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# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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**COVER:** Diablo Canyon Power Plant sits on the coast of Central California.| *PG&E*

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## CAISO/West News

# Calif. Legislature Passes Climate, Energy Bills

By Hudson Sangree

Diablo Canyon Power Plant sits on the coast of Central California. | *PG&E*

California lawmakers passed a last-minute package of climate and energy bills on Wednesday night that Gov. Gavin Newsom wanted to bolster grid reliability and reduce greenhouse gas emissions.

The last day of the 2021/22 legislative session saw lawmakers vote to reverse the state's decision to close its last nuclear plant, Pacific Gas and Electric's Diablo Canyon facility, by 2025. The Senate and Assembly approved Senate Bill 846, which *grants* PG&E a $1.4 billion forgivable loan to keep Diablo Canyon operating five years beyond its scheduled retirement.

The plant supplies nearly 9% of the state's electricity needs and 17% of its carbon-free energy, the measure says.

"Preserving the option of continued operations of the Diablo Canyon powerplant for an additional five years beyond 2025 may be necessary to improve statewide energy system reliability and to reduce the emissions of greenhouse gases while additional renewable energy and zero-carbon resources come online," it says.

Newsom, who backed the bill, signed it Friday. Continued operation of Diablo Canyon will require approval of the U.S. Nuclear Regulatory Commission.

Grassroots advocacy group Californians for Green Nuclear Power (CGNP) has pushed for the move since before many politicians were convinced that keeping the plant open made sense. Newsom and other officials gradually came around to CGNP's point of view as the state struggled to maintain grid reliability starting with the rolling blackouts of August 2020.

"This has been the culmination of a decade of work for CGNP, of thousands of hours of research, filings, outreach and testimony," the group's president, Carl Wurtz, said in a prepared statement. "It's unfortunate it took the lights going out for many to appreciate Diablo Canyon's value, but better late than never."

Others continue to believe nuclear power is wrong for California. A contingent of lawmakers said the $1.4 billion could be better spent on fast-tracking more solar, wind and storage resources to meet the state's goal of relying on 100% clean energy by 2045.

Negative reaction to SB 846's passage included a statement by the nonprofit Environmental Working Group saying, "This action can only hurt the state's shift to safe, renewable energy and prolong the risk of a disaster at the plant." The "bailout bill" was rushed through the Legislature at Newsom's bidding in the last week of the session, with little time for review by lawmakers and the public, it said.

"The bill … which goes into effect immediately, extends the plant's carefully planned and negotiated [retirement]," EWG said.

A 2016 agreement among PG&E and environmental and labor groups initially laid out plans for Diablo Canyon's closure. The California Public Utilities Commission in January 2018 approved the 2,200-MW plant's retirement. The bill invalidates that decision while ordering the CPUC to reopen its Diablo Canyon proceeding.

SB 846 also instructs the CPUC to submit to the Legislature a cost-benefit analysis of keeping the plant open from 2024 to 2035 compared with adopting a portfolio of "other feasible resources" consistent with the state's greenhouse gas reduction goals, and a "reliability planning assessment" with supply-and-demand forecasts for five- and 10-year periods under several risk scenarios.

### Climate Bills

Other measures passed by lawmakers last week at Newsom's behest included:

- Assembly Bill 1279, the "California Climate Crisis Act," which would *codify* former Gov. Jerry Brown's 2018 executive order requiring the state to become carbon neutral by 2045 and to "achieve and maintain net-negative greenhouse gas emissions thereafter."
- SB 1020, which would *establish* new interim targets for the state's effort, under 2018's Senate Bill 100, to supply all retail customers with 100% zero-carbon energy by 2045. The bill would make it state policy to supply 90% clean energy to retail customers by the end of 2035, upping that amount to 95% by Dec. 31, 2040.
- SB 905, which would *require* the California Air Resources Board to establish a program to capture and store carbon dioxide, and AB 1757, which would *task* the state's Natural Resources Agency with establishing ambitious carbon sequestration targets for "natural and working lands" by Jan. 1, 2024.

One Newsom-backed bill failed Wednesday. AB 2133 would have *accelerated* the state's GHG reduction goals from 40% below 1990 levels to 55% below those levels by 2030. The bill failed in the Assembly after members of the lower house could not agree to support some Senate amendments. ■

## CAISO/West News

# Transmission Bills Achieve Mixed Results in California

### *Efforts Fizzle to Make Transmission Development Faster and Cheaper*

*By Hudson Sangree*

The California legislature's recently completed session saw a handful of bills introduced to promote transmission development, but only one of the measures escaped unscathed while the rest died or were watered down.

The bills mainly aimed to move more energy from renewable resources to help the state meet its goal of relying on 100% clean energy by 2045, as required by 2018's Senate Bill 100.

The only significant bill to emerge intact was *SB 887* by Sen. Josh Becker (D).

The bill would direct CAISO, the California Public Utilities Commission and the state Energy Commission to expand their generation and transmission planning horizons from the current 10 years to "at least 15 years … to ensure adequate lead time for [CAISO] to analyze and approve transmission development and for the permitting and construction of the approved facilities."

CAISO already performs a 20-year transmission outlook, but it is a long-term conceptual plan of grid needs, including out-of-state projects, intended to complement but not replace the ISO's 10-year transmission planning process, which concerns only in-state projects.

Becker's bill would instruct CAISO to identify "the highest priority transmission facilities that are needed to allow for reduced reliance on [fossil fuel] resources in transmission-constrained urban areas by delivering renewable energy resources or zero-carbon resources that are expected to be developed by 2035 into those areas."

It cleared the Assembly on Aug. 29 and goes to Gov. Gavin Newsom for his signature or veto by Sept. 30.

One bill, which had been considered a major transmission measure in the 2021/22 legislative session, was stripped of its more substantive provisions and became a new law requiring utilities to file annual reports with the CPUC.

*SB 1174*, by Sen. Robert Hertzberg (D), a former Assembly speaker, would have directed the CPUC to work with CAISO, the Energy Commission and the state Air Resources Board to "identify all interconnection or transmission projects necessary to achieve" the goals of SB 100 and to prioritize approval of the projects.

One of those needs could be a 200-mile undersea cable linking offshore wind farms in far northern California to San Francisco and other population centers. Such large-scale projects mean that speeding transmission "may be one of the most important steps we can take to connect bold planning with common-sense policy," Hertzberg said in a statement earlier this year.

The measure that cleared the legislature on Aug. 30, which Newsom signed Friday, was limited to requiring each regulated utility that owns transmission to annually prepare a report for the CPUC "on any changes to previously reported in-service dates of transmission and interconnection facilities necessary to provide transmission deliverability to eligible renewable energy resources or energy storage resources that have executed interconnection agreements."

Two bills that failed were:

- *SB 1032*, also by Becker, that sought "faster and cheaper transmission development" by directing the CPUC to identify "proposals to accelerate the development of, and reduce the cost to ratepayers of expanding, the state's electrical transmission grid as necessary to achieve the state's goals [of reducing greenhouse gas emissions.]" Measures to be studied would have included public ownership of transmission facilities, public financing of transmission projects and the use of non-ratepayer funds to cover part of the cost of transmission projects needed to achieve the state's clean energy goals. It died in the Assembly Appropriations Committee in mid-August.
- *AB 2696* by Assemblymember Eduardo Garcia (D-Coachella), chair of the Assembly Utilities and Energy Committee, was intended to lower the costs of transmission development. It would have told the CPUC, in consultation with CAISO and other entities, to study "potential lower cost ownership and alternative financing mechanisms for new transmission facilities needed to meet the state's clean energy and climate targets" including public ownership, public financing and partnerships with federal agencies. It died in the Senate Appropriations Committee on Aug. 11. ■

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## CAISO/West News

# CAISO Extends RMR Contracts for Gas Plants

### *Plants as Small as 27.5 MW Needed for Summer Reliability, CAISO Says*

*By Hudson Sangree*

The CAISO Board of Governors on Wednesday extended reliability must-run (RMR) contracts for a group of small, aging natural gas plants that the ISO says are needed for summer grid reliability.

The generating units have capacities of 27.5 to 248 MW, with most on the low end of that range.

"The Board's action is part of its focus, along with state energy agencies, to make sure all available generating capacity can be used during the summer months, when stressed conditions on the grid are most common," CAISO said in a news release.

RMR contracts require power plants to continue operating to meet systemwide and local capacity needs for the term of the agreements in return for additional compensation.

The governors made their decision during an unusually short monthly meeting held on the same afternoon as a severe heat wave descended on the West and the ISO issued its first energy emergency alert of the summer.

The ISO's original approval of the RMR contracts, starting in 2019, was part of its push to keep all available resources running after the ISO projected possible summer shortfalls from 2020 through at least 2024. Energy emergencies in August and September 2020 and again in July 2021 appeared to confirm those projections.

Generators can be released from RMR contracts if they sign resource adequacy capacity contracts, another way of ensuring they keep operating.

"Total capacity and the number of resources under reliability must-run contracts with the ISO has been significantly reduced since the implementation of the state's resource adequacy program and the addition of new grid facilities," Neil Millar, CAISO vice president of infrastructure and operations planning, said in his *memo* to the board. "However, reliability must-run contracts remain an important backstop instrument to ensure reliability when other alternatives are not viable."

The plants for which contracts were extended through 2023 are the California State University-Channel Islands Site Authority's Channel Islands Power plant (27.5 MW), Starwood Energy Group's Greenleaf II Cogen plant near Yuba City (49.2 MW), Dynegy Oakland's Units 1 and 3 (55 MW each), and two Midway Sunset Cogen units in a Kern County oil field (totaling 248 MW).

The Midway Sunset Cogeneration plant sits in a Kern County oil field. | *Antandrus, CC BY-SA 3.0, via Wikimedia*

Another unit, the KES Kingsburg, LP Kingsburg Cogen plant (34.5 MW) will be released from its RMR contract at the end this year after signing a multi year resource adequacy capacity contract.

"The Dynegy Oakland resources are required to meet the 2023 local capacity requirement in the Oakland sub-area of the Bay Area local area," pending the completion of transmission projects and a 55-MW battery system, Millar wrote.

"Greenleaf II Cogen continues to be required to meet the 2023 local capacity requirement in the Drum-Rio Oso sub-area of the Sierra local area," he said. "The sub-area local capacity requirement was determined to be 750 MW, and there are only 558 MW (553 MW at peak) of total available resources in the sub-area including the Greenleaf II Cogen unit." A 230/115-kV transformer project is expected to mitigate the reliability need by March 2024, he said.

CAISO needs the Channel Islands and Midway Sunset units to meet 2023 and 2024 systemwide reliability requirements.

"The critical concern at this time is the dependence on a significant volume of new construction required in 2026 — over 6000 MW of additional net qualifying capacity — to meet the mid-term reliability authorization amounts set out [in a decision] by the [California Public Utilities Commission]," the memo says.

"Further, this development is coming on the heels of two years of already aggressive development to meet 2022 and 2023 requirements. If half of the 2024 procurement is delayed, the ISO would fall below the [necessary] 18.5% planning reserve margin requirement. … Management considers this to pose a risk to reliability at this time."

CAISO also is talking with the governor's office about making the units part of the state's new multi billion dollar strategic reliability reserve in hopes of avoiding the RMR extension, Millar said. ■

## CAISO/West News

# FERC OKs CAISO Interconnection Updates

*By Hudson Sangree*

FERC last week approved a dozen CAISO tariff amendments meant to streamline the ISO's generator interconnection process, deal more swiftly with its large interconnection queue and help California meet its grid reliability challenges. (*ER22-2018*).

The changes were the result of the *first* phase of a two-part stakeholder initiative that CAISO fast-tracked starting last year. The second *phase* is underway with a final proposal due Sept. 13.

FERC found that the Phase 1 revisions will "facilitate management of CAISO's interconnection queue, clarify the tariff, and establish a just and reasonable process for CAISO to study emergency interconnection requests on an expedited basis."

Changes approved by FERC came from a CAISO stakeholder process on interconnection enhancements. | *Shutterstock*

The 12 amendments included a proposal to align the ISO's transmission plan deliverability allocation process with procurement by consolidating the current seven interconnection customer deliverability allocation groups into four, making it easier for CAISO to track the process and providing clearer criteria for developers and off-takers.

"Additionally, the new groups are reordered to emphasize success in the bilateral capacity markets and de-emphasize a project's queue status and history," FERC said in its unanimous Aug. 31 order.

The amendments also would allow interconnection customers to downsize their interconnection requests.

"CAISO's proposed revisions to the transmission plan deliverability allocation process and to the downsizing rules simplify CAISO's administration of the interconnection queue and the process through which interconnection customers may request to downsize their interconnection requests, as well as help to reduce unused deliverability," FERC said.

Another change affects CAISO's requirement that customers show they have "site exclusivity" through options, leases, or purchases on private land or permits for public lands. Customers can submit deposits in lieu of initially demonstrating site exclusivity.

CAISO proposed requiring projects show that they have site exclusivity earlier and increasing the "in lieu deposits" from $100,000 for small generators of 20 MW or less and $250,000 for large generators of more than 20 MW to $250,000 for small generators and $500,000 for large generators, with half the deposits nonrefundable "should the customer withdraw before demonstrating site exclusivity."

FERC said the site-exclusivity provisions will "improve the likelihood that commercially feasible interconnection requests can move forward in the queue without encountering delays due to the withdrawal of interconnection requests that have not demonstrated site exclusivity and are thus less likely to reach commercial operation."

The 10 other categories of tariff amendments dealt with matters such as enabling interconnection studies of new generation under last year's emergency declaration on grid reliability by Gov. Gavin Newsom and reducing CAISO's downsizing rules and procedures to help interconnection customers downsize more efficiently.

FERC allowed the changes to take effect Sept. 1, per CAISO's request. ■

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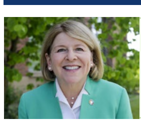

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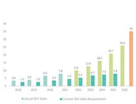

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## CAISO/West News

# CAISO Stakeholders Weigh EDAM Proposal

*Meetings on Revised Straw Proposal to Continue this Week*

*By Hudson Sangree*

CAISO kicked off a series of stakeholder meetings last week on its revised straw proposal to add a day-ahead market to the real-time Western Energy Imbalance Market (WEIM), a major expansion push for the ISO in the West.

Potential participants in the *extended day-ahead market* (EDAM) were able to ask questions of CAISO planners and offer their thoughts on the plan's specifics, including a proposed resource sufficiency test and resource participation, during the Aug. 29 *meeting*.

Carrie Bentley, an energy consultant representing the Western Power Trading Forum, asked why CAISO's proposal would require that all resources in a participating balancing authority area (BAA) take part in EDAM when that's currently not the case in the WEIM.

"I was hoping you could provide more color on why the CAISO was removing the option for resources to be nonparticipating?" Bentley said. "It was my understanding that in WEIM, the amount of nonparticipating resources [as a percentage of capacity] is pretty high. So perhaps if you could tell me … why you're removing that option? And then whether you're going to then remove it from WEIM as well? It just seems to remove a lot of optionality."

CAISO Executive Principal George Angelidis said the "reason why we eliminated the option for the nonparticipating resource concept that we're using in the Western Energy Imbalance Market is that we don't see the value for it, in the sense that it doesn't give you anything different than a normal resource that participates in the market with a self-schedule and not submitting bids. The submission of bids is voluntary in EDAM, with the exception, of course, of resource adequacy, [so] we just didn't see any difference between participating and nonparticipating resources."

Bentley said she understood but still saw possible benefits to having the option of nonparticipating resources.

### Resource Sufficiency

On the topic of resource sufficiency, Powerex Director of Power Jeff Spires said CAISO's proposal to use "e-tags" to track the fulfillment of firm energy contracts in EDAM was essential but that a second proposal to allow participants to backfill capacity at the last minute undermined the process.

The EDAM revised straw proposal introduced the "tagging mechanism," or e-tag, a means of electronically monitoring and recording energy transactions for firm energy contracts. The proposal requires "all non-source-specific forward supply contracts [to] be tagged within three hours following publication of the day-ahead market results."

"This will increase confidence that this non-source-specific forward supply will be delivered in real time because submitting a tag requires resource and transmission identification." (See *CAISO Updates EDAM Straw Proposal*.)

Spires said, "We all know by this point … that resource sufficiency is one of the fundamental elements of the EDAM and that really is one of the first steps that we need to get right before the remaining market design elements can fit together and work. You know, it all kind of starts with an assumption that there's enough supply across the footprint and that everyone's bringing their fair share."

"That requires ensuring that the [resource sufficiency] test is representative of both the supply and the obligations of each BA and in the context of imports," he said. "In our view, that means that imports that are being used to meet the resource efficiency evaluation need to be real; they need to be deliverable to the BA that's counting on them. And a day-ahead e-tag is a critical element to be able to demonstrate that the import is supported by a resource and that there's transmission to deliver it."

CAISO, however, is also proposing that "non-tagged schedules will be required to submit e-tags, or otherwise cure shortfall, by the start of the STUC [short-term unit commitment] horizon for the hour in which the failure occurred," a slide in the ISO's presentation said.

The revised straw proposal says that when an EDAM participant is short on supply in the day-ahead time frame, "it can backfill the deficiency with supply" in the short-term horizon "ending in the hour" of the shortage.

That part is a challenge, Spires said, "because it essentially renders that day-ahead e-tag requirements as optional. And what it really leads to is enabling an entity to point to an import that isn't supported by identifiable supply or transmission and essentially says that 'that's OK,' as long as that participant is able to successfully find supply or transmission or both in real time. And that's very problematic in our view. It erodes confidence in the test itself because it effectively says that an entity can pass [the EDAM's resource sufficiency test] even though they are going into real time short of resources and or transmission."

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

In reply, CAISO Market Design Sector Manager Danny Johnson said, "I think we do understand your position and Powerex's position on this. I think what we're trying to explore here is, 'Is there a model that deviates from [the day-ahead e-tag] that also provides confidence to all of the interested BAA partners in this?' And that's what we're exploring in this proposal. And I do think there are some teeth to this. We will be reporting out if this doesn't occur regularly. If an EDAM BAA does eventually fail to tag by [the start of the hour in the STUC horizon for which the failure occurred], they would get kicked out of [a pooled resource sufficiency evaluation], and I think we even have provisions that the export transfers into that EDAM BAA would get a lower priority if it came to manual curtailments if the market was unable to solve. So, I do think this has some teeth" and provides confidence level in the EDAM's resource sufficiency evaluation.

The EDAM stakeholder meetings *resume* this week with sessions on Wednesday and Thursday, including an in-person option in downtown Sacramento. ■

# CAISO Warns of Outages amid Record Heat

*By Hudson Sangree*

CAISO CEO Elliot Mainzer said the state's grid is facing its biggest challenge yet this summer as record temperatures bake large areas of California in a prolonged heat wave this week.

"This multiday event is going to get much more intense," Mainzer said in a call with reporters Sunday. "We're facing energy deficits between 2,000 to 4000 MW for tomorrow, and the highest likelihood of rotating outages that we've seen so far.

"As a result, we are going to need significant additional consumer demand reduction during the hours of 4 to 10 p.m. and access to all of the tools that the state and the utilities have established for conditions like this in order to avoid broader interruptions of service. So, it is game on and time for continued focus."

CAISO issued a second-stage energy emergency alert Monday evening but was able to avoid ordering rolling blackouts. The danger from extreme temperatures continues, however.

The National Weather Service predicted high temperatures Tuesday in the state's Central Valley of up to 115 degrees Fahrenheit, a level of extreme heat more often associated with areas such as Death Valley. The forecast for Sacramento called for a high temperature of 113 F for today.

In Southern California, home to 24 million residents, Downtown Los Angeles would see temperatures of over 100 degrees this week, the weather service said.

Even San Francisco, normally cool in the summer, was expected to top out at 87 F today. The weather service said parts of the heavily populated San Francisco Bay Area would be much hotter, with some cities reaching a record 105 degrees or more.

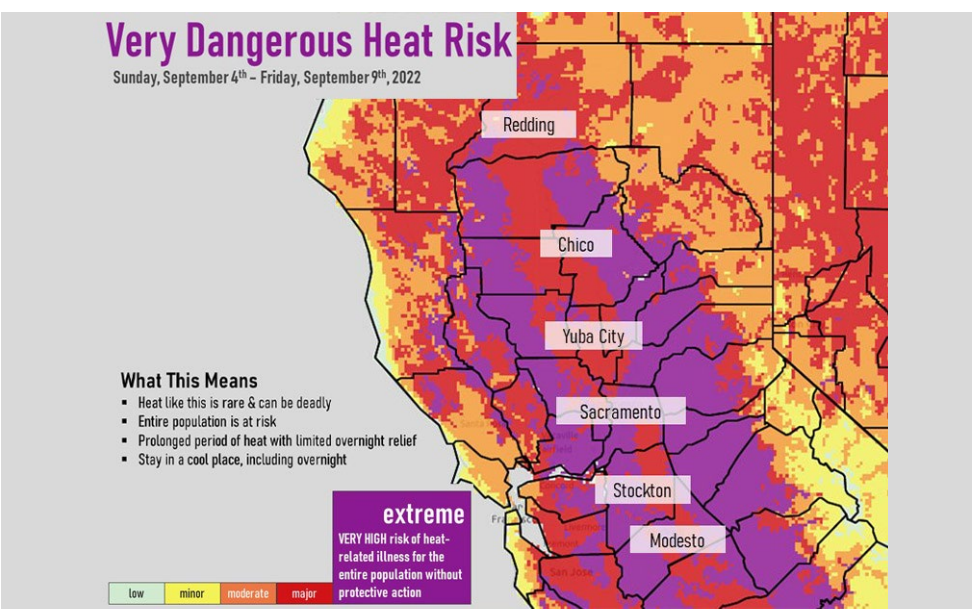
CAISO is predicting demand of 51,145 MW for today. That would beat the record of 50,270 MW from July 2006.

Though several large fires were burning in Northern and Southern California, none had impacted the transmission system.

Mainzer said the ISO was monitoring for new wildfires with the potential to derate high-voltage lines and limit imported hydroelectricity from the Pacific Northwest, an essential supply source for California during summer months.

A massive wildfire in southern Oregon severely derated the Pacific AC and DC interties during a Western heat wave last July, shutting off power from hydroelectric dams in Washington and Oregon to California.

CAISO did have to declare a transmission emergency Monday for one line that was overloaded in the heat. Real-time electricity prices on Monday evening exceeded $1,500/kWh in many areas, sometimes topping $1,800.




The National Weather Service predicts a record of high of 115 degrees Fahrenheit in the Sacramento Valley today. | *National Weather Service*

## Extreme Weather

This week's extended period of record heat is the latest in a series of extreme weather events that have troubled California and other areas of the West in recent years. A heat dome over the usually mild, rainy Pacific Northwest in June 2021 pushed temperatures to 115 F in Portland, Ore., and 107 F in Seattle, with some inland areas hitting 118 F.

West-wide heat waves and supply constraints struck the Western grid in August and September 2020, causing CAISO to order rolling blackouts in mid-August of that year and to declare energy emergencies over Labor Day weekend. The August blackouts affected more than 2 million residents for periods ranging from roughly 30 minutes to three hours.

Since then, CAISO has interconnected several thousand megawatts of lithium-ion batteries to its grid, almost all with four-hour discharge capabilities. The batteries are intended to make up for shortfalls during hot summer evenings and have performed according to expectations so far. How the batteries will perform in more extreme conditions is being tested this week.

Until now, California's summer has been relatively mild this year with the exception of a less severe heat wave in mid-August, when CAISO issued a "flex alert" asking customers to reduce usage.

In anticipation of hotter weather this week, California Gov. Gavin Newsom on Wednesday proclaimed a state of emergency aimed at temporarily increasing energy production and reducing demand in response to an extreme heat wave forecast to hit the state this weekend. (See *Newsom Declares Emergency as Heat Stresses Calif. Grid*.)

Newsom's emergency proclamation will allow gas-fired power plants to generate additional electricity by loosening air quality requirements and restrictions on fuel use. The proclamation relaxes restrictions on the use of backup generators from 2 to 10 p.m. on days in which CAISO has declared a level 2 or 3 EEA. Ships berthed at California ports also won't be required to use shore power during such times.

"We are anticipating this extreme heat to be of a length and duration the likes of which we haven't experienced in some time," Newsom said in announcing the declaration. ■

*Elaine Goodman contributed to this story.*

ERCOT News

# ERCOT, Brazos Reach Agreement in Bankruptcy Case

## *Cooperative to Pay Grid Operator $1.44B to Settle Winter Storm Charges*

*By Tom Kleckner*

Brazos Electric Power Cooperative has offered to pay ERCOT as much as $1.44 billion in its proposed exit plan from Chapter 11 bankruptcy and settle its dispute with the Texas grid operator over astronomical wholesale power prices in the wake of the February 2021 winter storm.

Brazos' Jack County power plant is up for sale. | *Fluor*

Under the terms of a *settlement agreement* and *reorganization plan* filed Thursday with the U.S. Bankruptcy Court for the Southern District of Texas, Brazos will make an initial payment of $1.15 billion. It will then make annual payments to ERCOT of $13.8 million for 12 years and contribute a portion of the sale of its generation assets, about $116.6 million, to fund payments through the grid operator to market participants still short from market transactions during the week of the storm (*21-30725*).

The initial lump sum will be used to help replenish a fund ERCOT used to settle transactions following the storm and to finance an initial distribution to market participants that joined in the settlement.

ERCOT had no comment on the filings, keeping with its practice of not remarking on legal matters. However, it told stakeholders in a *market notice* that it has not yet reached a final agreement on "certain important provisions in the plan." It also noted that both the plan and a disclosure statement are working drafts and will be amended to reflect ongoing discussions and negotiations with Brazos and other key stakeholders.

The bankruptcy court has scheduled a hearing for Sept. 14 to determine whether the plan meets U.S. Bankruptcy Code requirements. Assuming confirmation, Brazos will then begin soliciting votes, due Oct. 27, from ERCOT and market participants on the agreement. Another hearing has been scheduled for November to consider final approval of the settlement and reorganization plan.

Brazos filed for bankruptcy in March 2021 after receiving an invoice from ERCOT for $2.1 billion in market transactions that it was short the market, with payment due in a few days. The cooperative responded with a *force majeure* event letter and by disputing the charges. (See *ERCOT's Brazos Electric Declares Bankruptcy*.)

The co-op then opened an adversary proceeding against ERCOT in August 2021, challenging the Public Utility Commission's emergency orders directing the grid operator to set prices at their $9,000/MWh limit to reflect the scarcity in the market. It sought to reduce the short-pay claim by at least $1.1 billion, the amount it attributed to ERCOT's administrative adjustment.

Wholesale prices remained at their maximum for four straight days after the grid came within minutes of total collapse. ERCOT also increased ancillary fees to more than $25,000/MWh as it desperately sought to balance demand with load after a devastating loss of generation that led to long-term blackouts.

"The consequences of these prices were devastating to Brazos Electric and its members," the cooperative said in its restructuring plan.

The adversary proceeding trial began earlier this year but was suspended after several weeks to allow the parties to mediate the dispute. (See *ERCOT, Brazos Agree to Mediation in Dispute*.)

ERCOT has said that almost all of the Brazos short-pay claim should be entitled to priority treatment as an administrative expense claim in the bankruptcy case. The short-pay amount has been revised to $1,886.6 billion, which will be fully recovered.

When Brazos comes out of bankruptcy, it has agreed to sell its generating assets, which total about 4 GW of capacity, and transition from a generation and transmission cooperative to a transmission and distribution cooperative. All of Brazos' generation is natural gas-fired.

Under the agreement, Cliff Karnei, Brazos' general manager since 1997, and three other members of the cooperative's senior management will leave their jobs by March 2023. In addition, Karnei and two others will be barred from working for any ERCOT market participant if they're acting as a financial counterparty to the grid operator.

Karnei resigned from ERCOT's Board of Directors last year shortly after the storm hit, ending two decades of service on the board. ■

# ERCOT News

# Texas Advisory Committee: Renewables Create 'Operational Challenges'

## *Report to State Legislature Focuses on Need for Dispatchable Generation*

*By Tom Kleckner*

Ice hangs on power lines during the 2021 winter storm. | *Entergy*

A committee formed by Texas' political leadership has produced what it calls a "comprehensive" state energy plan to guide lawmakers and stakeholders in making further changes to ERCOT's wholesale market.

The State Energy Plan Advisory Committee's (SEPAC) *report* identifies how Texas "can best adapt to the changing electric generation resource mix and support market-based incentives" that ensure the generation supply is "adequate, resilient and poised to support the continued economic growth in this state" as a key problem.

The report says witnesses who provided testimony during one of the committee's two meetings acknowledge intermittent renewable resources have provided additional capacity and low-cost energy, but that they have also introduced new "operational challenges."

"The key reliability issue facing ERCOT will be to ensure adequate dispatchable generation is available during times of low non-dispatchable output," the report says, calling for a clear reliability metric or standard. "The committee believes this is a necessary first step in evaluating the efficacy of the proposals under consideration. … The more that power systems rely on wind, solar and battery storage systems, the greater the risk that a major grid disturbance will cause the grid to cascade into a blackout condition."

SEPAC recommends that renewable resources be required to "firm their deliveries" with dispatchable generation. That would burden renewables with additional costs in a market designed to pay generators for the energy they produce.

"The committee does not support a market design that favors new or subsidized generation over existing resources, as doing so could create regulatory inefficiencies and raise capital costs for Texas ratepayers," it said.

According to the report, the committee found "broad support for favoring competitive solutions to manage the uncertainty that ERCOT presently is addressing through out-of-market reliability actions." The grid operator's conservative operations posture, where it keeps several thousands of megawatts of resources in reserve, has led to billions in additional operating costs and wear and tear on generators.

Joel Mickey, one of SEPAC's 12 members and a former ERCOT staffer, concurred with the overall report — approved by a 7-5 vote — in an appended statement because of the report's statutory deadline to be submitted to the Legislature. However, he dissented on two additions that he said were added at the last minute. (See "Energy Advisory Committee OKs Report," *ERCOT Could Name New CEO this Week*.)

"These additions, in my opinion, have not been adequately vetted and could cause significant reliability problems within the [ERCOT] grid," Mickey said, referring to the recommendation requiring renewable resources to pay for dispatchable energy and SEPAC's lack of support for a market design that favors other resources over existing generation.

"I strongly support the competitive market structure in ERCOT and the competition among generators and retail electric providers that provide the best solutions [for Texas]. I believe these additional recommendations undermine the benefits of competition that ensure reliable, clean, affordable electric service," he wrote.

Mickey, who now consults in the energy sector, said the recommendation that renewables firm their energy delivery with a competitor's generation output is "discriminatory and ignores the fundamental purpose of ERCOT as an [ISO]: … the ability to take the energy offered from many diverse resources and to deploy those resources."

"My second concern is the discriminatory application of this recommendation which can be expected to result in thousands of megawatts of existing renewable generation resources shutting down if forced to purchase large amounts of power from their competitors," he said. "This recommendation will discourage new renewable generation from being added to the ERCOT grid. Both results will reduce reliability in ERCOT and increase the likelihood of emergency conditions or rotating outages."

Noting ERCOT resources are paid the same market price for energy produced, Mickey argued that if SEPAC's policy is to discourage favoring any subsidized generation resources, "then it would be important that the state of Texas account for and eliminate the benefits of all direct and indirect state and federal tax breaks, tax incentives and any other subsidies for all existing nuclear, coal, gas and hydro generation resources to ensure that all generation resources are held to the same standard."

R Street Institute senior fellow Beth Garza, who testified before the committee during its first meeting, agreed with Mickey's comments. ERCOT's former market monitor, Garza said forcing renewables to "firm their deliveries" with dispatchable generation would "ham-

# ERCOT News

string" the ISO's ability to operate the market efficiently and reliably.

"One exception is their recommendation that 'the [Public Utility Commission] should define a clear reliability metric or standard for the ERCOT region,'" Garza told *RTO Insider*. "I believe this to be an essential precedent to making any significant market design change."

Other committee members also added concurring and dissenting opinions. Several noted they had not yet seen the final product, and one supplied revisions that she hoped would be included in the report.

Mark Ammerman, a retired Houston banker, called the committee's work "inadequate," saying it was tasked with producing a plan, not a report. He said he did not consent to the final product because the committee had not addressed the key mandates of the legislation that created the committee.

"The requirement of the Senate bill to perform the above analysis and recommendations by Sept. 1, 2022, became impossible when this committee only met for the first time in July," Ammerman said.

The committee was created by *legislation* passed last year and charged with preparing a state energy plan that evaluates ERCOT market's structure and pricing mechanisms, as well as barriers preventing "sound economic decisions." The plan was also to look at ways to improve the grid's reliability, stability and affordability.

The report also notes actions the PUC and the Texas Railroad Commission (RRC), which regulates the intrastate gas industry, have taken to improve coordination between the two sectors and protect them before the next winter storm.

Alison Silverstein | *Texas Tribune*

"To [paraphrase] Gertrude Stein, 'There's not much there there,'" Alison Silverstein, an energy consultant after a regulatory career with the PUC and FERC, said in an email. "Despite the statutory charges to [SEPAC], this report isn't an evaluation of market structure, pricing mechanisms or methods to improve those, nor is it a 'state energy plan' for how to improve state electricity and gas markets. Rather, this is merely a recitation of steps the PUC and RRC are already doing and some cheerleading to keep doing that stuff.

"Because SEPAC performed no analysis or critical scrutiny, its report falls hook, line and sinker for the proposition that ERCOT needs more dispatchable resources, and for the extraordinarily bad and expensive idea that intermittent generators should firm their deliveries using dispatchable generation technologies," she said.

"Most of their recommendations seem to take the form of, 'Keep doing what you're doing,'" concluded Garza, who previously called the committee's work a "check-the-box exercise."

It does acknowledge the thermal outages that occurred during the 2021 storm and the FERC/NERC report that highlighted natural gas's role in fuel supply issues. (See *FERC, NERC Release Final Texas Storm Report*.)

Gov. Greg Abbott, Lt. Gov. Dan Patrick and House Speaker Dade Phelan each appointed four of SEPAC's members. It was chaired by Lower Colorado River Authority General Manager Phil Wilson, whose staff wrote much of the report. ■

# ISO-NE News

## Maine Court Ruling Gives New Life to Contentious Transmission Line

*By Sam Mintz*

Maine's highest court on Aug. 30 ruled that a referendum blocking the New England Clean Energy Connect (NECEC) transmission line may have been unconstitutional, reigniting hopes that the fiercely opposed project could get built after all.

In a 39-page ruling, the Maine Supreme Judicial Court found that part of the ballot question could be invalid because it retroactively applies new laws to the certificate of public convenience and necessity obtained by the project's developer Avangrid and its subsidiary Central Maine Power.

It sent the case back to the Maine Business and Consumer Court for "further proceedings consistent with this opinion."

The ruling is the latest twist in a consequential saga that some clean energy advocates say will shape the future of New England and determine how quickly the region can wean itself off fossil fuels. The line, which would bring energy from hydropower plants in Quebec into New England and is central to Massachusetts' clean energy plans, has been at the center of legal and political battles for years.

It received a signoff from the federal government in early 2021, only to be shot down by Maine voters in a referendum later that year in which 59% voted to ban the construction of "high-impact" transmission lines in the area and require approval from the legislature for future such projects.

The constitutionality of that ballot initiative has been the last-gasp hope of the project's developers, and Maine's highest court came to their aid last week.

"Our analysis and conclusions are not based on the wisdom of either the project or the [ballot] initiative," the five-judge panel wrote. But the initiative would "infringe on NECEC's constitutionally protected vested rights" if the project can show that it engaged in "substantial construction" on the authority granted by the certificate it was granted before the initiative was approved by Maine voters.

ClearView Energy Partners called the ruling a "significant win" for NECEC, but it noted that there are other risks pending.

"We view today's opinion as constructive to CMP's plans to complete the project, but the project developer has not yet overcome all its legal challenges," ClearView's analysts said.

Those include a separate case about a lease from the Bureau of Parks and Lands, a suspended permit from the Maine Department of Environmental Quality, and judicial challenges to two federal permits by environmental groups.

But those remaining challenges didn't stop Avangrid from breathing a sigh of relief.

"This unanimous decision by the law court is a victory for clean energy expansion, transmission development and decarbonization efforts in Maine, New England and across the country," Avangrid said in a statement.

The company said the project has faced opposition from fossil fuel-fired generators at every step.

"It is time to move away from the status quo fossil fuel companies who will undoubtedly continue their fight to maintain a stranglehold on the New England energy market," Avangrid said. "These companies have fought this clean energy project in every legal manner possible, filing challenge after challenge in a desperate effort to hold onto their share of the market. Maine's highest court has rejected their latest challenge as unconstitutional."

A portion of the right of way for the New England Clean Energy Connect transmission line. | *Roger Merchant*

The ruling was also celebrated by the transmission trade group WIRES.

"Today's decision by the Maine Supreme Court will hopefully set the important NECEC project back on track, although with likely further delays," WIRES Executive Director Larry Gasteiger said, calling the project a "poster child for how difficult it is to get needed transmission built." ■

## ISO-NE News

# Granholm Says DOE Keeping an Eye on Winter Fuels

*By Sam Mintz*

The federal government is standing ready to help New England with fuel supply and grid reliability this winter, Energy Secretary Jennifer Granholm told the region's governors in a recent letter.

Granholm's letter came in response to the states' request for help, in which they asked the Biden administration to consider a waiver of the Jones Act for LNG deliveries, proposed a new energy reserve system for the region and asked for coordination ahead of what could be a difficult winter. (See *New England Governors Ask Feds for Help with Winter Reliability*.)

At the Department of Energy "and across the Biden administration, we recognize that the New England states face unique energy challenges, and your letter raises important areas for continued coordination and new collaboration with the administration," Granholm wrote.

Energy Secretary Jennifer Granholm wrote to New England governors to reassure them that DOE is keeping an eye on fuel supply and grid reliability. | *DOE*

She said DOE is monitoring prices and inventory levels of natural gas, gasoline and distillates, and that she has been meeting with domestic producers and refiners to talk about their inventories and preparedness for storms.

On the East Coast, inventories are 20% below the seasonal five-year average for gasoline and 47% below the seasonal five-year average for distillates. In New England, diesel inventories are 63% below their five-year average.

"These data points raise concerns about the impact of any physical disruption of supply and require that both states and the federal government are prepared to use all the tools in our toolkit to improve preparedness and respond if needed," Granholm wrote.

But while she offered general assurances that the federal government is on the case, she didn't directly agree to any of the governors' specific asks.

Granholm noted that requests to waive the Jones Act, which requires that ships hauling cargo between U.S. ports be built in the U.S., are handled by the Department of Homeland Security, and that the department would "expeditiously consider" individual waiver requests that come in. The governors had asked for a broader suspension of the Jones Act for winter LNG deliveries.

She also said that DOE "welcomes" the thoughts of governors on modernizing strategic energy reserves but gave no indication that her department is working on the subject itself.

She did say, however, that DOE and the states should "consider if a minimum fuel stock holding requirement for liquid fuels is a necessity moving forward."

FERC is leading a meeting in Vermont this week to discuss winter reliability issues in New England. (See *ISO-NE: Reliability Still Depends on Mass. LNG Import Terminal*.) ■

ISO-NE News

# NE States Seek Comment on Offshore Wind Interconnection Plan

*By Sam Mintz*

New England is getting serious about offshore wind transmission.

In a *request for information* published on Thursday, a coalition of five states — Massachusetts, Connecticut, Rhode Island, Maine and New Hampshire — asked for comments about how to connect the thousands of megawatts of offshore wind power in the development pipeline with the region's complicated, crowded grid.

The states are trying to start early, cognizant of the intense planning required for such a massive infrastructure buildout and competition for federal funding.

They also laid out an early conceptual framework for how they plan to get started, with incremental, phased additions of transmission able to handle 1,200 MW each through 2040.

"Having a clean, affordable, reliable regional electricity grid — supported by transparent decision-making processes and a transmission system that reliably accommodates duly enacted clean energy laws — is foundational to achieving our clean energy future," the states said in a statement.

In addition to comments on the plan, which are due Oct. 14, state agencies will hold a technical conference to talk in depth about the best interconnection points, how to minimize land-based transmission upgrades, the design and implementation of HVDC systems, and how to co-optimize transmission infrastructure to maximize consumer benefits.

Among the questions the group is asking for advice on are how to prioritize different projects, whether to prefer HVDC over other types of lines, and how to minimize costs to ratepayers.

The Modular Offshore Wind Integration Plan included in the RFI gets even further into the nitty gritty of where offshore transmission lines should make landfall.

"Initial assessments suggest that Bridgeport, Conn., and Boston, Mass., areas are potential efficient interconnection points for the next tranche of OSW generation," the plan says, but the states also ask for advice about other options.

The RFI and accompanying plan were met by excitement from the region's environmental groups and clean energy industry.

"New England for Offshore Wind is thrilled that five of the six New England states have come together to issue this request for information and explore investment options for the transmission infrastructure needed to integrate clean resources, including offshore wind, onto the regional power grid," said Susannah Hatch, Environmental League of Massachusetts Director of Clean Energy Policy in a statement.

## Whither Vermont?

Notably missing from the list of states involved is Vermont, but the document makes clear that the Green Mountain State, with its lack of coastline, will still be watching closely.

"Given Vermont's vertically integrated structure and the lack of any shoreline to act as a potential point of interconnection for offshore wind — which is a substantial, though not sole, focus of this RFI — Vermont will not act as a participating state," a footnote says.

"However, Vermont is generally supportive of a regionally organized effort to gather information that will aid each state's planning activities and potentially facilitate federal funding opportunities for transmission upgrades and will remain a close observer of this request for information and may participate in subsequent discussions regarding its content and/or next steps." ■

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## MISO News

# MISO Cancels Hartburg-Sabine Competitive Project

By Amanda Durish Cook

Entergy Texas' Montgomery County Power Station was cited as one of the reasons the Hartburg-Sabine line is no longer necessary. | *Entergy*

A MISO staff planning committee has determined that MISO South's only competitive transmission project, the $130 million, 500-kV Hartburg-Sabine project in East Texas, is no longer necessary.

The decision wasn't surprising. MISO has been warning for months that its analysis indicated that the project was no longer helpful to the system. (See *MISO on Verge of Cancelling Hartburg-Sabine Tx Project*.)

The project's cancellation came the day after the 5th U.S. Circuit Court of Appeals ruled on Aug. 30 that Texas' right-of-first-refusal (ROFR) law violates the U.S. Constitution's dormant Commerce Clause. (See related story, *5th Circuit Finds in Favor of NextEra's ROFR Appeal*.)

Brian Pedersen, senior manager of competitive transmission administration, said the RTO is evaluating the opinion for possible impacts to Hartburg-Sabine. However, "the opinion and order does not change the planning analysis," he told stakeholders Wednesday during a Planning Advisory Committee meeting.

Pedersen added that MISO isn't planning to conduct any more economic or reliability analyses on the project. He said studies have already shown the project has "near-zero" production cost benefits and did not uncover any transmission system issues without the line.

The grid operator said the project's benefits dissolved because of recent Entergy generation additions near the line's route. The utility brought the 993-MW Montgomery County Power Station online in 2021, and it intends to construct the 1.2-GW natural gas- and hydrogen-powered Orange County Advanced Power Station by 2026.

MISO approved the market efficiency project as part of its 2017 Transmission Expansion Plan, based on expectations it would alleviate congestion, ease import limitations and allow access to lower cost generation for customers in the chronically congested West of the Atchafalaya Basin and western load pockets in Entergy's MISO South footprint.

"It's been a little over four and a half years since the project was approved," Pedersen reminded stakeholders.

In 2018, MISO selected NextEra Energy Transmission Midwest's bid for a new 23-mile, 500-kV transmission line, four short 230-kV lines and a new 500-kV substation. NextEra's proposal beat 11 other competitors. (See *NextEra Wins Bid to Build MISO's 2nd Competitive Project*.)

However, Texas later passed a law in 2019 giving incumbent utilities ROFRs for any projects built in the state. With NextEra unable to secure permitting for construction and the 2023 in-service date approaching, MISO this year initiated its variance analysis, a process used to reanalyze projects that experience material changes. Following the analysis, the RTO had two choices: cancel the project or reassign it to a new developer.

"MISO always has deference to states' rights in these types of matters," Director Mark Johnson explained in 2019.

MISO's bid selection report is now considered moot. The grid operator now plans to file with FERC in the fourth quarter to terminate its selected-developer agreement with NextEra. ■

## MISO News

# MISO Gathering Stakeholder Input on LRTP Cost Allocation

*By Amanda Durish Cook*

MISO is collecting stakeholder suggestions on the design elements that should be included in a new cost allocation for some of the long-range transmission planning (LRTP) projects.

Milica Geissler, the RTO's cost-allocation specialist, said Aug. 30 that the goal is to create by the end of 2023 a methodology to allocate costs for the third and fourth LRTP portfolios. She said the design could be used footprint-wide or exclusively for MISO South.

During a meeting of MISO's cost-allocation stakeholder group, Geissler said staff is looking to balance "granularity, feasibility and consistency" in the cost-sharing design.

"The most accurate reading for some benefits may be at the MISO footprint or sub-regional-level," she said, advising against stakeholders expecting cost-benefit calculations at the transmission pricing-zone level.

MISO is using a 100% postage stamp rate for the first two LRTP project cycles, with those costs confined to MISO Midwest. (See *FERC OKs MISO's Bifurcated Cost-allocation Tx Design*.)

When planners begin looking for long-range projects in MISO South, the grid operator plans to use a more specific cost-allocation design. (See *MISO Seeking New Tx Cost Allocation for Major Buildout*.)

Some stakeholders have voiced concerns of disparate treatment between LRTP portfolios, saying a different cost allocation for MISO South projects will violate FERC's principle that inconsistent allocations must not be applied to the same class of projects.

At any rate, the new cost allocation might contain cost assignments for interconnecting generation in addition to load.

Darcy Neigum, with Montana-Dakota Utilities Co., proposed that the RTO impose long-range transmission costs on interconnecting intermittent resources only. He said MISO could include a new intermittent generation megawatt-hour value in the denominator when calculating LRTP project rates.

Neigum said assigning a portion of long-range transmission costs to intermittent resources would "align cost-causers and beneficiaries." He said states and utilities with carbon-reduction goals are driving the generation fleet change that necessitates the transmission in the first place.

"Not all states and loads are equal cost causers and beneficiaries," he said.

Clean Grid Alliance's Natalie McIntire raised concerns that only intermittent generators would bear the lines' costs. She said thermal generation will benefit from long-range projects as well.

McIntire also argued that the LRTP's primary purpose is to ensure grid reliability through the resource transition, and not to simply accommodate generator interconnections.

Sustainable FERC Project attorney Lauren Azar said Montana-Dakota Utilities' proposal "gave her pause."

"LRTP is not only responding to the challenges of changing grid ... but extreme weather events as well. The fact of the matter is that resilience is a goal of LRTP, and everyone in MISO Midwest will benefit," Azar said.

MISO stakeholders will next discuss LRTP cost allocation during an Oct. 18 meeting. ■

Xcel Energy line work in Northern Minnesota | *Xcel Energy*

# MISO News

## MISO Recommends Lower Distribution Factor to Address Congestion

*By Amanda Durish Cook*

Solar farm in West Baton Rouge Parish | *Entergy*

To cut down on surging system congestion, MISO is suggesting a tighter limit on new generation's effect on the surrounding grid to avoid triggering more network upgrades.

The grid operator said it might halve new generation's allotted distribution factor impact on transmission from 20% to 10% for energy resource interconnection service (ERIS), its basic level of interconnection service.

Some MISO members maintain that interconnecting generators are unacceptably increasing congestion. They say a narrower distribution factor threshold would keep runaway congestion in check by flagging a need for more transmission upgrades.

MISO *said* a preliminary analysis showed that lowering the ERIS distribution factor to 10% identified several new network upgrades in its annual interconnection queue cycles, "the majority being in the 69- to 161-kV voltage range."

Interconnection customers can either elect to secure ERIS or the higher-quality network resource interconnection service (NRIS), which ensures that a resource's entire installed capacity is deliverable. NRIS is generally more expensive than the unguaranteed ERIS.

Staff said ERIS elections by new generation "can lead to more congestion on the transmission system." They said a lower distribution factor cutoff could result in fewer system reliability issues and lead to more interconnection customers sharing in upgrade costs.

The RTO now faces billion-dollar congestion costs on a quarterly basis. Its long-term transmission plan is set to assuage some of that congestion, but the first in-service dates for the 18 new lines are at least eight years out.

MISO is again bracing for a historic level of interconnection requests in its 2022 queue cycle. During a meeting on transmission cost allocation Aug. 30, the grid operator's interconnection team estimated the RTO will field about 700 new interconnection requests, totaling about 100 GW, in a few weeks.

Staff also said they've been receiving complaints from new generators that have interconnected but cannot get their output delivered because of transmission congestion.

Some of MISO's clean energy advocates have said lowering the distribution factor threshold seems punitive to renewable energy, which accounts for most of the interconnection queue.

During a mid-August Interconnection Process Working Group (IPWG) meeting, Xcel Energy's Randy Oye said increased expenses for new generation isn't a valid argument against lowering the distribution factor threshold. He said if a project stands to affect lines by 20%, then the project's business case might need to be re-examined.

"The load is going to pay $10 billion for transmission. I think a fair question is: what should generation pay?" he said, referring to the cost of MISO's recently approved long-range transmission portfolio.

Stakeholders asked MISO for data showing that lowering the distribution factor threshold will in fact reduce congestion. They also criticized the grid operator for making a policy change in secret before bringing a proposal to a stakeholder meeting.

MISO's stakeholder community is set to again debate a stricter distribution factor during an Oct. 10 IPWG meeting. ■

## MISO News

# MISO Opening Winter Fuel Surveys Next Month


| Shutterstock

MISO this year will again ask thermal generators for information on their fuel supplies through weekly surveys and consumables data requests.

Staff will begin collecting the information Oct. 3. The recurring data requests will open each Monday and close on Sunday and can be updated throughout the week.

The RTO is collecting the data from members with units that use coal, oil and petcoke and that are registered in the commercial model. Staff have been testing the surveys.

MISO's Mike Mattox told the Reliability Subcommittee on Thursday that members' individual answers on the nine-question survey will be confidential, with aggregated data published on MISO's website.

The weekly surveys were introduced last winter after the RTO issued warnings about natural gas and coal fuel-security issues and forced-generation outages during cold fronts. (See *MISO Sounds Alarm on Potential Winter Fuel Scarcity*.) It announced early this year that the task would become permanent so it can better understand fuel positions during winter. (See *MISO Winter Fuel Security Surveys Now Permanent*.)

Mattox said the RTO still plans to turn winter fuel security surveys into a year-round task for owners of fossil fuel generation owners. However, he said fuel survey issuances "may change [in] frequency as conditions warrant."

The grid operator said last year's fuel surveys indicated generators had healthy stockpiles, despite the reliability anxiety. The RTO attributed the results to generally mild winter weather and careful fuel management. Some operators reported slower train deliveries because of supply chain issues, labor shortages and harsh weather. ■

*— Amanda Durish Cook*

MISO News

# FERC OKs MISO Seasonal Auction, Accreditation

## *Commission Rejects RTO's Minimum Capacity Obligation*

*By Amanda Durish Cook*

FERC issued a pair of orders Wednesday that allow MISO to establish a seasonal capacity auction and availability-based accreditation, but also rejected its request to require a minimum capacity obligation (*ER22-495*, *ER22-496*).

MISO Carmel, Ind., headquarters | © *RTO Insider LLC*

The commission said a seasonal auction and an availability-based accreditation will "better align resource adequacy requirements with periods of increased risks on the MISO system." However, it said the proposed minimum capacity obligation isn't likely to improve resource adequacy.

MISO in late 2021 sought FERC approval to perform four seasonal capacity auctions with separate reserve margins by the 2023/24 planning year and apply a seasonal accreditation based on a generating unit's past performance during tight system conditions.

The RTO also filed separately to establish a minimum capacity obligation, where a load-serving entity must demonstrate that it has secured at least 50% of the capacity required to meet its peak load before MISO's voluntary capacity auctions.

The commission issued the orders the day before MISO's requested Sept. 1 effective date for the new tariff rules. The grid operator has been moving ahead with preparations for the 2023/24 capacity auction while assuming FERC approval.

Most intervening stakeholders reacted negatively to the two filings earlier this year. They said a stricter accreditation based on risky hours that can't be accurately predicted would result in volatility and unfair penalties for generators. Many also said MISO didn't explain the reliability problems the minimum capacity obligation was meant to correct. (See *MISO's Seasonal Capacity Proposal Opposed at FERC*.)

But FERC said a four-season auction will provide "a more granular assessment of seasonal resource adequacy needs" and ensure that LSEs don't procure "capacity beyond what is necessary to ensure resource adequacy in a given season."

"This, combined with MISO's proposal to accredit resources based on their seasonal performance, will offer further assurance that MISO's resource adequacy provisions are sufficient to mitigate the system's resource adequacy risk throughout the planning year," the commission said.

FERC said the RTO's plan to use capacity values based on historical performance during high-risk hours "will increase MISO operator confidence that those resources will perform when they are most needed."

The seasonal accreditation design is rooted in a unit's prior performance during 65 hours of emergency or other tight seasonal system operating conditions. FERC disagreed with resource owners' complaints that the new accreditation is overly burdensome or complicated.

The commission also batted back complaints that the accreditation won't accurately predict availability during system needs. It said although "no capacity accreditation methodology can perfectly predict a resource's future availability or performance during all intervals," MISO had made an earnest effort.

But FERC also instructed MISO to complete an informational report that compares the seasonal accreditation results to actual resource availability by the end of the 2025/26 planning year.

The new seasonal design means that MISO's zones can seasonally clear beyond an annual $257/MW-day cost of new entry (CONE). The current planning resource auction design sets the maximum auction clearing price at CONE, which is calculated by dividing the new generator's costs over the days in a year. Now, CONE will be divided by the days in a season.

The grid operator has said a seasonal clearing price of up to $1,000/MW-day could be appropriate, though it promised to make sure the sum of four seasonal clearing prices for any zone remains at or below CONE.

Despite member complaints over higher clearing prices, FERC was comfortable with seasonal prices possibly exceeding an annual CONE.

"As MISO explains, such outcomes will incent new entry in the event the MISO system is short capacity," the commission said.

### Clements Objects to Seasonal Design

Commissioner Allison Clements dissented in a 19-page statement, called the seasonal design a flawed and "ambiguous proposal" whose accreditation relies on the "wrong set of hours." She said crediting resources with up to

# MISO News

12-hour lead times is unwise, given that they "are unlikely to be capable of performing when called upon."

Clements said it wasn't clear how MISO or its members would navigate four seasonal auctions held simultaneously in the spring. She said capacity sellers must blindly offer into a season without knowing any results of the other three seasons.

Allowing MISO's clearing prices to exceed CONE in a season could "provide a loophole for excessive customer costs," Clements said.

"Today's decision bakes troubling flaws into MISO's capacity rules that may jeopardize reliability for years to come. While the majority urges MISO to continue working to improve its capacity rules, it is not clear how some of these improvements could be made within the confines of MISO's stakeholder process absent Commission action forcing such an outcome," Clements said.

The commission has no reason to believe that these stakeholder dynamics will change such that MISO will better align capacity payments with system value in the future. Today's order therefore puts a flawed short-term improvement ahead of long-term results, leaving it to industry to regulate themselves," she said. "In my view, it would be better for us to insist the job is done right. 'Measure twice, cut once,' as the old adage goes."

## FERC Snubs Minimum Capacity Obligation

The commission shared stakeholders' and the Independent Market Monitor's mostly dim view of the proposed minimum capacity obligation.

It found MISO's argument that it needs a minimum obligation to discourage LSEs from relying entirely on the voluntary auction while the RTO navigates a rapidly transforming resource mix "unpersuasive." The commission said the grid operator had not demonstrated that a minimum capacity obligation "will address or mitigate resource adequacy concerns."

FERC said it was unconvinced that the obligation will reverse a trend of fading reserve margins because MISO conducts an auction six weeks before its planning year begins. It said the obligation is "highly unlikely to facilitate the construction of new resources ahead of the relevant planning year, as resources, particularly generation resources, take longer to develop than six weeks." FERC said LSEs will instead likely scramble to procure bilateral contracts from the same resources that would have otherwise offered capacity in the auction.

"Nothing inherent in the proposed MCO is likely to support the construction of new capacity in time to meet resource adequacy needs relative to the status quo," the commission said.

It also said that the RTO didn't address how the obligation would affect market power by limiting buyers' ability to purchase capacity in the auction.

"The disciplining effect of the auction, a centralized market where capacity sellers are subject to market power mitigation, on the bilateral capacity market is an important component of both MISO's resource adequacy construct and the Commission's approach to market power more broadly," FERC said.

Commissioner Mark Christie emphasized in a concurring opinion that while FERC rejected the proposed obligation, it didn't mean MISO couldn't offer a new minimum capacity obligation in the future.

In another concurrence, Commissioner James Danly said while he agreed with the market power concerns, he would have preferred FERC set the matter to a paper hearing to consider the tariff revisions. He said it appeared MISO has a "desperate need for reform of its capacity construct" combined with a difficult stakeholder process.

"I am concerned by the increasing risk that MISO will be unable to retain sufficient dispatchable generation to ensure reliability and resource adequacy," Danly said. "With these concerns in mind, I urge my colleagues to consider commission action pursuant to [the Federal Power Act] Section 206." ■

## MISO News

# Memphis Says Staying with TVA is Best Option

*By Amanda Durish Cook*

Memphis Light, Gas & Water's (MLGW) leadership said Thursday that a long-term energy contract with Tennessee Valley Authority is a safer alternative than joining MISO and simultaneously generating its own power.

MLGW President J.T. Young said during a special meeting of the utility's Board of Commissioners that staying with its current electricity supplier represents the "least risk and most value." He advised the commissioners to reject all alternative supply proposals and to schedule a future vote to consider the recommendation.

The board has up to 60 days to hold a vote. Its members said they would like to speak with TVA executives in the next month about the federal utility's long-term strategy before making their decision.

The Memphis utility has been exploring alternatives to TVA's supply since 2020 and has received 27 responses from alternative energy suppliers. In June, consulting firm GDS Associates said leaving TVA and building its own generation and transmission to participate in MISO's wholesale markets would yield the utility tens of millions of dollars each year — or place the same amount at risk. (See *Inflation Dampens Possible Memphis Exit from TVA*.)

GDS told the board Thursday that updated figures indicate none of the alternative bids produce savings when compared to TVA supply. The bids were based on MLGW's 2020 *integrated resource plan* (IRP) that envisioned multiple resource portfolios, including 230- and 500-kV links to access wholesale power in MISO South.

Chris Dawson, power supply principal for GDS Associates, said the IRP is not "immune" from inflation, more expensive labor and supply chain issues.

"I hate to keep coming back to this, but … the landscape is different than it was in 2020. … It's not the same environment that the IRP was developed in," Dawson said.

He said MLGW's "from-scratch" power alternatives to TVA will require "an immense amount of funding" and are now more expensive than remaining with TVA under a long-term, 20-year contract.

The commissioners accepted public comments at the beginning of the meeting but did not permit comment following Young's recommendation.

Memphis resident Pearl Eva Walker, climate and justice chair for the local NAACP chapter, asked that the board choose an energy supplier more focused on affordability, reducing energy burdens, and climate change mitigation.

She said GDS' analysis seemed to emphasize the risks of switching energy suppliers and ignored potential benefits. Walker said Memphis could likely take advantage of the clean energy incentives in the recent Inflation Reduction Act.

"We want a supply moving forward that will help MLGW take advantage of these tax credits," she said.

Multiple residents asked that the utility not tie itself to a supplier like TVA, which they said is shortsightedly focusing on expanding natural gas-fired resources as historic heatwaves engulfed Tennessee over the summer. (See *SACE Urges FERC Inquiry into Proposed TVA Gas Plant*.)

The Sierra Club's Dennis Lynch, who served on MLGW's Power Supply Advisory Team, said signing a long-term contract with TVA would be "the wrong direction."

Lynch called MLGW's IRP "bogus" because it relied too heavily on adding a natural gas-fired plant. He called on the utility to commission a 100% clean-energy IRP.

Other residents told the board that TVA appears to be its most reliable option, with some invoking ERCOT's disastrous outages during the February 2021 winter storm. They said Memphis must avoid a similar catastrophe.

MLGW is TVA's largest wholesale customer, comprising about 10% of total load and spending about $1 billion per year on electricity. The city has been a TVA customer for 80 years, but recently voiced displeasure over energy burdens and prices under the federal utility.

MISO this March held its quarterly Board Week in Memphis in an apparent attempt to woo MLGW. While there, the RTO's leadership met in private with the utility's executives. (See "Memphis Location for Board Week May Pay Off," *MISO Board of Director Briefs: March 24, 2022*.)

Ahead of the board meeting, the Southern Alliance for Clean Energy (SACE) accused TVA of being evasive about the extent of its dependence on MISO for energy imports.

"Without MISO, there's a good chance TVA couldn't keep the lights on in Memphis. Yet TVA continues to lead people in Memphis to believe joining MISO would threaten reliability," SACE said in a press release emailed to *RTO Insider*.

The alliance said that based on interchange data from the Energy Information Administration, TVA has imported 11% of its demand from the MISO footprint in 2022. "It's fair to say that TVA relies on MISO," SACE said, noting Memphis accounts for almost 10% of TVA's total load and imports from MISO have roughly equaled the amount of total power TVA has supplied to MLGW in recent years.

TVA's vice president of transmission and power supply Aaron Melda *pushed back* on SACE's conclusion, saying interchange and power flows do not necessarily equate to energy purchases. He said MISO also flows power over the TVA system by way of its Midwest-South transmission constraint.

Melda said TVA's 69 interconnections with other utilities means that it can and should purchase less expensive power at times to save its customers money. ■


MLGW's headquarters in Memphis, Tenn. | *MLGW*

## MISO News

# 5th Circuit Finds in Favor of NextEra's ROFR Appeal

By Tom Kleckner

A federal appeals court last week ruled that Texas' right-of-first-refusal law violates the U.S. Constitution's dormant Commerce Clause, keeping the door open for MISO and SPP competitive projects in the state's non-ERCOT footprint.

The 5th U.S. Circuit Court of Appeals found that NextEra's challenge of the 2019 law (*Senate Bill 1938*), applied to interstate markets and not ERCOT, should proceed beyond the lawsuit's pleading stage. It remanded the case back to the U.S. District Court for Western Texas (*20-50160*). (See *NextEra Appeals Court Decision on Texas ROFR Law*.)

The 5th Circuit agreed with NextEra in a 2-1 decision, released Aug. 30, that legal precedent did not shield SB 1938 from dormant Commerce Clause. The holding of the "dormant" clause is that implicit in the Constitution's grant to Congress of power over interstate commerce is a prohibition against states passing legislation that discriminates against such commerce, such as laws meant to protect a state's own economy.

NextEra Energy Capital Holdings and four other NextEra transmission owner/developer entities said in their appeal that the Texas law violated the clause because it only allowed the incumbent state owners of a transmission line's end points to build, own and operate new lines.

In rejecting NextEra's claim in February 2020, the district court said the legislation didn't discriminate against interstate commerce because it "regulates only the construction and operation of transmission lines and facilities within Texas." (See *District Court Dismisses Texas ROFR Repeal*.)

"That is wrong for the areas of Texas that are part of interstate electricity networks," the 5th Circuit said, pointing to SPP's and MISO's East Texas footprints and SPP's service territory in the Texas Panhandle.

"SPP and MISO territory … is part of an 'interconnected "grid" of near-nationwide scope' that has long been subject to FERC oversight," the court said. It noted that the commission abolished ROFR provisions in its FERC-sanctioned rate agreements with its jurisdictional RTOs and ISOs. The commission "reasoned that federal rights of first refusal might 'be leading to rates … that are unjust and unreasonable,' in large part because 'it is not in the economic self-interest of incumbent[s] to permit new entrants to develop transmission facilities,' even if those facilities 'would result in a more efficient or cost-effective solution.'"

The court also said that the Supreme Court, in finding dormant Commerce Clause violations, does not mention in which states companies are incorporated and the fact that most of Texas' in-state transmission incumbents are incorporated outside the state does not save SB 1938.

"A law can discriminate against interstate commerce even though most of the incumbent transmission line providers that benefit from SB 1938 are incorporated or headquartered outside Texas," the court said. "What matters instead is that the Texas law prevents those without a presence in the state from ever entering the portions of the interstate transmission market that cross into Texas. A law that 'discriminates among affected business entities according to the extent of their contacts with the local economy' may violate the Commerce Clause."

The ruling may not be enough to save NextEra Energy Transmission (NEET) Midwest's winning competitive bid for a $130 million, 500-kV project in East Texas. The Hartburg-Sabine project was awarded in 2018, but MISO said Wednesday that it has canceled the project because planned capacity in the region has negated much of the line's economic benefits. (See related story, *MISO Cancels Hartburg-Sabine Competitive Project*.)

NEET Southwest also applied to the Texas Public Utility Commission in 2018 to transfer ownership of 30 miles of 138-kV facilities from Rayburn Country Electric Cooperative in SPP's East Texas footprint. That application was withdrawn in 2020 after SB 1938 became law (*48071*).

The appeals court said any claims related to Hartburg-Sabine seem premature because NextEra never applied for a certificate of public convenience and necessity. It also said it would allow the district court to determine whether NextEra is entitled to any preliminary injunctive relief by suspending the ROFR while the case is pending.

It would then be up to NextEra to seek a permanent order eliminating the ROFR. NextEra did not respond to a request for comment by press time.

The 5th Circuit Court of Appeals courtroom | *Library of Congress*

The 5th Circuit's ruling lists all five Texas PUC commissioners as defendants and appellees, though none of them held their seats when NextEra filed its appeal. A PUC spokesperson said staff are reviewing the decision with its attorneys.

"The commissioners justify SB 1938's incumbency requirement as a law that promotes the safety and reliability of the electricity grid by ensuring that only those with a track record of building transmission lines in Texas can build new lines," the 5th Circuit said. "That may end up justifying the discrimination against out of-state interests, but it does not avoid the conclusion that the law discriminates. Limiting competition based on the existence or extent of a business's local foothold is the protectionism that the Commerce Clause guards against."

Circuit Judge Jennifer Walker Elrod concurred with much of the majority's opinion, noting the decision applies only "to the interstate electricity networks in Texas (but not the intrastate ERCOT network)" controlled by MISO and SPP. However, she dissented from the conclusion that SB 1938 "discriminates on its face" against interstate commerce.

"The distinction between incumbents and non-incumbents in SB 1938's text, without more, does not constitute facially discriminatory treatment of out-of-state entities," Elrod wrote. "That something more would have to be evidence of discriminatory purpose or discriminatory effect. And as the majority stated, the 'pleadings-stage dismissal of [the discriminatory-purpose and discriminatory-effect] claims was premature. Claims that turn on intent and effects typically require factual development.

"On remand, I have no doubt that the able district court will carefully analyze these thorny issues," she concluded. ■

# Storage Underestimated in NYISO 'Outlook,' MMU Says

## *Wider Deployment Could Reduce Generation, Transmission Needs*

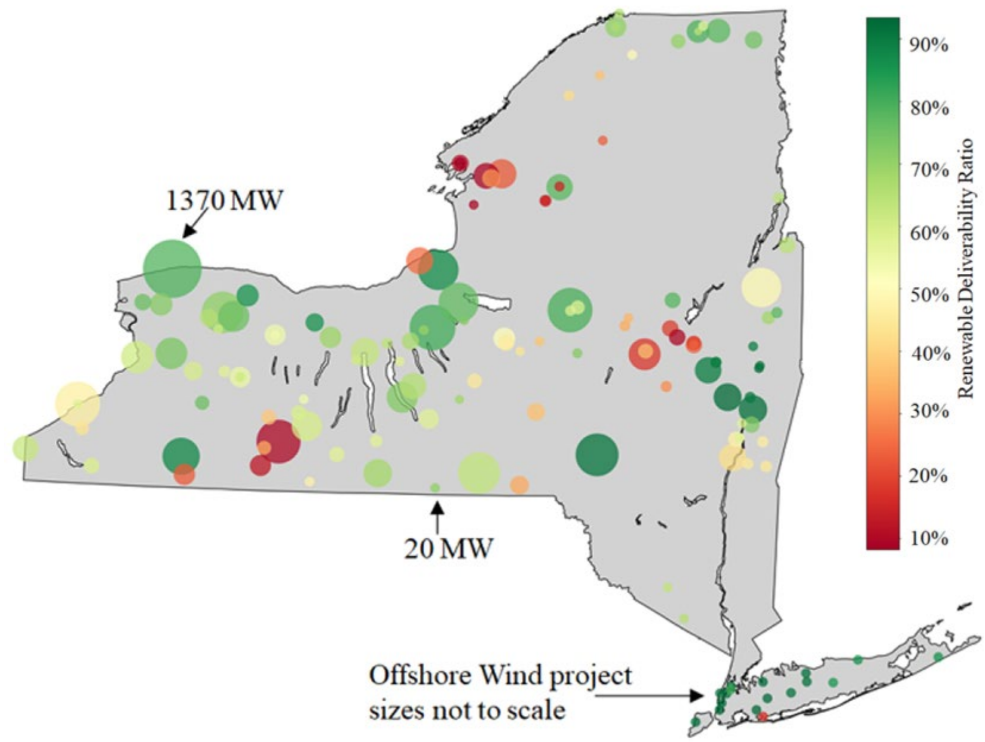
*By John Norris and Rich Heidorn Jr.*

NYISO's new long-term planning forecast is a major improvement but underestimates the role of merchant storage and increases the apparent need for transmission, according to the ISO's Market Monitoring Unit (MMU).

Potomac Economics' Joseph Coscia presented the MMU's *review* of the *System & Resource Outlook* to the ISO's Management Committee on Wednesday, before the committee recommended approval of the report to the Board of Directors. The ISO's first 20-year economic planning forecast, the outlook predicts a need for more than 95 GW of new zero-emission resources by 2040, 20 GW within the next seven years, to meet New York's goals under the Climate Leadership and Community Protection Act (CLCPA). (See *NYISO 20-Year Forecast Highlights Generation, Tx Hurdles to Climate Goals*.)

The MMU said the outlook incorporates "major enhancements" to previous economic planning studies and is "the most sophisticated forecast to date of how state policies will affect the NYISO system." But the amount of generation that the outlook says is needed could be reduced with wider deployment of storage to reduce renewables' curtailment, Coscia said in an interview.

While the outlook helps identify where new transmission could reduce congestion and make renewable energy more deliverable, the MMU said its analysis "sheds light on how NYISO's wholesale markets can facilitate more efficient clean energy investments that reduce the need for regulated transmission investments."




Renewable generators sited at many locations would be unable to deliver more than 50% of their total outputs by 2035 (yellow, orange and red circles), according to NYISO's Market Monitoring Unit. As a result, the MMU says, planners should be cautious when valuing long-term project benefits. | *Potomac Economics*

### New Terms

Potomac's analysis introduced three terms that it said would allow planners to compare the relative costs of renewable and storage resources and interconnection locations.

The "renewable deliverability ratio" is the share of an incremental resource's output that would not cause curtailment of other resources. A wind project that can produce 3,200 MWh annually and loses 300 MWh to curtailments and causes other renewables to be curtailed by 500 MWh would have a ratio of 75% (2,400/3,200 MWh).

Closely related is the "renewable deliverability impact," the megawatt-hours of renewable energy that an incremental megawatt of generation, storage or transmission capacity makes deliverable to load.

Those metrics affect the "implied net REC cost," the average renewable energy credit (REC) payment a project would need to be economic, expressed in dollars per megawatt-hour of renewable energy that it can deliver without increasing curtailments of other resources.

### Cannibalization

New renewables can be more costly than they appear because a resource receiving higher REC payments may run inefficiently and contribute to more congestion while other less costly resources are curtailed because they are receiving lower REC payments, Potomac said.

Owners of existing units who suffer this "cannibalization" — losing RECs because of increased curtailments caused by the new unit — will attempt to pass the costs to end users through higher REC prices.

As a result, Potomac said, policymakers should seek uniform pricing of clean energy to avoid undermining market efficiency.

"The value of storage and transmission projects may be distorted if the renewable energy curtailments they reduce are not valued consistently," it said.

### Incremental Storage

While new renewables can undermine existing resources by adding to congestion, storage reduces curtailments and lowers the amount of renewable capacity needed to meet New York's goals, Potomac said. It said the outlook's Scenario 2 case, which envisions high renewable penetration, underestimates storage with its assumption of 4.7 GW.

# NYISO News

"When storage resources charge to relieve curtailment of renewable resources that earn REC payments, the value of the REC is passed through to the storage owner via negative prices," the MMU said.

The implied net REC costs for land-based wind, offshore wind and solar are likely to increase between 2030 and 2035. But Potomac says net prices for four-hour storage will drop, because of its ability to increase renewables' deliverability and take advantage of higher price volatility.

Additional storage beyond the 4.7 GW would be economic based on market prices at locations where frequent curtailments and negative pricing provide substantial revenues for batteries that charge to reduce the curtailments, Potomac said.

The MMU identified 32 such locations in 2030, projecting storage's median cost there at $24/MWh. With the median cost dropping to a projected $6/MWh by 2035, that would rise to 107 locations — more than half of the total nodes modeled by the ISO.

"This suggests that the amount of storage in the outlook is inefficiently low in 2035," the MMU said.

Storage is most economic in upstate areas with low renewable deliverability ratios and least economic in New York City (Zone J) where offshore wind is expected to have higher deliverability ratios.

The outlook models assumed the location of new renewables based on projects in the current interconnection queue and did not fully consider whether the resulting mix of locations is economic or whether a different mix would be more attractive to developers, Potomac said.

"This approach is reasonable given the NYISO's limited information but runs the risk of relying too heavily on the current queue," it said, noting that the outlook's capacity expansion model does not capture congestion and prices at the nodal level.

## Recommendations for Future Outlook Modeling

Potomac recommended that NYISO perform an optimized production cost model sensitivity case with new renewables relocated to more deliverable sites and add options for two-, six- and eight-hour storage in its capacity expansion model, which is currently limited to four-hour storage.

"Longer-duration storage resources have higher capacity value and might cost-effectively provide peaking capacity in the long term while reducing curtailment of renewables," the MMU said.

The low renewable deliverability ratios at many locations in 2035 suggest that changing the location of renewable resources would reduce curtailments and increase deliverability, Potomac said.

It cited the study's projection that wind generation at the 115-kV Bennett line in Zone C will increase from 239 MW in 2030, with a 56% deliverability ratio, to 771 MW by 2035, with deliverability falling to 10%. "Many other locations across the upstate region have much better renewable deliverability ratios, indicating that it might be more efficient for some of the 771 MW of wind capacity modeled at Bennett 115 kV to be built elsewhere," Potomac said.

It acknowledged that factors such as land availability, permitting considerations and site-specific costs can cause developers to pursue projects at congested locations and that locations with high deliverability may be inaccessible or more costly.

The MMU also said the ISO's transmission planners should estimate the implied net REC cost of regulated transmission projects and compare them to alternatives including merchant battery storage and renewables.

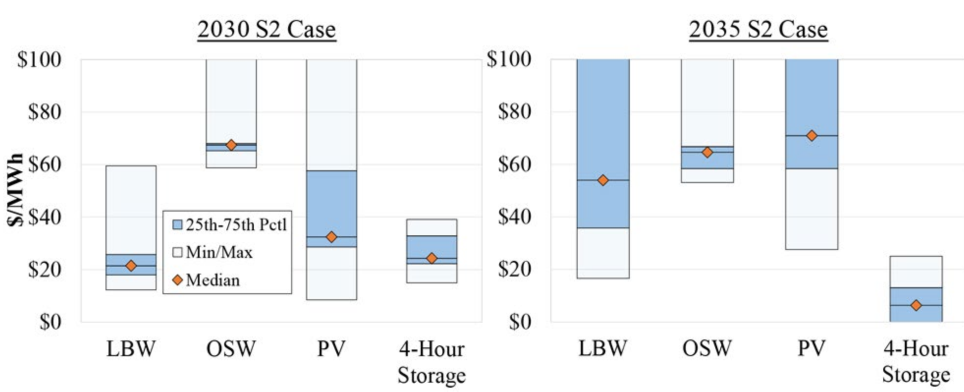
Planners should "exercise caution when evaluating benefits of transmission projects whose value is strongly linked to uncertain long-term generator siting decisions," it said. Transmission projects designed to clear constraints are more likely to be economic if selected in areas where renewables have a high probability of entering service or "superior land availability, resource potential or special cost advantages."

"Ultimately, planners should promote regulated transmission investment only when it is cost effective, since inefficient transmission investment tends to crowd out more cost-effective investments in generation and storage," Potomac said.

The MMU also raised questions about the outlook's modeling assumptions, saying it "relied on forecasts derived from currently known assumptions, which are unlikely to accurately predict how economics and policy will shape the long-term NYISO resource mix."

For example, it noted that the outlook's Scenario 2 case forecast no additional utility-scale solar until after 2030. But as the ISO was completing the outlook, the New York State Energy Research and Development Authority announced in June it had contracted for 2.4 GW in additional solar. "This suggests either that a large number of projects with state REC awards are not economic and will not enter service, or that the outlook underestimated future solar development compared to wind," Potomac said.

Potomac's Coscia praised NYISO's efforts, telling the Management Committee that the outlook includes "a lot of really key improvements." But he said planners should press for more improvements. "For studies of this magnitude, it's always an iterative process from one to the next," he said. ■




Implied net REC costs for land-based wind (LBW), offshore wind (OSW) and solar (PV) are likely to increase between 2030 and 2035 while four-hour storage will drop, making it "very cost-effective," according to NYISO's Market Monitoring Unit. The MMU defines implied net REC costs as the net cost of incremental renewable energy deliveries from an investment in generation, storage or transmission. | *Potomac Economics*

## PJM News

# Stakeholders Challenge PJM in Capacity Accreditation Talks

*By Rich Heidorn Jr.*

A long-simmering dispute over PJM's capacity accreditation of renewable resources is threatening to boil over, with some stakeholders calling for FERC intervention.

At issue is PJM's grant of capacity rights to wind and solar resources at levels that some stakeholders say have not been proven deliverable under peak conditions. The stakeholders say the practice is a reliability risk and is suppressing capacity prices. Fixing the problem could require transmission upgrades costing load up to $2 billion or more.

At a special Planning Committee meeting on capacity interconnection rights (CIRs) for effective load-carrying capability (ELCC) resources Aug. 23, stakeholders accused PJM of improperly attempting to engineer a solution in favor of lower capacity prices, while RTO officials insisted they were only trying to offer "transparency" on the impact of potential rule changes.

Economist Paul Sotkiewicz, of E-Cubed Associates, cited PJM's *presentation* at the meeting that summarized the solution proposals that had resulted from 18 prior meetings. "Some packages can delay availability of higher accreditation, which causes increased capacity costs borne by load," PJM said.

"PJM taking a market position for lower capacity costs is inappropriate at best. At worst it's begging a referral to the FERC [Enforcement] *Hotline*," said Sotkiewicz, who formerly served as PJM's chief economist.

"This is not a PJM position," PJM attorney Pauline Foley responded. "It's simply a statement of fact."

Vice President of Planning Ken Seiler said the RTO is "squeezed."

"We're trying to be as transparent as possible about the potential impact" of proposed changes, he said. "We get accused of not being transparent, and we get accused of taking a position.

"We don't care what capacity prices are," he insisted. "We care about the reliability of the system. We're not taking a position on capacity prices at all."

Seiler opened the meeting — the first by the special committee in two months — by saying the RTO had decided to "recalibrate and reset where we are" in response to stakeholder feedback in prior meetings and is not currently endorsing any package. "We as an organization are not married to any one particular package," he said.

Marji Philips of LS Power said stakeholders are frustrated that PJM has insisted there is no over-accreditation problem even as it proposes spending billions to fix it. The RTO's position "reminds me of George Orwell," she said. "I'm trying to be respectful, but that was the weirdest explanation and disinformation I've heard in a while."

But Gregory Carmean, executive director of the Organization of PJM States Inc. (OPSI), said PJM had done nothing wrong.

"It's perfectly appropriate in a cost-benefit analysis for PJM to reflect" the impact on capacity prices, he said.

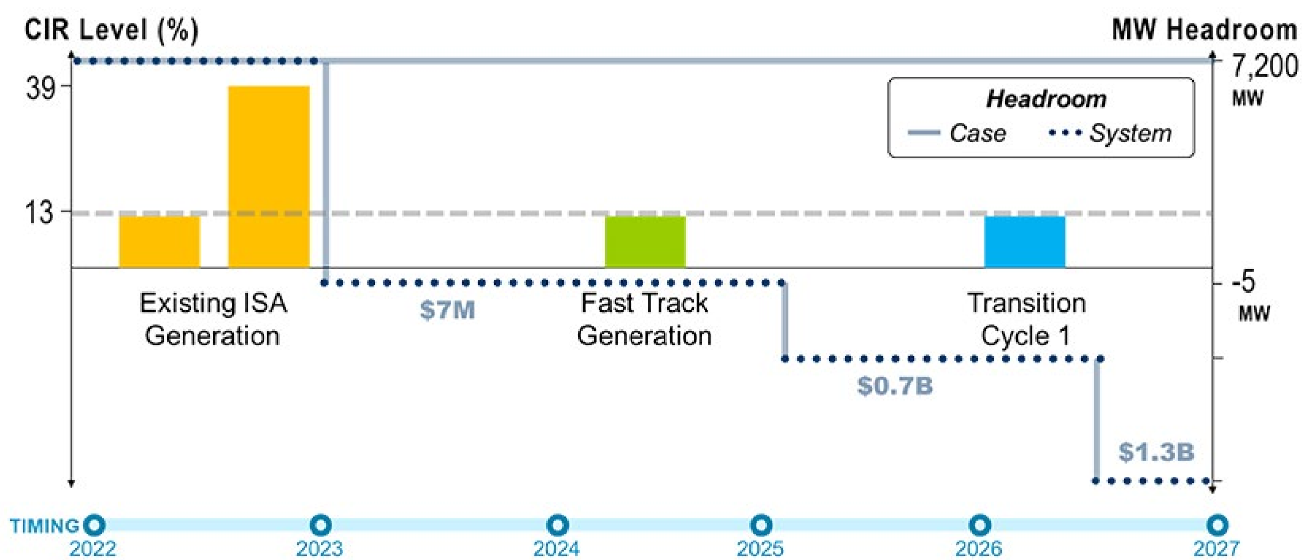
Sotkiewicz told Seiler that stakeholders were reacting to PJM staff taking "very definitive position [at a] very ugly meeting" *June 24*. "So what I think you're hearing is that blowback," he said.

That blowback has included at least one referral to the FERC hotline, according to a stakeholder who asked not to be identified. The stakeholder said two other stakeholders have also contacted the commission about what they see as tariff violations.

### Problem Statement

PJM initiated the special meetings in early 2021 with a *problem statement* calling for discussions on: "the appropriate amount of capacity interconnection rights required for existing and planned generation capacity resources; the interrelationship between CIRs and the amount of capacity offered into the capacity market; the role CIRs should play in resource adequacy considerations; and CIR retention policies that strike a proper balance between continuing to support the reliable output of the resource while not resulting in unnecessary baseline upgrades."

The initiative was proposed while PJM awaited




RTEP headroom change over time under two proposals being considered by PJM stakeholders | *PJM*

# PJM News

FERC's response to its proposed ELCC construct, which the commission approved on July 30, 2021 (*ER21-2043*). (See *FERC Accepts PJM ELCC Tariff Revisions*.) PJM uses probabilistic modeling to evaluate the contribution that ELCC resources — those such as wind and solar that are unable to maintain a stated output continuously without interruption — make to meeting PJM's loss-of-load expectation (LOLE) standard of one day in 10 years.

### Letters to Board

Economist Roy Shanker, who has represented LS Power during the committee sessions, says PJM has knowingly violated its tariff, the Reliability Assurance Agreement (RAA) and its interconnection service agreements (ISAs) by allowing renewables to sell capacity at levels above those for which they've qualified as deliverable.

The ISAs state that any output above an ELCC resource's CIRs — determined by the amount that can be delivered during peak conditions — is considered an energy resource and not eligible as capacity, Shanker and others say.

But they say PJM has knowingly allowed energy output to be sold as capacity by accrediting based on units' maximum output.

In February 2022, after a dozen meetings of the special PC committee, the PJM Power Providers Group (P3) sent a *letter* to the Board of Managers alleging the RTO was "knowingly allowing resources that cannot deliver all of their accredited capacity to acquire a capacity obligation greater than what is deliverable" at peak times.

P3 President Glen Thomas said the RTO could fix the problem by enforcing the RAA requirements with no need for a FERC filing. Instead, Thomas said, PJM proposed in the stakeholder process building transmission upgrades to increase the deliverability of the resources and to socialize the costs of the improvements.

### 'Extreme and Unjustified Intervention'

Renewable supporters, including the Solar Energy Industries Association and American Clean Power Association, *responded* that P3 was seeking an "extreme and unjustified intervention in the market" that would "circumvent the stakeholder process" based on "unproven assertions about the deliverability impact of changes in PJM's process that were made long after those resources were interconnected."

The groups countered that the board should take action "to address the profound disparate treatment in which some resources in the capacity market are now accredited recognizing fuel and weather-related correlated outage risk (ELCC resources), and the remainder (thermal resources) are not."

"To the extent that there is discrepancy between the deliverability determined through CIRs at the time resources interconnected and the ELCC capacity accreditation methodology that was adopted later, we note both that (1) this discrepancy did not take place due to any action taken by existing resources, and (2) is instead the result of adopting ELCC only for some of PJM's generation fleet," they said.

While PJM applies ELCC to wind, solar and storage, they said, thermal resources are given capacity rights up to their nameplate capacity — reduced only by the unit's equivalent forced outage rate (EFORd).

"This effectively subjects wind, solar, and storage resources to an ever-shifting capacity value based upon fleetwide entry and exit decisions," they said.

"PJM's current approach treats 93% of PJM's fleet — thermal generators — as near perfect capacity resources with no correlated outage risk. … As recent events such as Winter Storm Uri have demonstrated, this implicit assumption is demonstrably false."

At the committee's Feb. 23 meeting, PJM insisted its implementation of ELCC complies with the RAA, contending that only 5 MW of renewable generation with signed ISAs that are not yet in service may not be deliverable under proposed, higher deliverability standards. The RTO said it would cost $7 million in transmission upgrades in the 2026 Regional Transmission Expansion Plan to increase CIRs for those resources. The board echoed that position in its March 4 *response* to P3 and the environmental groups.

### Upcoming Meetings, Nonbinding Poll

PJM's Brian Chmielewski said stakeholders will be asked in a nonbinding poll to choose a solution proposal after special PC meetings scheduled for Tuesday and Sept. 23. At the Tuesday meeting, PJM will present a comparison of the six current proposals, whose cost

| | | ICAP based on Max MWH | | ICAP based on current CIR levels | |
|---|---|---|---|---|---|
| Fuel | Current ICAP (MW) | $ICAP_1$ (MW) | Percent Difference | $ICAP_2$ (MW) | Percent Difference |
| Solar | 1,818.4 | 3,563.3 | 96.0% | 1,455.6 | (20.0%) |
| Wind | 1,575.4 | 8,922.2 | 466.3% | 804.7 | (48.9%) |
| Wind & Solar | 3,393.8 | 12,485.5 | 267.9% | 2,260.3 | (33.4%) |

PJM's Independent Market Monitor says PJM has given wind and solar resources an installed capacity of 3,393.8 MW when they should only claim 2,260.3 MW based on CIR levels, an excess of 1,133 MW.| *Monitoring Analytics*

implications depend on how they are implemented in regards to the transition plan the RTO included in its June tariff filing proposing to change its interconnection process from a serial "first-come, first-served" approach to a clustered "first-ready, first-served" cycle (*ER22-2110*). (See *FERC Issues Deficiency Letter on PJM Queue Overhaul*.)

PJM says two alternative proposals before stakeholders that would not introduce the higher CIRs for wind and solar ISA holders until transition cycle 2 would result in $2 billion in baseline upgrades that would be allocated to load.

Four other proposals would result in about $700 million in costs to load by introducing the higher CIRs for wind and solar ISA holders in cycle 1 instead of cycle 2. The $1.3 billion difference would be paid by cycle 1 resources as increased network upgrade requirements, PJM said.

Shanker and others say PJM is pushing to allow existing wind and solar resources their CIRs at no cost by giving away 7,300 MW of existing "headroom" and allowing them to jump ahead of resources already in the interconnection queue. Shanker *said* PJM's $2 billion estimate "is clearly a lower bound."

The Independent Market Monitor *said* in February that PJM has given wind and solar resources an installed capacity (ICAP) of 3,393.8 MW when they should only claim 2,260.3 MW, based on CIR levels — an excess of 1,133 MW. Based on the Monitor's estimate, Shanker said he believes the practice suppressed prices in the 2022/23 Base Residual Auction by $200 million.

PJM *estimated* a slightly larger impact in June, saying that capping wind and solar at their current CIR level in the ELCC studies would reduce their capacity by about 1,300 MW. A sensitivity simulation found that removing the 1,300 MW would have cost load $230 million for the 2022/23 BRA, PJM said. ■

PJM News

# FERC Issues Deficiency Letter on PJM Queue Overhaul

*By Devin Leith-Yessian*

FERC last week issued a deficiency letter seeking more information on PJM's proposed overhaul of its interconnection queue process (*ER22-2110*).

With a ballooning backlog in its interconnection process and a sharp increase in new service requests, PJM is seeking to switch from its current "first come, first served" system to a "first ready, first served" queue. The proposal would cluster service requests together for both interconnection studies and cost allocation and advance applications making demonstrable progress toward operability. (See *PJM Files Interconnection Proposal with FERC*.)

The Aug. 30 letter from FERC's Office of Energy Market Regulation asks for further information on several points of the tariff revision, largely having to do with how the new procedures would operate and comply with past FERC orders. A response is due from PJM within 30 days.

The letter questions if grouping all applications from Oct. 1, 2021, with those received through the processing of the first new cycle could create a risk of the first wave of projects evaluated under the new system becoming "unmanageably large" and how the RTO would address that possibility.

The removal of two sections of the tariff related to reporting and penalties for PJM should it fail to complete a set percentage of transmission service request studies within a certain timeframe caught FERC's attention, with the commission seeking an explanation of how the removal would be "consistent with or superior to" the current requirements under Order 890.

The letter also seeks more information on the RTO's plan to consolidate interconnection procedures for both small and large generators.

Staff also asked the RTO to explain how it will determine whether a request for long-term firm service can be studied as part of the planning process for bulk transmission supply in PJM or whether special impact studies must be completed.

And it asked for clarification of PJM's proposal to allow a project developer to change the project site from one location to an "adjacent parcel," asking whether they must be contiguous or merely in the same geographic area.

## Tariff Revisions Supported by Stakeholders

The revisions to PJM's tariff were submitted to FERC on June 14 after receiving strong endorsement from the RTO's stakeholders in April.

The RTO has stated that its proposal is comparable to the interconnection processes employed by SPP, MISO and PacifiCorp. The new system would add multiple decision points at which applicants would be required to make readiness deposits and meet other requirements to continue.

Currently, less than 20% of applications make their way through the queue and become operational.

Not all projects drop out because of the length or difficulty of the process. Many projects are speculative "price discovery" requests submitted to determine where interconnection costs are least expensive. ■


Transmission lines crossing the Pennsylvania Turnpike | © *RTO Insider LLC*

## PJM News

# PJM Appoints Vickie VanZandt to Board of Managers

PJM has appointed Vickie VanZandt, the owner of a energy consulting firm, to its Board of Managers, according to a Friday statement from the RTO.

The president of VanZandt Electric Transmission Consulting, VanZandt will take the place of Sarah Rogers, who resigned from the board Sept. 2 after more than 10 years of service. VanZandt will begin her term Oct. 1 and will serve until at least May 2023, when she will stand for election at the RTO's Annual Meeting.

Rogers, who had been re-elected in 2021, announced her intent to retire in May. PJM's Operating Agreement stipulates that the board itself fills any vacancies until the next Annual Meeting, where members will vote on the appointment. PJM's Nominating Committee recommended VanZandt for the appointment.

In addition to her consulting work, VanZandt currently serves on the ISO-NE Board of Directors, where she chairs the System Planning and Reliability Committee. She is serving her third consecutive three-year term on that board, the maximum allowed, and it will end the same day she begins her term at PJM. (See *LaFleur Elected to ISO-NE Board*.) Her departure will bring the ISO-NE board back down to its normal 10-person membership, after having 11 for one year. (See *ISO-NE Elects Melvin Williams Jr. to Board*.)

VanZandt has previously worked at the Bonneville Power Administration as a senior vice president and chief engineer of transmission services, overseeing transmission planning, construction, operation and management. She then worked at WECC as synchrophasor program manager. ■

*— Devin Leith-Yessian*

Vickie VanZandt, PJM | *PJM*

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# SPP's Markets+ Offering Attracts 6 More Western Entities

*By Tom Kleckner*

SPP on Aug. 29 *said* that six more Pacific Northwest entities are interested in participating in the next phase of the grid operator's energy market services in the Western Interconnection.

The six organizations — Avista, Chelan County Public Utility District (Wash.), Grant County Public Utility District (Wash.), Puget Sound Energy, Tacoma Power and Canadian marketer Powerex — made their intentions public in an Aug. 19 letter to SPP, saying they intend to work with the RTO to develop a Western market that "supports reliability and delivers value to our customers."

They join Bonneville Power Administration in formally committing to funding the further development of *Markets+*, a conceptual bundle of services that would centralize day-ahead and real-time unit commitment and dispatch and provide hurdle-free transmission service.

Markets+ has been framed as a voluntary, incremental opportunity to realize market benefits by utilities that aren't ready to pursue full RTO membership. (See *BPA Commits to Funding Markets+ Development*.)

SPP said the seven entities willing to move forward with the development of Markets+ represent a "well connected footprint with extensive transmission capability, a large fleet of clean flexible hydro resources and a peak load" of over 30 GW. That is 50% larger than ISO-NE, the nation's smallest grid operator, it said.

"We are very encouraged by the governance and market design progress for Markets+ over the past several months, which has been achieved through SPP's collaborative, stakeholder-driven approach," Powerex CEO Tom Bechard said in a statement.

Powerex Managing Director Mark Holman has been one of the most vocal and inquisitive participants in SPP's Markets+ development sessions, which began late last year. The grid operator has held three in-person meetings with Western stakeholders to review work on the market's service offering and discuss outstanding items and next steps. (See *SPP Continues to Build on Markets+ Offering*.)

"By participating in this process, we are working together to build Markets+ on a strong foundation of input from Western stakeholders, ensuring the market meets the needs of the West and brings value to all participants," SPP CEO Barbara Sugg said.

A draft service offering that explains how the proposed service will address governance structure, market design, transmission availability and other items will be distributed Sept. 30, setting off a public comment period. The final service offering will be distributed Nov. 18. Interested parties will make a commitment to fund further market development in early 2023. ■


Avista's footprint in the Pacific Northwest | *Avista*

## SPP News

# Kansas Regulators Approve CCN for Competitive Project

### *NextEra Subsidiary to Build Wolf Creek-Blackberry 345-kV Line*

*By Tom Kleckner*

Kansas regulators on Aug. 30 granted a certificate of convenience and necessity to NextEra Energy Transmission (NEET) Southwest as it seeks to build a transmission line it was awarded last year through SPP's competitive process.

The Kansas Corporation Commission said in its decision the project "will have a beneficial effect on customers by lowering overall energy costs, removing inefficiency, relieving transmission congestion, and improving the reliability of the transmission system" (22-NETE-419-COC).

NEET Southwest estimates it will cost $85.2 million to build the 94-mile, 345-kV transmission line from the Wolf Creek nuclear power plant in Kansas to the Blackberry substation in Missouri. The project has a 2025 completion date.

Commission staff said the project is expected to produce a benefit-to-cost ratio of between 3.36 and 1.48 to 1.24, but that was based on an early estimate of $162.7 million in construction costs.

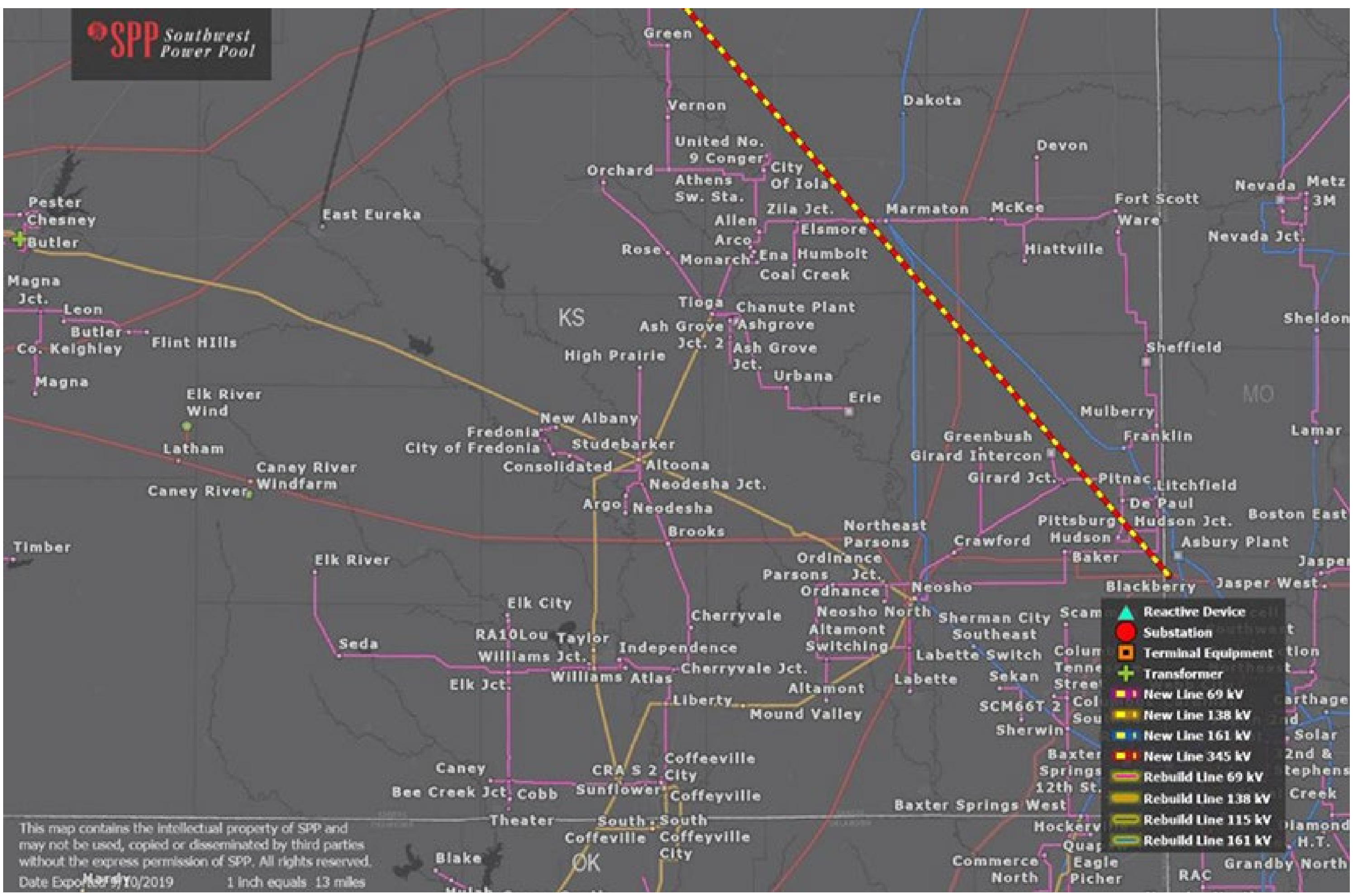
"This leads the Commission to believe the [B/C] ratio is much higher than originally projected," the KCC said.

Under the terms of a nonunanimous settlement agreement among NextEra and KCC staff, Evergy, SPP, Kansas Electric Power Cooperative, Sunflower Electric Power and Citizens' Utility Ratepayer Board, NEET Southwest will consider an option to double circuit a 25-mile segment that parallels an existing Evergy 161-kV transmission line. That is subject to receiving approval from SPP for a change in project scope and agreements from Evergy.

The KCC directed NEET Southwest to cooperate with Evergy, the incumbent transmission provider, to interconnect the transmission line to the Wolf Creek substation.

SPP's Board of Directors approved NEET Southwest's bid for the project last October. It is one of four competitive projects the grid operator has signed off on under FERC Order 1000. (See "Expert Panel Awards Competitive Project to NextEra Energy Transmission," *SPP Board of Directors/Members Committee Briefs: Oct. 26, 2021*.)

In February, FERC approved NEET Southwest's request to recover 100% of all prudently incurred costs associated with the project should it be abandoned or canceled for reasons beyond the company's control. (See *NextEra Transmission Subsidiary Gains Abandonment Approval*.) ■




The Wolf Creek-Blackberry 345-kV transmission project in Kansas and Missouri | *SPP*

# Company Briefs

## Tesla to Face California Race Bias Case

Tesla will have to face the California Civil Rights Department's race bias lawsuit after a judge denied the company's bid to toss the case.

Superior Court Judge Evelio Grillo rejected Tesla's argument that the case was improperly broad and that the state department failed to notify it of the claims or give it a chance to settle before suing. In the February lawsuit, the agency described Tesla's Fremont plant as a racially segregated workplace where black employees were harassed and discriminated against in terms of job assignments, discipline and pay. Tesla has denied any wrongdoing.

More: *Reuters*

## First Solar to Spend up to $1.2B to Expand US Production

First Solar last week said it would invest up to $1.2 billion to build its fourth factory in the U.S.

The company, which is based in Tempe, Ariz., will build the factory somewhere in the Southeast, its first outside Ohio. First Solar also said it will expand its three Ohio factories to help meet growing demand for its panels.

More: *The New York Times*

## SPARKZ to Build Battery Factory in West Virginia

Energy startup SPARKZ last week said it will build an electric battery factory that will produce cobalt-free batteries in northern West Virginia.

The batteries will be produced at a 482,000-square-foot plant in Taylor County that will employ 350 workers.

More: *The Associated Press*

## Honda, LG to Build US Battery Plant

Honda and LG Energy Solution last week announced they would jointly build a battery plant in the U.S. for a slate of new electric cars the automaker is working on.

The companies, which did not disclose how much they would invest in the plant, have yet to select a site but hope to break ground by early next year.

More: *The New York Times*

## Toyota Investing $5.6B to Build EV Batteries

Toyota last week announced plans to invest $5.6 billion in new plants to build EV batteries in Japan and the U.S.

About half the money Toyota said it plans to spend on battery production will go to expanding a plant in Liberty, N.C., which is already under construction. The investment will raise the cost of the plant from $1.3 billion to $3.8 billion.

More: *CNN Business*

# Federal Briefs

## Biden Appointees to National Infrastructure Council Include PJM CEO

President Biden announced a slate of new appointments to the National Infrastructure Advisory Council, including PJM CEO **Manu Asthana** and other prominent names in the energy sector.

Asthana is among the 26 industry and government leaders the president intends to place on the council, which "advises the White House on how to reduce physical and cyber risks and improve the security and resilience of the nation's critical infrastructure sectors."

Also appointed were: Constance Lau, who serves on the board of Associated Electric & Gas Insurance Services and formerly headed the largest public company in Hawaii, which provides electric utility to 95% of the state; Gil Quiniones, CEO of Commonwealth Edison and former head of the New York Power Authority; Audrey Zibelman, currently a vice president at X (formerly Google X), and former chair of the New York Public Service Commission and former CEO at PJM; and Pasquale Romano, CEO of electric vehicle charging network ChargePoint.

More: *The White House*

## Study: US Social Cost of Carbon Calculation Should be 3 Times Higher

A new study published in Nature last week found that the social cost of carbon should be more than three times higher than the $51 dollar figure the Biden administration currently uses.

The study comes as the administration's plans to re-evaluate the metric have stalled. One of Biden's first executive actions called for publishing a new social cost of carbon by January 2022 along with recommendations for improving the way it is calculated. Progress was delayed by lawsuits, and the administration has not announced a new timeline for the update. In the interim, the government is using a social cost of carbon of about $51, relying on the methodology used by the Obama administration. The study found that each ton of carbon dioxide emitted costs society about $185 in today's dollars.

More: *Grist*

## FERC Recommends Removal of Four Klamath Dams

FERC issued a final Environmental Impact Statement recommending the removal of the four lower Klamath River Dams along the border of Oregon and California.

"Restoring the impounded reaches to a free-flowing river would have significant beneficial effect on restoring salmon runs, access to traditional foods, Tribal cultural practices, and a characteristic fluvial landscape," the EIS said.

The draft comes nearly 20 years after a massive fish kill that left more than 60,000 salmon rotting along the banks of the Klamath River in 2002. FERC will consider the final staff recommendations of the FEIS when it issues a final ruling later this year. The project is estimated to cost about $500 million.

More: *Missoula Current*

# State Briefs

## REGIONAL

### More Than 400,000 Customers Lose Power in Indiana, Michigan

More than 400,000 customers across Michigan and Indiana lost power Aug. 29 as severe thunderstorms — with winds as high as 60 mph hour — raked the region.

DTE Energy reported more than 231,000 customers without power, while Consumers Energy reported more than 157,000 Michigan customers without service just after 7:30 p.m. Indiana Michigan Power had more than 13,000 outages across the two states. Northern Indiana Public Service said about 24,000 of its customers were affected.

As of Sept. 1, more than 100,000 DTE customers were still without power. DTE said it has about 3,000 downed lines.

More: *WTHR*; *Royal Oak Tribune*

## ARIZONA

### Residents Owe Nearly $70M on Overdue Utility Bills

Customers of SRP and APS collectively owe about $70 million in overdue residential utility bills, a report says.

According to company data, SRP customers' balances currently total $13 million. In August 2021, past due bills reached $17.3 million. Prior to the pandemic in February 2020, balances topped out at $12.6 million.

APS customers are even farther behind, as 10% its 1.2 million residential customers have overdue balances, totaling an estimated $56 million. The average amount is $470.

More: *KPHO*

## COLORADO

### Colorado Springs Utilities to Temporarily Buy Power on Open Market

Colorado Springs Utilities ended natural gas production at its Martin Drake Power Plant last week as the agency moves toward cleaner electricity generation.

CSU planned for six modular natural gas units, slated to cost $120 million, to replace the generators at Drake, but construction is running months behind due to supply chain problems. In the interim, the city will rely on purchased power.

More: *The Gazette*

## FLORIDA

### DEP Awards $68M for Electric Transit Buses

The Department of Environmental Protection last week awarded more than $68 million to secure 227 electric transit buses in 13 counties that will replace existing diesel transit buses.

The DEP also awarded grants to seven school districts to purchase 218 electric school buses.

The projects are the result of the department's Florida Beneficiary Mitigation Plan, which was created to outline how the state would spend its allotted $166 million from the Volkswagen settlement.

More: *Florida.gov*

## OREGON

### PGE to Implode Boardman Plant

Portland General Electric last week said it will implode the 656-foot stack and boiler at the utility's decommissioned Boardman coal plant on Sept. 15.

The plant came online in 1980 and was operational until 2020.

More: *KFLD*

## TEXAS

### Gas Companies to Face Fines for Failing to Prepare for Extreme Weather

The Railroad Commission last week approved new rules that would require natural gas companies to properly prepare their equipment for extreme weather or face fines up to $1 million.

The rules will require oil and gas companies to be able to continue operating during a weather emergency but do not specify the standards the agency will use to measure readiness. They will also require companies to submit annual reports to the commission outlining what they have done to ensure their facilities won't fail during weather emergencies.

A FERC report on the deep freeze in February 2021 found that 87% of unplanned generation outages were due to fuel issues related to natural gas.

More: *The Texas Tribune*

## VIRGINIA

### Zoning Board Approves Solar Facilities

The Henry County Board of Zoning Appeals last week unanimously approved a special use permit for two solar facilities.

Crowley Professional Engineers was awarded the permit to complete the Firebird and Thunderbird Solar project that intends to create two large-scale solar facilities in the Ridgeway District. The facilities would generate 5 MW and 3 MW.

More: *Martinsville Bulletin*

## National/Federal news from our other channels

*ERO Supports FERC's Extreme Weather Standards Proposal* — ERO Insider

*NERC to Request Early Adoption of Cold Weather Standards* — ERO Insider

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