluster approach. "There's a big variable that we don't know the answer to yet, the feasibility of the timeframes to complete the [interconnection] studies," he said.

NYISO's proposal to comply with FERC Order 2023 would give developers a seven-day window after each phase to decide whether to proceed or withdraw from the queue based on results from the preceding study phase.



Revised interconnection transition process timeline, adjusted per FERC compliance extension | *NYISO*

The ISO proposes to charge interconnection applicants a non-refundable $10,000 fee, as well as a one-time study deposit ranging from $100,000 to $250,000 based on the size of the proposed project. For capacity resource interconnection service-only projects, the deposit would be $50,000. Additionally, in lieu of regulatory milestones, developers would be required to make commercial readiness deposits to progress through the queue phases, with amounts escalating at each stage: depositing $4,000/MW to enter Phase 1, depositing the greater of either the Phase 1 deposit or 20% of the cost estimate determined in Phase 1 to move into Phase 2, and 100% of a project's cost estimate to move out of Phase 2.

NYISO also outlined penalties for developers who withdraw from the queue: up to 100% of their study deposit, plus 20% of the Phase 2 deposit if they withdraw during the decision period at the end of Phase 2.

Reid Wagner, a clean energy markets analyst with the Alliance for Clean Energy New York, said the ISO's proposed timelines are too short. "Seven days could be hard for some companies, particularly international ones, to secure the funding in that short period of time," he said.

ISO attorney Sara Keegan responded that developers would "have ample time to get their ducks in a row" and make decisions about whether to move a project forward through the queue. Project cost estimates would be available "well before the seven-day trigger," she said.

Wagner then asked if the ISO would consider conducting a "harm test" at the end of each phase, as currently done by MISO, to "test how much harm a withdrawn project has caused to the other queued projects."

Keegan responded that NYISO is not considering a harm test akin to MISO's. "It is perhaps overly complicated, and we feel like that would make it incredibly difficult to administer, since we would end up needing a whole department to administer withdrawal penalties," she said.

Stakeholders also expressed frustration with NYISO's initial plan to accept only cash for study deposits, rather than allowing the use of credit.

Saad Syed, grid and interconnection manager with OW Ocean Winds, argued for flexibility, saying, "putting up much money in cash in such short intervals seems very difficult, on top of the withdrawal penalties that may occur. So, I strongly recommend using at least an ability to use letters of credit for [these deposits], since otherwise it might become untenable."

Echoing this sentiment, Abhishek Josh Ghosh, associate director with Cypress Creek Renewables, recommended that NYISO draw insights from PJM, which allows letters of credit in its processes. "It would be nice to have some flexibility in posting these deposits," he said.

Thinh Nguyen, NYISO senior manager of interconnection projects, acknowledged these concerns and committed to revisiting the payment options. "We are still considering whether a letter of credit is another option. But as you are aware, when we receive letters of credit, that means we have to do some kind of credit check on that entity," he said. "That's why we want to make sure that whatever the process we want to use is able to support and meet the very tight defined timelines."

FERC last month extended the Order 2023 compliance deadline from Dec. 5 to April 3, 2024. (See *FERC Extends Interconnection Queue Compliance Deadline*.)

Despite the extension, Keegan informed the IITF that NYISO still intends to submit a partial compliance filing by Dec. 1. (See *NYISO Plans Early November Filing for Partial Order 2023 Compliance*.) The IITF will reconvene Nov. 14. ■

PJM Recommends $5B in RTEP Transmission Projects

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM has proposed around $5 billion in transmission upgrades to address data center load growth and generation deactivations primarily in the northern Virginia region identified in the third window of the 2023 Regional Transmission Expansion Plan (RTEP). (See PJM Shortlists 3 Scenarios for 2022 RTEP Window 3.)

PJM Senior Vice President of Planning Ken Seiler told the RTO's Transmission Expansion Advisory Committee (TEAC) the proposal would meet energy needs through the 2027/28 delivery year while providing long-term benefits to the grid by facilitating interconnection of new resources.

"It's well-documented that there's going to be a lot more transmission required as we go through the energy transition, and this is an area that's a prime example of that," he said. "We're going to need a number of projects to meet those needs."

The proposal largely tracks the 500-kV combination proposal PJM presented during the Oct. 3 TEAC meeting, which would build new 500-kV lines from northern Virginia out to the Peach Bottom substation to the northeast, the 502 Junction substation to the northwest and the Morrisville substation to the south.

PJM created the combination proposal by merging portions of the 72 proposals it received in the competitive planning process and directing some upgrades to infrastructure to address needs not resolved by any of the proposals. The final product includes work assigned to Dominion, FirstEnergy, Exelon, LS Power, NextEra, Transource and the Public Service Enterprise Group (PSEG).

Ken Seiler, PJM | © RTO Insider LLC

The largest portion of the work is centered on "Data Center Alley" near Dulles Airport in Loudoun County, with over $1 billion of projects assigned to Dominion in that region. The scope includes two new 500/230-kV substations and upgrades to the Mars substation. PJM's Sami Abdulsalam said the lines between those substations would form a ring around Data Center Alley to feed energy into the facilities.

The proposal also includes upgrades to several 230-kV lines and substations in Virginia running between the Dooms and Gordonsville substations, as well as to the Summit D.P.-Ladysmith CT 230-kV line. The work also includes a 500-kV line from the Otter Creek facility to the High Ridge substation.

Abdulsalam said the RTEP window includes a significant number of deactivations, including the 1,295-MW Brandon Shores generator outside Baltimore, Md. Given the lack of resources in the interconnection queue to replace Brandon Shores, new lines will be needed to prevent reliability issues in the Baltimore Gas and Electric (BGE) zone, he said.

"If the transmission is delayed, something will have to give. Either load needs to be dropped ... or some generation shows up. We don't currently have any generation in the queue" that would come online in time, he said.

About 11 GW of generation is expected to retire within the Window 3 time frame, which extends to 2028, while 7.5 GW of new data center load will come online.

The proposal is expected to cost about $4.9 billion based on the cost estimates included in project submissions, while the independent estimates of those projects amount to $5.4 billion.

Consumer Advocates Frustrated

A second first read of the proposal is scheduled for the Dec. 5 TEAC meeting, after which PJM plans to bring the recommendation to the Board of Managers for approval.

Greg Poulos, executive director of the Consumer Advocates of PJM States (CAPS), said advocates had been frustrated when previous RTEP windows were approved by the board in July with little time after the second read for stakeholders to submit comments.

"There was significant frustration about the time given after the second read and what is the purpose of a second read," he said.

Sami Abdulsalam, PJM | © RTO Insider LLC

Philip Sussler, of the Maryland Office of People's Counsel (OPC), said the RTEP process could be improved by creating a clearer way for comments to be submitted and for more documents to be public. Several members of the public requested information about how to write letters to the Board of Managers during the meeting.

Residents who live along the proposed pathways questioned whether several aspects of the work would require new rights of way and expressed doubt about the feasibility of multiple transmission owners requiring certificates of public convenience and necessity (CPCNs). Maryland ratepayers also questioned why needs primarily in Virginia were being solved with transmission buildout across Maryland.

PJM's Augustine Caven said staff considered several factors in forming the proposal, including siting and permitting challenges. Other factors include cost containment provisions, constructability, outage coordination, development on new versus disturbed land and scheduling risks such as land and material procurement.

"PJM recognizes the need for working the permitting process, the regulatory process in four states and that's something that we'll definitely have to tackle ... but I think the idea here is to move forward with those conversations as quickly as possible and recognizing that it will be a parallel process trying to get the permitting in all four states," Caven said.

PJM said that much of the transmission work to the west would be brownfield, while the majority in the east would require new land or expanded rights of way. ■

PJM MIC Briefs

PJM Sets Deadline for 2025/26 Capacity Auction Participation

VALLEY FORGE, Pa. — Generators that plan to come online by the start of the 2025/26 delivery year will have until Dec. 12 to notify PJM of their intent to participate in the Base Residual Auction (BRA) for that year, slated for June 2024.

PJM's Pete Langbein *told* the Market Implementation Committee on Wednesday that resources that do not notify the RTO by Dec. 12 will not be permitted to participate in the BRA; those that do will be required to ultimately enter an offer.

The requirement is one of several prospective changes to the capacity market that PJM has filed at FERC following the Critical Issue Fast Path (CIFP) process that concluded in October; if the filing is not approved, the notification process will be the same as in past years, with no firm requirements. (See *PJM Files Capacity Market Revamp with FERC*.)

Langbein said that if a planned resource notifies PJM that it will be participating in the auction, any capacity that it does not offer cannot be used in that delivery year, including through Incremental Auctions (IAs). He gave the example of a generator that could offer 100 MW into the auction entering in 80 MW. That resource would not be able to offer the remaining 20 MW into subsequent IAs for that delivery year.

An information session will be held Nov. 8 to go over the template that generation owners will be asked to submit to PJM to make the notification. Questions can be submitted to *rpm_hotline@pjm.com*.

Manual Revisions for New Performance Assessment Interval Triggers Endorsed

The MIC endorsed conforming *revisions* to Manuals 11 and 18, which sets the capacity market rules, to codify changes to the triggers initiating a performance assessment interval (PAI).

The changes were approved by the Members Committee in May and signed off on by FERC on July 28. (See *FERC Approves PJM Change to Emergency Triggers*.)

Generators with a capacity commitment are required to meet or exceed their obligation during a PAI or face penalties, which in the case of the December 2022 winter storm amounted to about $1.8 billion.

Pete Langbein, PJM | © *RTO Insider LLC*

The changes would set two conditions for triggering a PAI, with the first requiring a primary reserve shortage paired with any one of the following: a voltage reduction warning and reduction of noncritical plant load; manual load dump warning; maximum generation emergency action; or curtailment of nonessential building load.

The second condition requires a deploy-all-resources action, manual load dump action, voltage-reduction action or load-shed directive.

The MC approval of the trigger changes also included modifications to the penalty structure that generators are subject to, but PJM's Board of Managers included only the trigger changes in the FERC filing. Changes to the penalty structure are included in the CIFP proposal submitted to the commission Oct. 13. (See *PJM Board Rejects Lowering Capacity Performance Penalties*.)

Stakeholders Endorse Issue Charge on DR Energy Market Parameters

The MIC endorsed an *issue charge* to explore creating new parameters that demand response resources can enter into the energy market. (See "Voltus Withdraws Issue Charge on DR Offer Parameters" *PJM MIC Briefs: Sept 6, 2023*.)

Voltus Vice President of Energy Markets Emily Orvis said DR generators currently lack equivalents to some of the parameters thermal generators can include in their offers, namely maximum run times and minimum times between deployments. Adding those parameters would be particularly beneficial for consumers that can shift building heating and cooling away from peak grid periods, she said. While that energy use could be deferred, temperatures would need to be regulated after some time and a recovery period might be needed before load could be curtailed again.

Resources currently can offer themselves into the market for specific times of day, but that must be manually done each day and is not flexible. If a resource can only be available for two hours, it would have to choose two hours ahead of time and mark itself as available. Orvis said creating a new parameter would give PJM dispatchers flexibility to call on short-duration DR resources when they would be most economical.

Much of Wednesday's discussion focused on educating stakeholders on how any changes to energy-only DR resources may impact accred-

PJM News

iting corresponding capacity resources under the effective load-carrying capability (ELCC) methodology.

Langbein said economic DR participating in the energy market is treated as a separate resource from load management in the capacity market, and the parameters of one would not affect the other.

Calpine's David "Scarp" Scarpignato pushed for discussion of any potential interactions with ELCC accreditation to be included as an educational item to check for unintended consequences.

Independent Market Monitor Joe Bowring argued that the issue charge should allow for changes to the capacity rules for DR if any interactions are identified during the education process and said market rules should reflect differences between resources.

"The issue is to ensure that any such demand-side resource with limited response times should not be allowed to be a capacity resource because the proposed limits are not consistent with the obligations of demand-side capacity resources," Bowring said.

Orvis said her priority is to keep the discussion focused on changes to the energy market side, but she acceded to adding education on ELCC interactions to the in-scope portion of the issue charge.

EE Resources Concerned About Issue Charge on Market Participation

PJM presented a first read of a *problem statement* and *issue charge* to consider how energy-efficiency resources participate in the capacity market.

Langbein said EE was introduced to the capacity market about a decade ago without any subsequent consideration of how it is functioning, and staff feel it could use a fresh set of eyes.

The work timeline was set at nine months, with the idea that if changes are identified that could be implemented quickly, they could be made in time for the 2025/26 BRA. Langbein said staff aren't trying to rush any changes and if stakeholders desire more time, the work could continue longer.

Several EE market participants expressed concern about the wide range of the issue charge and urged PJM to include more clarity on the scope. They also sought assurance that there would be adequate time for any changes to be understood by all stakeholders and for them to make any necessary changes to their offers for the next capacity auction.

Luke Fishback of Affirmed Energy said setting the scope of the issue charge to be so broad makes it difficult for EE market participants to evaluate where the discussion may go and how it may affect their operations, creating a chilling effect. He suggested that a phased approach would be preferable to allow any changes that can be made ahead of the auction to be considered while minimizing market disruption before more substantial changes.

"Let's give adequate time and space for the exercise of evaluating a resource and, in the near term, make sure that market participants can make investments that support their class of resources," he said.

The problem statement says PJM's capacity market has seen significant changes since EE was introduced. EE clearing the capacity auction has grown from 78.1 MW in DY 2011/12 to 7,668.7 MW in the 2024/25 BRA, making up about 5% of the capacity procured.

The issue charge would "evaluate EE participation and consider opportunities to eliminate ambiguity regarding what qualifies as an EE resource and ensure the energy saving attributed to the EE resource is nonbiased, accurate and reasonably consistent across providers" and make any changes toward those ends.

Other Committee Business

Stakeholders endorsed an *addition* to Manual 11, which relates to energy and ancillary services market operations, to define the amount of energy intermittent resources with a capacity commitment are obligated to enter into the day-ahead market. Resources should enter either the larger of their economic maximum value or their expected output based on hourly forecasts. Resources could use PJM's forecast to estimate their availability or substitute their own forecast so long as it has a higher confidence interval.

The committee also endorsed a quick-fix *solution* brought by PJM seeking to revise references and typos in Manual 11. The quick-fix process allows an issue charge and solution to be voted on concurrently. ■

— Devin Leith-Yessian

PJM News

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Endorse Changes to 300-MW Load Loss Criteria

VALLEY FORGE, Pa. — The Planning Committee endorsed *revisions* to Manual 14B to specify that the 300-MW load loss to be considered in transmission contingency analyses applies only to losses impacting a large number of customers.

PJM's Stan Sliwa said that the change is meant to address the growth of data centers and other large load customers, which can cause a single large customer to surpass the 300-MW threshold in PJM's reliability planning criteria.

The proposed manual changes specify that the requirement applied to load loss "impacting numerous customers" and states that the limit is not applicable to "contingencies impacting several customers that aggregate to 300 MW or higher."

The proposal would also grant PJM discretion to permit load loss above 300 MW on a case-by-case basis, which PJM Director of Operations Planning Dave Souder said is meant to build on the goal of targeting outages affecting a large area.

Transmission Expansion Advisory Committee

Two Generation Deactivations Being Studied

PJM is conducting reliability analysis of two generators that have filed deactivation notifications: the 844-MW H.A. Wagner generator, owned by Talen, and the 180-MW Warrior Run unit 1, owned by AES.

PJM's Perry Ng said a preliminary analysis found that the retirement of the Wagner plant, which can run on coal, natural gas, and oil, would cause reliability violations. Talen has requested to take the plant offline on June 1, 2025,

The study assumed the continued operation of Talen's 1,295-MW Brandon Shores coal plant, whose scheduled retirement is expected to require $786 million in transmission upgrades. (See "Brandon Shores Deactivation to Require $786M in Grid Upgrades," *PJM PC/TEAC Briefs: June 6, 2023*.) Both generators are sited in the Baltimore Gas and Electric transmission zone.

The Warrior Run retirement is not expected to prompt any reliability concerns, Ng said. He said the completed analysis of the 4-MW Trent generator deactivation request found no issues.

Supplemental Projects

FirstEnergy has *revised* its proposed solution to replace an aging transformer at its Homer City North 345/230-kV substation because the equipment won't be available for over a year beyond the desired in-service date in December 2023 due to backlogged procurement schedules. The original $6.6 million project would replace the transformer with a new unit rated at 691/854 MVA and install an auxiliary 230/23-kV transformer; the new proposal would use a higher rated 913/1,147-MVA transformer and drop the auxiliary component.

Commonwealth Edison *presented* a $24.1 million project to replace a 345/138-kV autotransformer and capacitor bank at its Des Plaines substation, where mechanical issues have caused the transformer to be taken out of service periodically. The project has an in-service date of Dec. 31, 2025.

PECO *presented* a $18.2 million project to rebuild two 96-year-old lines nearing their end of life: the 2.5-mile Plymouth Meeting-Flint 230-kV double circuit line and the Plymouth Meeting-Upper Merion 230-kV double circuit line. The Plymouth Meeting-Flint project has an estimated cost of $18.2 million, while the Plymouth Meeting-Upper Merion work has a $29.2 million cost. The projects also involve upgrades at the three substations.

Public Service Enterprise Group *presented* a $105.1 million project to construct a greenfield 69/13-kV substation, named Harlingen, in Hillsborough, N.J., to address rising loads at its Sunnymeade and Mount Rose substations. The substation would be cut into the Bennetts Lane-Montgomery 69-kV line and the Montgomery-Customer Sub 69-kV line. The work also includes the addition of a second 230/69-kV transformer at the Bennetts Lane substation and modifications to the buses at that facility.

Dominion has *updated* a $55 million project to interconnect a new substation, Germanna, to serve a data center complex in Culpeper County, Va., with a projected 124-MW load. The substation would be cut into the Cirrus-Gordonsville 230-kV line, with an in-service date of April 16, 2026.

AEP *presented* a $116.7 million project to rebuild 19 miles of its Marysville–Hyatt double circuit 345-kV line due to aging infrastructure, concerns of core corrosion and difficulty finding replacement parts. The utility stated that it has around 570 miles of "paper expanded/air expanded" line rated at 345-kV in its footprint which will need replacement over the next 20 years. The Marysville – Tangy line has experienced two "permanent" and three "momentary" outages.

AEP also presented a need for a serving a new 1,500-MW data center customer in New Carlisle, Ind. with a requested in-service date of Dec. 15, 2026. ■

— Devin Leith-Yessian

Mid-Atlantic news from our other channels

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NetZero Insider

BOEM Approves Coastal Virginia Offshore Wind

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PJM News

PJM OC Briefs

Stakeholders Endorse Winter Weekly Reserve Target

VALLEY FORGE, Pa. — The PJM Operating Committee on Thursday endorsed the RTO's *recommended* winter weekly reserve target (WWRT) for the upcoming season.

The figure is used to coordinate outages over the winter to mitigate load and forced outage uncertainty. (See "PJM Presents Recommended Winter Weekly Reserve Target Values," *PJM OC Briefs: Oct. 5, 2023*.)

PJM's Patricio Rocha Garrido said the study recommended values of 28% for December, 30% for January and 25% for February. All three months would have higher targets than last year's study, which had 21% for December, 27% for January and 23% for February.

The higher values are because of changes to the modeling of forced outages over the winter and the inclusion of data from December 2022's Winter Storm Elliott and the 2014 polar vortex. PJM had historically not included the polar vortex data because of a belief that it would not reflect conditions that the grid was likely to experience again, but it revised that practice following Elliott.

The WWRT is one of three components of the annual Reserve Requirement Study. The other two, the installed reserve margin and forecast pool requirement, were endorsed by the Markets and Reliability Committee during its Oct. 25 meeting.

PJM Presents Operations Assessment Task Force 2023 Report

PJM's Thinzar Aung *presented* the results of the Operations Assessment Task Force's 2023 winter study, which found that the RTO would have a reserve margin of about 17 GW under the conditions normally studied but would be short nearly 5 GW if the specific conditions during the December 2022 winter storm were to occur again.

No reliability issues were found for the base case under the preliminary 50/50 peak load analysis, though some re-dispatching and switching would be required because of local thermal or voltage violations.

A total of 181.1 GW of capacity is expected to be available in the study, with a 90/10 diversified peak load of 141.4 GW.

The single largest gas/electric contingency

Patricio Rocha Garrido, PJM | *© RTO Insider LLC*

would reduce available generation by 4.8 GW, the study found. Paired with 16.7 GW of generation outages assumed in the analysis, 5 GW of exports and 7.2 GW of demand response, that leaves a 16.8-GW reserve margin.

The low wind and solar scenario would reduce generation by 4 GW, leaving a 17.6-GW margin.

The Elliott scenario increases the generation outages to 46 GW, reduces demand response to 2.4 GW and assumes a net interchange of 2.8 GW in imports. In such a scenario, PJM would be short 4.8 GW of generation.

PJM's Chris Pilong said the Elliott scenario was designed to replicate the worst conditions seen during the storm. (See *PJM Recounts Emergency Conditions, Actions in Elliott Report*.)

"It underscores the need to be prepared and, from a generation perspective, do everything we can to chip away at that 46,000 MW of outages," he said.

Quick-fix Manual Changes to Transmission Facility Cut-in Process Approved

Stakeholders endorsed a quick-fix *proposal* to allow PJM to delay energization of a line with a cut-in ticket if the transmission owner has not submitted evidence that all required critical tasks have been completed and the data verified by the RTO. The quick-fix process allows an issue charge and proposed manual changes to be voted on side-by-side.

If the required data have not been received and verified by PJM by 11 a.m. on the day prior to the requested energization date, and extending the outage would not pose reliability concerns, the RTO will delay the in-service date by one day, which can be continued if the data continue to remain unavailable. PJM's Dean Manno said it takes staff about one day to verify the data.

Manno said critical tasks include submitting parameters such as ratings, impedance, telemetry for tie-lines and monitored priority.

The changes are expected to be brought to the MRC for an endorsement vote on Nov. 15.

Generation Winterization Requirements Endorsed

The committee endorsed *revisions* to Manual 14D: Generator Operational Requirements, which include a requirement for resources to prepare for winter conditions and expanded the winterization checklist.

Part of the manual's periodic review, the revisions also include several administrative and clarifying changes.

The checklist now prompts generation owners to assess safety hazards posed by snow and ice accumulation on wind and solar facilities, inspect commodities and resources that may be used in severe winter weather, and consider adding a "freeze protection operator" staff member to inspect critical equipment.

PJM's Vince Stefanowicz said generators can substitute PJM's checklist for a comparable list of their own.

Clarifying Revisions to Manual 10 Endorsed

The committee endorsed *revisions* to Manual 10 that would clarify that generators entering outages or their availability into eDART should report their full nameplate capability unless physically derated.

Stefanowicz said physical derates are permanent changes to a resource that reduce its maximum output, such as components being taken offline that reduce output without the expectation of replacing them. ■

— Devin Leith-Yessian

SPP Membership Elects Solomon, Dimitry to Board

Veterans Altenbaumer, Martin to Retire as Directors

By Tom Kleckner

LITTLE ROCK, Ark. — *SPP*'s membership elected Stuart Solomon and Irene Dimitry to three-year terms on its independent Board of Directors during last week's Annual Meeting of Members.

Current board member Liz Moore also was elected to serve a second term, having joined the board in 2020. All three selections are effective Jan. 1.

Solomon, who has more than 30 years of utility experience, is a familiar presence among SPP members. He served on the Members Committee during his 14 years as Public Service Company of Oklahoma's president before retiring from American Electric Power in 2019 as senior vice president of generation services. Solomon was at Central and South West Corp. when the company merged with AEP in 2000.

"One hundred percent he knows what he's getting himself into, which I love about Stuart," CEO Barbara Sugg said during the board's Oct. 31 meeting. "Yet, he's still excited about continuing to talk about [SPP members] and anything else."

"It's a very important time of transition in the electric utility industry, and SPP is well positioned to lead the ongoing evolution of the industry," Solomon said in a *statement*. "I'm excited to be part of such a dynamic and forward-thinking organization during this time."

Dimitry retired in 2020 as vice president of renewable energy at DTE Energy, where she led the launch and daily operations of the company's renewable energy business. She has more than 26 years of utility experience.

"The clean energy transition will bring many changes and innovations over the next few years," Dimitry said. "I look forward to working with management and stakeholders as SPP's regional role grows and evolves."

Solomon and Dimitry will replace long-time directors Josh Martin and Larry Altenbaumer. The two, who have almost 38 combined years on the board, are retiring at the end of December. (See "Board Search Underway," *SPP Board/Members Committee Briefs: July 24-25, 2023*.)

The board recognized Martin and Altenbaumer with honorary resolutions and standing ovations during the meeting, along with a dinner where they were joined by former SPP CEO Nick Brown and former director Graham Edwards. Brown and Edwards left during the COVID-19 pandemic and did not receive honorary fetes.

SPP's membership also approved 16 nominees to the 24-person Members Committee. All but two were incumbents; Google's Betsy Beck and Evergy's Kayla Messamore will begin three-year terms in January representing the large retail customer and investor-owned utility segments, respectively.

The small retail customer segment's seat remained vacant.

Texas' McAdams to Lead RSC in 2024

The Regional State Committee, comprised of state regulators from SPP's footprint, elected its leadership for 2024 by approving a committee's recommendations in a voice vote.

Texas' Will McAdams will serve as the RSC's president. He already chairs SPP's REAL Team, in addition to his day jobs on the Public Utility Commission and helping manage the family farm near College Station.

Referencing McAdams' leadership in guiding the REAL Team as it assesses SPP's current resource adequacy construct and makes policy recommendations, Sugg said, "If we've got the will, we can get this thing done, and I think we've got Will McAdams.

"I can't commend him enough," she added. "From the conversations I've had with people who were and from what I observed from somewhat of a distance. He just did a remarkable job and I'm so thrilled that we had his leadership involved in terms of moving this thing forward."

Minnesota's John Tuma will serve as the RSC's vice president and Nebraska's Chuck Hutchinson as its secretary and treasurer.

The RSC also considered two motions related to SPP's safe harbor criteria used to determine which project costs should be borne by the

Stuart Solomon | © *RTO Insider LLC*

From left: Western commissioners Thad LeVar (Utah), Eric Blank (Colorado) and Kevin Thompson (Arizona) observe the Regional State Committee meeting. | © *RTO Insider LLC*

SPP News

load-serving entities (LSEs) making long-term transmission service requests (TSRs). The safe harbor exempts LSEs from upgrade costs when a TSR meets the aggregate studies' waiver criteria, which include:

- Wind generation not exceeding 20% of designated resources;
- A minimum five-year term for designated network resources TSRs; and
- Designated resources not exceeding 125% of forecasted load.

The commissioners rejected the Cost Allocation Working Group's recommendation to eliminate the 20% wind criteria but approved its proposal to increase the resource limit from 125% to 100% plus the higher of summer or winter seasonal planning reserve margin plus 10%.

Future RSC Members Observe

Several potential future RSC members joined the table for an up-close look at how SPP stakeholders make the sausage: Colorado's Eric Blank, Utah's Thad LeVar and Arizona's Kevin Thompson.

Their three commissions would be eligible to appoint representatives to the RSC as SPP's RTO West is stood up and begins operations in 2026. The grid operator uses an outreach program when it anticipates additional states will become part of the footprint.

Mary Throne, who chairs the eligible Wyoming Public Service Commission, also has attended SPP meetings this year. The Wyoming commission is eligible to join the RSC.

Calling RTOs a "significant milestone in the western United States," LeVar said, "I appreciate the chance to watch this mature and useful process that happens here and I look forward to the tariff development that will happen between now and implementation of RTOs."

Thompson said Arizona is determining whether to join SPP's Markets+ "RTO-lite" day-ahead market or *CAISO*'s Extended Day-ahead Market (EDAM).

"There's a lot to learn," he said. "I'm here to learn, I'm here to absorb and to take in everything that I can to make sure that [at] the end of the day, our utilities are protected and that our consumers are protected."

Blank, who chairs the Markets+ State Committee comprised of western commissioners, jokingly suggested a bylaw change, saying he would prefer a president's title.

"I covet your title," he told RSC President Andrew French.

Naturally, almost every speaker then addressed the committee's leader as "President French" for the meeting's duration.

Lucas, Rew Update Stakeholders

Antoine Lucas, SPP's markets vice president, said during the quarterly stakeholder reports that the Integrated Marketplace set new records for maximum load (56.18 GW on Aug. 21), bettering the previous high of 53.24 GW set in July 2022, and renewable energy production (25.02 GW on Sept. 4). Wind accounted for 51.69% of the fuel mix at its peak Sept. 4.

Bruce Rew, senior vice president of operations, said load exceeded the 2022 record during 24 hours the week of Aug. 21.

Day-ahead prices and real-time prices both increased more than 35% from the second quarter to the third, Lucas said, a result of increased fossil fuel generation during late-summer calm days. Day-ahead prices were up from $24.17/MWh to $33.13/MWh and real-time prices went from $23.11/MWh $31.26/MWh.

The Marketplace has 331 participants.

Rew said SPP has received commitment letters from all nine utilities and Western Area Power Administration regions who want to be in SPP RTO West when it goes live, targeted for April 1, 2026. The commitment obligates them to reimburse SPP for development expenses if membership agreements are not executed in March 2026.

The western expansion will affect SPP's existing members in the Eastern Interconnection as changes will be made to the settlements system and all market participants will have to go through some activities, Rew said. He expects about 15 revision requests will come before the board and RSC in January and April.

Lucas, who is leading the Markets+ development, said the project is on schedule to meet its target date, but that staff and stakeholders are working to mitigate issues that could cause delays. The project team plans to vet funding proposals with the Finance Committee in February.

"We're spending more of our time focusing on areas where there are certain unique areas of western market operations that need slightly different market design to what we have here in the east," Lucas said, a nod to greenhouse gas restrictions, congestion rent allocation and mitigation pricing for hydro storage. ■

Company News

AEP Discloses SEC Subpoenas, Investigation

Company Says It's 'Cooperating Fully' Over Ohio HB6 Inquiry

By Tom Kleckner

American Electric Power has revealed it's been issued two subpoenas from the Securities and Exchange Commission (SEC) as part of an investigation into the company's involvement in Ohio legislation that eventually led to a politician's bribery conviction.

In its regular quarterly *10-Q disclosure filing* to the SEC on Nov. 2, AEP said it had received subpoenas from the commission in 2021 and 2022. The first subpoena requested documents related to the passing of Ohio *House Bill 6* and to the company's policies and financial processes. The second sought additional documents related to the investigation.

AEP said it is "cooperating fully" with the SEC's investigation and is discussing resolving the inquiry with the commission and "potential claims under the securities law."

"The outcome ... cannot be predicted and could subject AEP to civil penalties and other remedial measures," AEP said in the filing. "Management is unable to determine a range of potential losses that is reasonably possible of occurring, but management does not believe the results of this investigation or a possible resolution thereof will have a material impact on results of operations, cash flows or financial condition."

The Columbus, Ohio-based company said it "does not believe that AEP was involved in any wrongful conduct in connection with the passage of HB 6."

The legislation provided $1 billion in subsidies to a pair of coal plants in which AEP has a 43% stake and two nuclear plants. AEP lobbied for the bill's passage, which resulted in the federal indictment of Ohio House Speaker Larry Householder for his role in taking bribes from another in-state utility, FirstEnergy, to pass the legislation. Householder was convicted and imprisoned earlier this year. (See *Former Ohio House Speaker Householder Sentenced to 20 Years in Prison*.)

AEP executives did not address the 10-Q filing during its quarterly earnings conference call with financial analysts, who did not ask any questions about it.

The disclosure took a little shine off AEP's *reported* quarterly earnings of $954 million ($1.83/share). That was an improvement from the same period in 2022, when earnings were $684 million ($1.33/share).

AEP CEO Julie Sloat said the company continues to de-risk and simplify its business. She pointed to the *completed sale* of its 1,365-MW unregulated renewables portfolio that netted about $1.2 billion, and the sales processes for the company's retail and distributed resources businesses that remain on track.

AEP continues its strategic review of the *Transource Energy* joint venture with Evergy. Sloat said the review is expected to be completed before the year is up.

Sloat said the company's commercial load growth was up 7.5% year over year, attributing the vast majority of the increase to data centers in Ohio and Texas.

AEP's share price closed Friday at $79.72, a gain of $3.24 (4.2%) over the last two days of the week.

OGE Earnings Down

OGE Energy, parent company of Oklahoma Gas & Electric, also *reported* third-quarter results Thursday, delivering earnings of $241.9 million ($1.20/diluted share). That compared unfavorably with the same period a year ago, when earnings were $262.8 million ($1.31/diluted share).

Although earnings were down year over year from 2022, OGE CEO Sean Trauschke told financial analysts the "solid" performance was due to operational excellence. OG&E sent a new hourly peak on Aug. 21 during the height of the summer's heat, and did so without calling for public conservation, he said.

"Our system was designed, built and operated for conditions like we saw this summer, and I'm proud of our team for always meeting our customers' need for reliable and safe electricity, and always keeping affordability top of mind," Trauschke said.

The company's share price gained 75 cents after earnings were posted, closing Friday at $35.25. ■

AEP says it is "cooperating fully" with the SEC's investigation into the company's involvement with Ohio House Bill 6. | *Electric cat, CC BY-SA 3.0, via Wikimedia Commons*

Company News

Dominion Highlights Successful Offshore Wind Development on Q3 Call

By James Downing

Dominion Energy reported third-quarter earnings Friday, with executives focusing on why its offshore project is successful and on its business review that is nearing completion.

"Our fully regulated offshore wind project is on time and on budget and is expected to save customers more than $3 billion in fuel costs over the first 10 years of operation while creating hundreds of jobs and millions of dollars of local economic benefit," CEO Robert Blue said.

The Coastal Virginia Offshore Wind (CVOW) project is being built off the coast of Virginia Beach and is planned to have 176 turbines producing a nameplate capacity of 2.6 GW. The wind plant won final approval from federal regulators earlier in the week and saw the delivery of the first monopiles to a nearby port facility in late October. (See *BOEM Approves Coastal Virginia Offshore Wind*.)

"The next transport ship for monopiles is expected to be loaded at the factory later this month and delivered to the port in December," Blue said. "Also worth noting is that turbine blades and the cells remain on track with a fixed production schedule and mature existing manufacturing facilities."

The monopile delivery included a ceremony with politicians from across the spectrum in the commonwealth, with Blue noting the project has "bipartisan support" a few days before an election that could give the Republican Party control over both chambers of the legislature and the governor's office for the first time in years. The *polling* in the election shows a very close race.

The project has a priority position in the offshore wind supply chain, and Dominion has proven successful at getting approvals from the required regulators, Blue said.

The firm expects to complete CVOW by the end of 2026, and most of its $9.8 billion in costs are already fixed.

"We updated the project expected [levelized cost of energy] in our filing earlier this week to approximately $77/MWh, as compared to our previous range of $80 to $90," Blue said. "The decrease reflects updated and refined estimates around production tax credit, cost of capital and [renewable energy credit] values."

The project's total lifetime costs are still expected to come in well below the ceiling set by the legislature when it approved the development.

Dominion will have invested $3 billion into CVOW by the end of the year, and the rest of the $9.8 billion is 92% fixed, with just the costs of interconnecting the project to the transmission grid, some commodities such as fuel used for construction, and installation and project oversight costs yet to be nailed down, Blue said.

"We've been very clear with our team and with our vendors that delivery of an on-budget project is the expectation," he added.

Dominion has been in talks with counterparties to sell a minority share in CVOW to help raise the remaining equity; Blue said those talks have generated much interest.

"It's in the long-term best interest of our customers and shareholders that we make the right, not just the expedient, decision," Blue said. "A properly structured partnership with the optimal counterparty is an attractive option. But only if the terms of a potential transaction make sense for our customers and shareholders."

A decision picking a counterparty for the wind project is the last part of Dominion's ongoing business review, which has seen it sell its share of the Cove Point LNG project and exit the natural gas utility business, Blue said. The firm expects to make a choice in the next few months.

The review was launched after investors expressed worries about the firm's earnings, the Virginia regulatory model (which was revised early this year) and its balance sheet, Blue said.

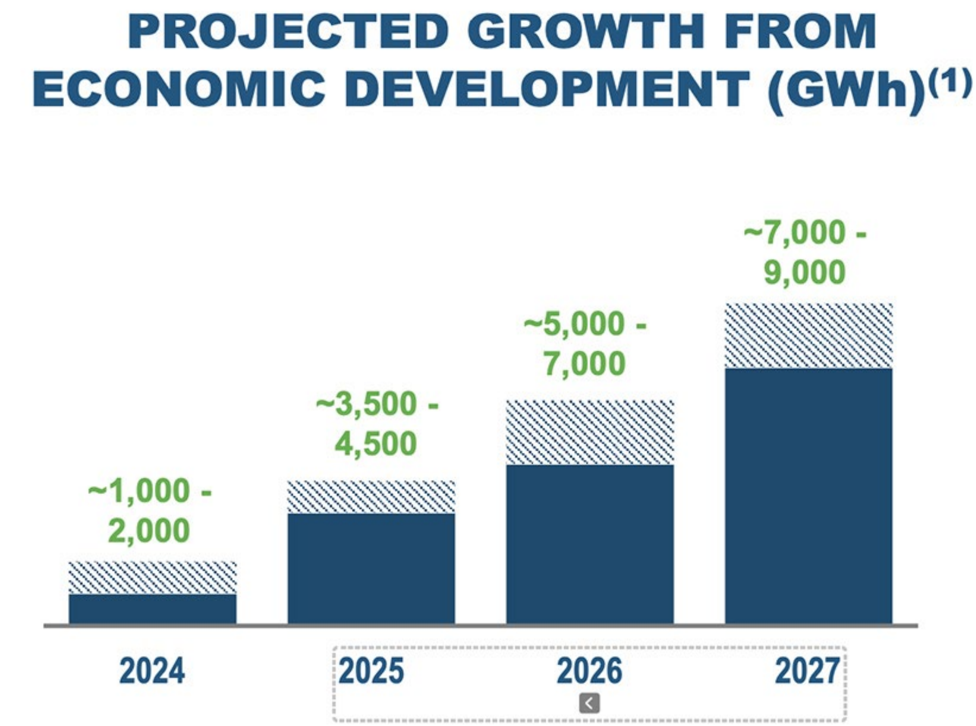
"The review must comprehensively and finally address the foundational concerns that have eroded investor confidence over the last several years," Blue said. "This can't be a series of partial solutions that leave key elements and risks unaddressed. That's how we've approached this top-to-bottom review." ■

Port of Virginia CEO Stephen Edwards, Gov. Glenn Youngkin (R), Virginia Secretary of Transportation Shep Miller, and Dominion Energy CEO Robert Blue at a ceremony celebrating the first delivery of monopiles to the utility's offshore wind project. | *Dominion Energy*

Company News

Duke Earnings Slip on Low Demand, but Long-term Growth Expected

By James Downing



A chart from the utility showing its projections for cumulative annual load growth through the middle of this decade. | *Duke Energy*

Duke Energy saw its third-quarter earnings drop from a year ago as it dealt with mild weather and low demand from industrial customers, but executives told analysts Thursday those trends should turn around.

Earnings per share fell to $1.59 on the quarter, compared to $1.81 in the summer of 2022. On top of a return to growing demand, Duke CEO Lynn Good also highlighted plans to transition its utilities around the country to cleaner resources.

"With the closing of the commercial renewable sale last month, our portfolio repositioning is completed," Good said. "We are now a fully regulated company, operating in some of the fastest-growing and most attractive jurisdictions across the U.S." (See *Duke Sells Distributed Renewable Business to Arclight*.)

The firm's biggest market is the Carolinas, where it dominates the utility space. The North Carolina Utilities Commission (NCUC) recently approved new rates for Duke Energy Progress and has a pending case before it for Duke Energy Carolinas (DEC) that Good said should wrap up in the fourth quarter.

The NCUC approved a rate base of $12.2 billion and $3.5 billion in investments for the firm, while a settlement pending in DEC's case would set its rate base at $19.5 billion and approve $4.6 billion in funding. While the firm has several subsidiaries serving the Carolinas, it plans their system jointly, and it filed the latest iteration of its resource plan with the two states in August.

"The single unified resource plan for the Carolinas is designed to meet the needs of this growing region spurred by rapid population growth and significant economic development activity," Good said. "The plan maintains an all-of-the-above strategy with a diverse deployment of additional resources, including renewables, battery storage and natural gas, as well as energy efficiency and demand-side management."

Sales volumes are down 1.2% on a rolling 12-month basis, with industrial customers saying they are scaling back their business slightly because of uncertainty in the economy, said CFO Brian Savoy.

"Most are describing the pullback as temporary, and there's optimism that it's about to turn around in mid- to late 2024 and into 2025," Savoy said. "We continue to see strong customer growth from population migration and robust economic development, giving us confidence in growth over the long term."

Textiles and the paper industry have been hit by slowdowns, but other industries are facing issues with the supply chain, labor and interest rates that have contributed to lower demand, Good said. Others have built up a significant inventory of product and have cut back on production to sell off the excess.

Residential demand had been impacted by the trend of returning to work after the pandemic, but that is over, Good said. Lingering residential demand weakness will be offset as Duke moves to decoupled rates in North Carolina next year, Savoy said.

"We've got customers sort of working through the macro-term trends here in the short term," Good said. "But over the long term, we continue to see this economic development being incredibly strong."

Economic development projects coming online next year add up to 1,000 to 2,000 GWh of new demand, with Duke expecting to add 7,000 to 9,000 GWh by 2027, a growth rate of between 0.5 and 1%, Savoy added. That load growth is reflected in Duke's plans to expand its generation in the Carolinas.

"We see a need for additional megawatts in the Carolinas really driven in large measure by population growth, economic development and reserve margin," Good said.

Populations are also growing in the other states in Duke's footprint. The utility is planning to start transitioning its Indiana utility away from coal-fired generation to rely more on natural gas and renewables, Good said. Duke expects to file certificates to build new generation in the Hoosier State in the next several months.

The plan in North Carolina also calls for new natural gas. One analyst asked Good about potential pushback against new fossil infrastructure.

"We believe what we've put forward is a very balanced, all-of-the-above strategy that provides the right balance between reliability, affordability and increasingly clean, which is our commitment to the state," Good said. "So, we think all of those elements will be closely reviewed and evaluated as part of the process in front of the commission." ■

Company News

Summer Heat Drives Strong Entergy Earnings

Entergy said the summer's record-setting temperatures led to "very strong" financial results during the third quarter, providing an opportunity for the company to flex its investment plans.

CEO Drew Marsh told financial analysts during the company's quarterly earnings call Nov. 1 that the system surpassed previous peak demand records on 13 days during July and August.

"Our generation portfolio covered our customer demand and we operated well within our reserve margins," Marsh said, adding that Entergy's nuclear fleet operated with a 99% capacity factor.

The call came two days after the New Orleans-based company *reached an agreement* to sell its natural gas distribution business for $484 million to Bernhard Capital Partners, a Baton Rouge, La., private equity firm. Marsh said Entergy will use the proceeds to reduce debt and support its capital needs.

Marsh also discussed a recent $142 million *settlement in principle* between Entergy subsidiary System Energy Resources Inc. (SERI) and Arkansas regulators that resolves several pending cases. The agreement will result in SERI refunding Entergy Arkansas the settlement's total, inclusive of about $50 million already received by the operating company from another Entergy affiliate.

SERI generates and sells nuclear power, primarily through its 90% ownership and leasehold interest in Grand Gulf. Regulators in Entergy's four-state footprint have long complained about SERI's practice of billing ratepayers for the costs of Grand Gulf's sale-leaseback renewals under a unit-power sales agreement between the subsidiary and Entergy's operating companies.

Entergy *reported* third-quarter earnings of $667 million ($3.14/share), an improvement from the same period a year ago, when earnings came in at $561 million ($2.74/share).

The company's share price closed at $97.74 Wednesday, a gain of $2.15. ■

— Tom Kleckner

Summer's extreme heat has boosted Entergy's earnings. | *Shutterstock*

Company News

Exelon Q3 Earnings Call Links Transmission Expansion to Rate Cases

Utility Selected for $850M in Transmission Upgrades from PJM's Mid-Atlantic Solicitation

By K Kaufmann

Exelon utilities have scored some big wins in the past few weeks, beginning with PJM's selection on Oct. 31 of project proposals for a *competitive transmission solicitation*, including an $850 million package of projects for the utility and its subsidiaries, CEO Calvin Butler announced during a Nov. 2 third-quarter earnings call.

The package includes projects for Baltimore Gas and Electric (BGE), PECO, Pepco and Delmarva Power & Light, with completion dates scheduled for 2029 and 2030, timeframes that "extend beyond the current guidance range," Butler said. "It provides another good indication of the trends in place and degree of work that the grid will require, well into the future."

Other forward-looking developments include Exelon's active role in two of the seven regional hydrogen hubs the Department of Energy announced Oct. 13, Butler said. Commonwealth Edison (ComEd) is part of the team working on the Midwest hub, while PECO and Pepco will be similarly involved in the mid-Atlantic hub. (See *DOE Designates Seven Regional Hydrogen Hubs.)*

ComEd and PECO also were named to receive $50 million and $100 million, respectively, as part of DOE's $3.46 billion Grid Resilience and Improvement Program, announced Oct. 18. A total of 58 projects received grants from the program, which is funded by the Infrastructure Investment and Jobs Act. (See *DOE Announced $3.46B for Grid Resilience, Improvement Projects*.)

ComEd will use the money to deploy "next-generation technologies" that will support wider adoption of electric vehicles and solar, while PECO's grant will go to grid hardening in "vulnerable areas" of the utility's service territory to help keep the power on during extreme weather events.

"The federal support is critical to supporting an affordable and equitable transition," Butler said. "The need for transmission expansion, the investment in new energy supply and the ever-increasing need for more resilient grids all highlight the impact that an economy that is increasingly dependent on electricity will have on our investment plan.

"The energy transformation will last decades, not years, which is why we are confident that investment opportunities will continue to strengthen and lengthen our rate base growth."

During Exelon's Q3 earnings call, CFO Jeanne Jones highlighted Delmarva Power's $40 million East New Market to Cambridge grid upgrade project on Maryland's Eastern Shore. | *Delmarva Power & Light*

The PJM selection is a case in point. The grid operator opened the window for the solicitation to expand transmission to meet new demand being created by the rapid expansion of data centers in Northern Virginia, as well as the impact of the pending retirements of fossil fuel generation, such as Maryland's Brandon Shores coal-fired plant.

While Butler did not provide details on the Exelon projects, PJM said it is recommending a mix of new substations and transmission as well as upgrades to existing facilities. The recommendations will go back to PJM's Transmission Expansion Advisory Committee before being sent to the Board of Managers for final approval.

Looking at local grid improvements, Chief Financial Officer Jeanne Jones highlighted a recently completed grid upgrade on Maryland's Eastern Shore, the 11-mile East New Market to Cambridge project, which installed new state-of-the-art steel poles to bolster local reliability. The new poles can withstand 120-mph hurricane force winds, she said.

Tackling Multiyear Rate Plans

The connection between transmission buildout, the energy transition and Exelon's rate base was a central theme throughout the call, as Butler and Jones gave a rundown of the six rate cases the company's utilities have before regulators in Illinois, New Jersey, Maryland, Delaware and the District of Columbia.

In ComEd's rate case, a recent proposed order from an Illinois administrative law judge (ALJ) recognized "that meeting the ambitious electrification and decarbonization goals set by [the state's] groundbreaking *Climate and Equitable Jobs Act* will require ComEd to make significant investments," Butler said.

But the ALJ set a return on equity below the national average, he said. "It does not allow for prudent capitalization of the business."

According to Butler, a recommendation from staff at the Illinois Commerce Commission (ICC) set an 8.9% rate of return, which the ALJ upped to 9.28%. ComEd's proposal calls for a 10.5% rate of return in 2024, rising incrementally to 10.65% in 2027, according to a *report* in Crain's Chicago Business.

A final order is expected in December, and ComEd will continue to make its case before the ICC, Butler said. Jones noted that the ComEd filing is its first run at a multiyear rate plan and framed the ALJ's proposed order as "just another data point in the process," given the number of variables at play in multiyear plans.

Four of the six rate cases — for BGE, Pepco Maryland, Pepco DC and ComEd — are for first-time multiyear plans, she said.

The Numbers

Butler noted that despite a mild winter and late summer storms with 110-mph wind gusts that knocked out power to 1.3 million Exelon customers, the utility's earnings were still on track with its 2023 predictions.

The utility's third quarter GAAP net income was $700 million ($0.70/share), while non-GAAP adjusted net income was $671 million ($0.67/share).

Butler said the utility is narrowing its guidance for 2023 as a whole to $2.32 to $2.40/share. ■

Company News

PSEG Reports Q3 Earnings, Infrastructure Investment Plans

By James Downing

Public Service Enterprise Group (PSEG) on Oct. 31 reported that third-quarter earnings were up to $139 million, compared to $114 million for the same period last year, and executives laid out their plans for infrastructure investing on a call with analysts.

PSEG's main subsidiary, Public Service Electric and Gas, "invested approximately $1 billion in capital spending during the third quarter, bringing the year-to-date spend to $2.7 billion," said PSEG CEO Ralph LaRossa. "For the full year 2023, capital spend is expected to total $3.7 billion, slightly higher than our original plan of $3.5 billion, ahead of scheduled execution on our Clean Energy Future-Energy Efficiency and Infrastructure Advancement Programs. This work is helping our customers to save energy and lower their bills, upgrading the 'last mile' of our system, as well as adding new electric infrastructure due in part to increasing EV penetration."

PSEG has been working to improve the predictability of its business by selling off its fossil generating assets to ArcLight Capital Partners early last year and exiting the offshore wind development business early this year.

"We have helped to secure the financial viability of critical, important New Jersey energy assets with the decision to retain our carbon-free baseload nuclear fleet, enhanced by the revenue stability of a production tax credit (PTC) that begins January of 2024," LaRossa said.

PSEG President and CEO Ralph LaRossa | *PSEG*

The federal PTC for nuclear is in place for a decade, giving PSEG enough security that it can execute its five-year capital investment program without issuing new equity or selling any assets, he added.

PSEG is putting some of the extra money back into those nuclear plants, as well, with plans to transition its boiling water reactor at Hope Creek from an 18- to a 24-month refueling cycle, LaRossa said.

The firm is waiting for final approval on a $447 million transmission project that it bid into a PJM solicitation last year, with the RTO's board expected to vote on it in December, LaRossa said.

"We intend to leverage our considerable transmission skills in similar opportunities that arise," he added.

The utility also reported success in expanding efficiency efforts under the conservation incentive program that has been in place since 2021. The program limits the impact of weather and other sales' variances on the firm's earnings while letting it earn money by promoting efficiency to both its electric and gas customers, said CFO Daniel Cregg.

"To give you some perspective on how strong the demand for energy efficiency is: Consider that PSE&G now sells more energy-efficiency solutions in a single month than we did in an entire year just a few years ago," LaRossa said.

The utility is also just over halfway done rolling out new smart meters, with 1.3 million deployed out of a plan for 2.3 million, LaRossa said. ■

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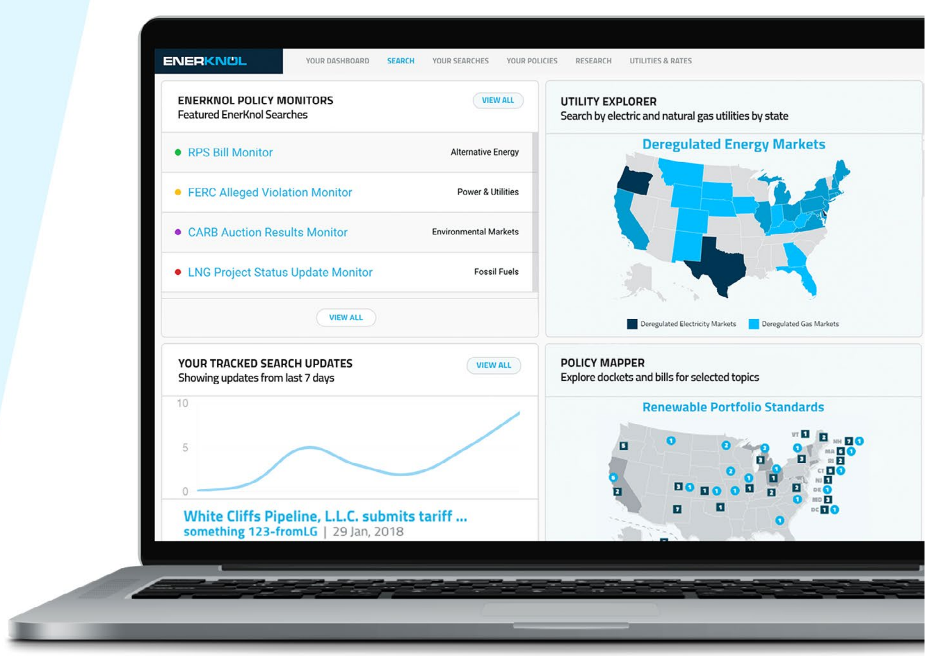


Company Briefs

Entergy to Sell Natural Gas Business to Bernhard Capital Partners

Entergy last week announced it is selling its natural gas distribution business to Bernhard Capital Partners for $484 million.

The utility is facing pressure from regulators to invest more in renewable energy and harden its grid, particularly after hurricanes in 2020 and 2021 caused hundreds of millions of dollars in damage to transmission lines, utility poles and other infrastructure.

Entergy hopes to finalize the sale by mid-2025 and is pending approval from the Louisiana Public Service Commission and the New Orleans City Council, among others.

More: *Nola.com*

Toyota Doubles Investment at North Carolina Battery Plant

Toyota last week said it will invest an additional $8 billion in the hybrid and EV battery factory it is constructing in North Carolina, more than doubling its prior investments and expected number of new jobs.

The plant will serve as Toyota's epicenter of lithium-ion battery production in North America and will be a key supplier for a Kentucky-based plant tasked with building its first U.S.-made electric vehicles, the company said.

Toyota's fourth and largest investment in the facility brings its total investment to about $13.9 billion to help meet its goal of selling 1.5 million to 1.8 million electric or hybrid vehicles in the U.S. by 2030.

More: *The Associated Press*

BP to Buy $100M Worth of Tesla Chargers

BP last week announced it will spend $100 million buying Tesla ultrafast chargers to build out its "BP pulse" network in the U.S.

The company said it will begin installing the chargers next year at its BP and Amoco gas stations, AMPM and Thorntons convenience stores, and TravelCenters of America truck stops, as well as at large "Gigahub" charging sites in major cities.

More: *Grist*

Business Network for Offshore Wind Changes Name to Oceantic Network

The Business Network for Offshore Wind recently rebranded itself as the Oceantic Network.

On the company's site, it said its new name "honors the earth's oceans. It celebrates that dynamic natural force that is a source of enormous clean, renewable power and connects all that we do. With this rebrand, we will shift our focus to ensuring we realize the full renewable energy potential of our oceans."

The company says its driving purpose is to inform, coordinate and mobilize human ingenuity, enterprise and labor to take advantage of the urgent need to tap the vast renewable energy resources that lie offshore in the world's oceans.

More: *Oceantic Network*

Federal Briefs

Whistleblower Says Southern Co. Should Repay $382M in Federal Aid

Kelli Williams, a former construction manager for Southern Co., filed a whistleblower lawsuit against the company and its subsidiary Mississippi Power in 2018. The lawsuit, unsealed Oct. 30, alleges the two firms defrauded DOE, as well as state regulators, in a failed quest to build a $7.5 billion power plant in Kemper County.

Williams said the company lied repeatedly about the plant's cost overruns and spiraling delays, enticing DOE to keep delivering subsidy payments and persuading the Mississippi Public Service Commission to not revoke its permission for construction. Williams claims she knows about the wrongdoing because she was repeatedly ordered to prepare unrealistic budget documents that the company provided to regulators to mislead them that the project was on track.

If found guilty, the company could be forced to pay more than $1.1 billion in damages.

More: *WABE*

DOE to Pay $440M to Install Solar Panels in Puerto Rico

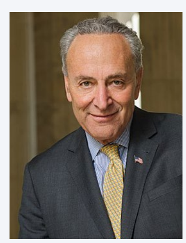
DOE last week announced that it will pay $440 million to install solar panels in Puerto Rico.

The department said the funding will lower energy costs for 30,000 to 40,000 single-family households and help improve the resilience of energy sources.

DOE selected three companies and five nonprofits to install the panels. The department noted that there is an existing workforce in Puerto Rico for the corporations to install the panels.

More: *The Hill*

Senators Demand FTC Probe of Oil Industry Mergers



Senate Majority Leader **Chuck Schumer** (D-N.Y.) and 22 other Democratic senators sent a letter to Federal Trade Commission Chair Lina Khan last week demanding an investigation of two major proposed oil industry mergers.

The mergers in question are ExxonMobil's proposed $60 billion acquisition of Pioneer Natural Resources and Chevron's proposed $53 billion acquisition of Hess Corporation.

The senators called on the FTC to consider various anti-competitive harms and urged the agency to oppose them if they would violate antitrust law.

More: *The Hill*

State Briefs

ARIZONA

Tucson Electric Plans High-Voltage Tx Link to Pima County's Aerospace

Tucson Electric Power recently filed for the approval of a new transmission line extension to deliver high-voltage power to Pima County's Aerospace Research Campus.

The proposed transmission line will link TEP's existing 138-kV transmission system to the proposed Franco Wash Switchyard, according to TEP's application to the Power Plant and Transmission Line Siting Committee.

The committee has set a public hearing on the matter starting Dec. 4.

More: *Arizona Daily Star*

COLORADO

Study: State to Hit 98.5% Carbon Cuts from Electricity by 2040

The state's electric power sector can cut greenhouse gas emissions by 98.5% by 2040 without major policy changes or major new costs to consumers, according to an analysis by the state's Energy Office.

The scenario would cut Colorado's electricity-related carbon emissions to 565,000 tons in 2040, from the 2005 benchmark of 40 million tons. One scenario in the analysis, which tested multiple combinations of policy and technology, put the cost of getting to 100% at about $9 billion in additional power spending.

More: *The Colorado Sun*

INDIANA

Canadian Solar to Open Solar Cell Factory in Jeffersonville

Canadian Solar last week announced plans to invest $800 million to develop a 5-GW solar cell manufacturing site in Jeffersonville.

Once complete, the factory is expected to produce enough cells to supply the production of about 20,000 solar modules per day. The cells produced at the facility will be used at its new Mesquite, Texas, module assembly plant.

The company said it expects to begin production in 2025.

More: *pv magazine*

DeKalb County Commissioners Reject Solar Farm

The Dekalb County Commission last week voted 3-2 to reject a resolution that would have allowed EDF Renewables to move forward with a planned solar farm.

The decision comes after more than two years of debate centered around property rights, taxes and development.

More: *WPTA*

KANSAS

Regulators Deny Release of Natural Gas Invoices from 2021 Winter Storm

The Corporation Commission last week denied an Open Records Act request to release Black Hills Energy's invoices from Winter Storm Uri to the public.

Jim Zakoura, an attorney specializing in energy law who is pursuing two price gouging lawsuits, said the request for prices and volumes purchased will show whether the payments to gas suppliers complied with state law, and if not, help calculate damages.

The commission decided that the public doesn't need the documents to pursue litigation, and determined that making the supplier invoices public "would cause harm to both Black Hills and the public" by potentially affecting "their ability to compete for low-cost gas supplies in the future."

More: *Topeka Capital-Journal*

MINNESOTA

Utilities Look to Rate Increases

CenterPoint Energy and Xcel Energy have both filed for a rate increase of more than 9% with the Public Utilities Commission.

CenterPoint split its request over two years, asking for an increase of $84.6 million (6.5%) in 2024 and another $51.8 million (3.7%) in 2025. The increases would add about $5.91 (2024) and $2.58 (2025) a month to a typical bill. Xcel asked for an increase in 2024 of $59 million (9.6%), which would add $6.93 a month. The utilities said the increases are needed to pay for infrastructure, inflation and supply-chain shortages.

Minnesota Power is also seeking a 12% increase, which if approved would raise the average bill by about $11 a month.

More: *Star Tribune*, *MPR News*

NEW YORK

15 Injured in Apparent Building Explosion

Fifteen people were injured last week when a gas line was struck in the Village of Wappingers Falls, destroying a residential building in an apparent explosion, authorities said.

Wappingers Falls Fire Chief Jason Enson said an excavator ruptured the gas line and that crews arrived at a working fire with people trapped in the rubble.

Eric Kiszkiel of Central Hudson Gas & Electric said crews had been doing routine maintenance in the area and were replacing a gas main. The infrastructure in the area could date to the 1930s or '40s, he said.

More: *NBC News*

NYC Wants to Transform Staten Island Rail Yard into Clean Energy Site

The New York City Economic Development Corporation issued a request for proposal on Oct. 18 for the development of the Arlington Yard's use in clean energy development.

In addition to the Arlington Yard project, which is part of the freight train line that runs from the Howland Hook Terminal, the EDC's request also includes another site in the Bronx to be developed for the same purpose. The city-controlled non-profit has an interest in developing the sites for offshore wind, large-scale renewables or transmission uses.

Proposals are due by Dec. 18.

More: *Staten Island Advance*

NORTH DAKOTA

Summit Outlines Pipeline Reroutes to PSC

Summit Carbon Solutions last week notified the Public Service Commission of reroutes to its carbon capture pipeline as it tries to obtain a route permit.

Summit outlined measures it has taken since the PSC rejected its application for a route permit, which it has since appealed. The company's original South Dakota application was also rejected.

More: *AG Week*

PENNSYLVANIA

Attorney General Sues Equitrans in Relation to House Explosion

Attorney General Michelle Henry last week announced criminal charges against Equitrans Midstream, accusing the company of failing to fix a natural gas leak that led to a house explosion in 2018.

A couple and their 4-year-old son suffered severe burns after their home exploded five years ago. They were unaware that their home sat atop a natural gas storage field. A nearby gas storage well was deteriorating, allowing methane to accumulate in the house's water supply, according to the attorney general's office. An investigation found that Equitrans admitted in federal filings prior to the blast that the field was losing gas and the wells were leaking.

Equitrans is facing one felony charge and two misdemeanor charges under the state's Clean Streams Law for failing to properly maintain the well and for not investigating the explosion.

More: *Trib Live*

Court Strikes Down RGGI Participation

Two court decisions last week struck down the state's participation in the Regional Greenhouse Gas Initiative, as the rulings found that former Democratic Gov. Tom Wolf's attempt to join RGGI was an overstep in executive power.

At the heart of the cases is whether the RGGI regulation on energy producers constitutes a tax or a licensing fee. Critics argue it's a tax and that only the legislature has the power to levy taxes. Because Wolf joined RGGI through an executive order without input from the legislature, opponents say this makes the program unconstitutional. Meanwhile, supporters claim the state can regulate companies under the federal Clean Air Act and imposing an emission limit does not constitute a tax, but a fee, which the governor doesn't need legislative authority to impose.

The cases can be appealed to the state Supreme Court within 30 days.

More: *Spotlight PA*

DEP Partners with Natural Gas Driller on Air, Water Monitoring

CNX Resources will partner with the Department of Environmental Protection on intensive environmental monitoring at two future natural gas well sites throughout all stages of the drilling and fracking process in a data-collection exercise that could be used to drive future policy changes, Gov. Josh Shapiro (D) said.

Under the agreement, CNX will report air quality data beginning with one of its existing wells in Washington County and eventually expand to its entire state operation. The company also agreed to disclose the chemicals it plans to use at a well site before the start of drilling and fracking.

The announcement comes amid ongoing concerns about the potential environmental and health effects of fracking, and more than three years after a grand jury concluded that regulators had failed to properly oversee the state's gas-drilling industry.

More: *The Associated Press*