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Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

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Senate Democrats OK $3.5T Spending Package After Bipartisan Accord on Infrastructure

By Rich Heidorn Jr.

| U.S. Senate

The Senate *voted* 69-30 on Aug. 10 to approve a $1.2 trillion infrastructure bill in a rare display of bipartisanship that dissolved quickly as Democrats then moved to approve a $3.5 trillion spending package by themselves.

Nineteen Republicans joined with all 50 members of the Democratic caucus in support of the infrastructure bill, which includes billions for grid improvements, alternative vehicles, existing nuclear plants and mining communities, in addition to widely supported spending on roads, bridges and ports.

The 2,702-page *Bipartisan Infrastructure Investment and Jobs Act* adds new spending of about $550 billion over fiscal years 2022-2026. (See *Bipartisan Infrastructure Bill Offers Funding for Grid, EVs*.)

Then early Wednesday, the Senate voted 50-49 to approve $3.5 trillion in climate and social welfare spending via the budget reconciliation process, which is not subject to the filibuster. House Speaker Nancy Pelosi (D-Calif.) had said she would not bring the bipartisan bill to a vote until the Senate approved the Democrats' spending bill.

Before the vote on the bipartisan bill, senators were effusive in their praise of their

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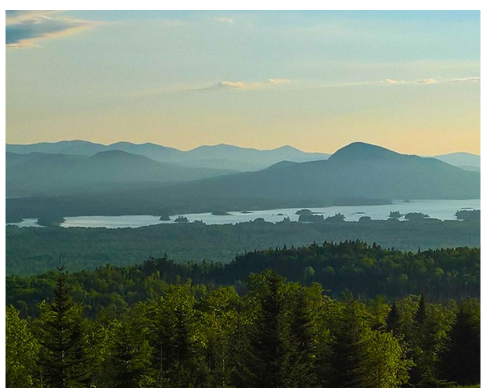
Maine Judge Vacates Public Land Lease for NECEC Tx Line

By Emily Hayes



A proposed 145-mile transmission line with the capacity to carry 1,200 MW of Canadian hydropower from the Maine-Québec border to Lewiston, Maine, is threatened by a dispute over a 1-mile corridor through state public lands in the Upper Kennebec Region of Maine, pictured above. | *Shutterstock*

A Maine judge vacated a 1-mile lease of state public land to Central Maine Power (CMP) last week, threatening the entire 145-mile New England Clean Energy Connect (NECEC) transmission corridor through the western side of the state.

The Maine Superior Court on Aug. 10 ruled that state park land, along with other land owned by the state for conservation or recreation, cannot be "reduced" or its uses "substantially altered" unless the Maine legislature approves the changes with a two-thirds majority, according to the state constitution.

The judge also concluded that the Maine Bureau of Public Lands (BPL) did not provide notice to the legislature or the public of the lease contracts.

"Given the subject matter at issue here — constitutionally protected public lands — the need for transparency and public process is heightened," the court wrote in its decision.

Continued on page 15

Tx Upgrades for PJM OSW, Renewables Could Cost $3.2 Billion

By Michael Yoder

PJM said transmission upgrades to support state renewable portfolio standards could cost upward of $3.2 billion by 2035, according to a study released last week to stakeholders.

Matthew Bernstein, a policy adviser in PJM's state government and policy department, *provided* an update on the RTO's offshore wind scenario study at the Transmission Expansion Advisory Committee meeting on Aug. 10.

Bernstein said the study, which the Organization of PJM States Inc. (OPSI) originally *requested* in late 2019, consisted of modeling five different scenarios related to the integration of renewable resources — and especially offshore wind — in PJM. The first phase of the study was intended to estimate the transmission costs required to support all the PJM states in meeting their clean energy goals.

Bernstein said the study is meant to be

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In this week's issue

***NetZero Insider* is now live!**

See p.12 for this week's coverage.

Southeast

SEEM Members Push for FERC's Decision on Market Proposal

Filing Addresses Latest Deficiency Letter

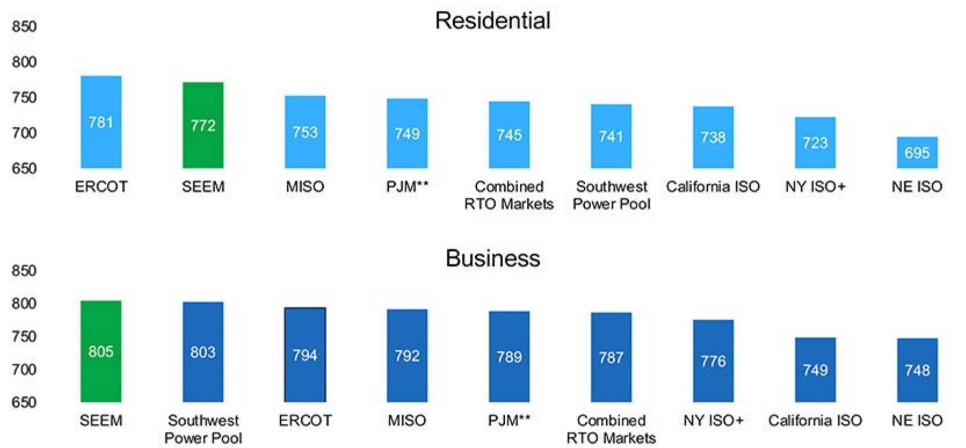
By Holden Mann

In their response to FERC's latest request for information, members of the planned *Southeast Energy Exchange Market (SEEM)* on Wednesday urged the commission to approve their proposed expansion of bilateral trading in 11 Southeastern states by next month and allow it to take effect in October (*ER21-1111*, *et al.*).

SEEM is intended to reduce trading friction by introducing automation, eliminating transmission rate pancaking, and allowing 15-minute energy transactions. Proponents, who comprise more than a dozen utilities and cooperatives in the Southeast, also claim the market would promote the integration of renewable generation resources like wind and solar.

The new filing — by a group of utilities including Alabama Power, Dominion Energy South Carolina, Louisville Gas & Electric, Georgia Power, Mississippi Power and several Duke Energy entities — answers a *deficiency letter* filed by the commission on Aug. 6. (See *SEEM Critics Repeat Call for Technical Conference*.) FERC's letter asked:

- for assurance that members will not have access to competitors' transmission function or commercially sensitive information through reports or information provided by the administrator or auditor;
- whether the availability of redacted documents posted to a dedicated confidential portion of SEEM's website would vary depending on the identity of the participant accessing the documents, in order to avoid divulging commercially sensitive information to competitors; and
- whether the administrator will be independent of members and their affiliates.



Customer satisfaction index for utilities in the proposed Southeast Energy Exchange Market compared with that of the RTO markets | *SEEM*

Members Highlight Previous Changes

In response to the first point, proponents observed that section 3.5 of the SEEM agreement "prohibits members … from providing marketing function employees with non-public transmission function information or non-public market information" received through SEEM. In addition, they reminded the commission that they had agreed to further safeguards on sensitive information in their response to the previous *deficiency letter* issued in May. (See *SEEM Members Offer Rule Changes*.)

The initial change establishes a two-step process for market auditor and SEEM administrator postings. First, any participant-specific information and critical energy infrastructure information must be redacted prior to posting a report; second, the utilities agreed to expand the restrictions on sharing non-public transmission function information and non-public market information.

SEEM members also agreed in the first deficiency response to alter the participant agreement, creating a binding contractual commitment to:

- apply information-sharing restrictions to all participants, including both jurisdictional and non-jurisdictional members; and
- bind all participants, including members, to honor the determinations of the market auditor and SEEM administrator as to information that cannot be shared with marketing function employees.

These rules are "designed to create uniformity in the application of the information-sharing restrictions," respondents said. They applied this argument to the second question as well, saying that any decision about "what information needs to be protected from marketing function employees" — including the availability of documents with redacted information on the SEEM website — will rest with the SEEM administrator and market auditor. Participants will be contractually obligated not to share such information with unauthorized individuals.

In response to the third question, SEEM members clarified that the administrator "will not be a member, participant, agent, or the market auditor, nor an affiliate of those entities."

Quick Decision Requested After 'Narrow' Inquiry

Noting the "limited nature" of the commission's request compared to the previous deficiency letter, which ran to 14 pages with 12 detailed questions, the respondents suggested FERC shorten the standard comment period to 10 days in addition to accelerating the approval and effective date for the SEEM member agreement.

"The requested expedited action is necessary if the [SEEM] members are to stay on track to bring the benefits of [SEEM] to customers during the first half of 2022," the filing said. "Further delay of commission action may push the implementation … into the third quarter of 2022, which would delay the cost savings benefits for customers."

Neither FERC's deficiency letter nor the SEEM members' response directly mentioned the July 29 filing by several environmental groups that have criticized the proposed market on several previous occasions. However, Wednesday's filing said that to facilitate FERC's consideration of their response, SEEM proponents "will not answer any protests again rehashing issues outside the scope of the proceeding, or previously addressed." ■

FERC/Federal News

Senate Democrats OK $3.5T Spending Package After Bipartisan Accord on Infrastructure

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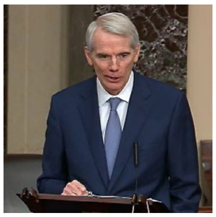
staffs and their fellow senators across the aisle. Sen. Rob Portman (R-Ohio) thanked Sen. Kyrsten Sinema (D-Ariz.), with whom he began meeting more than four months ago to "lay the foundation for our path forward."



Sen. Rob Portman (R-Ohio) | *U.S. Senate*

"I commend her for her leadership, for her courage and for her ability to keep us on track during some tough times during this process," Portman said.

He said almost three-quarters of the pages in the bill were from legislation previously passed in the Senate or its committees, calling it "a tribute to the quiet bipartisanship that goes on at the committee level."

He also noted that more than 100 industry associations, unions and trade groups endorsed the legislation, including the Chamber of Commerce, the Business Roundtable and the National Association of Manufacturers from business, and the AFL-CIO and the Teamsters from labor.

Sen. Shelley Moore Capito (R-W.Va.), the ranking member of the Environment and Public Works Committee, thanked committee Chair Tom Carper (D-Del.), who she said steered committee approval of two infrastructure packages that formed "the foundation" of the bill. "He has been great in managing this bill on the floor but also [keeping] the guardrails on what we established to make sure that … the bipartisan group was following along with what the committee had unanimously passed."

Majority Leader Chuck Schumer (D-N.Y.) also thanked the Republicans who signed on to what he called "the most robust injection of funds into infrastructure in decades."

Then he quickly turned to the Democrats' spending bill.

"The bipartisan infrastructure bill is a very significant bill, but our country has other very significant, very important challenges." Schumer said. "So to my colleagues concerned that this does not do enough on climate, for families and for making corporations and the rich pay their fair share, we are moving on to a second track which will make generational transformation in these areas."

Reaction

The Business Council for Sustainable Energy praised the passage of the bipartisan bill while also calling for approval of the Democrats' budget measure, saying "policymakers should keep the findings of this week's [U.N.] report top of mind." (See *Too Late to Stop Climate Change, UN Report Says*.)

The American Council on Renewable Energy released a *letter* signed by 186 House Democrats endorsing long-term extensions and expansions to the production tax credit; an investment tax credit (ITC) to help meet President Biden's target of a carbon-free power sector by 2035; modernization of tax incentives for commercial and residential energy efficiency and residential electrification; incentives for clean transportation and alternative fuel infrastructure; and a direct pay option to aid financing of energy projects whose sponsors can't take advantage of tax credits.

On Wednesday, ACORE also released a *letter* from it and more than four dozen utilities, renewable energy companies, transmission developers, environmental organizations, and business and labor groups urging Congress to include an ITC for "regionally significant" transmission in the budget bill. The groups said the bipartisan bill "no longer addresses the interregional, interstate highway-type lines for which the current U.S. regulatory structure has no functioning means of cost recovery."

"Even if the Federal Energy Regulatory Commission decides to act on its own authority in this area, that process has historically been time-consuming, characterized by significant uncertainty and subject to lengthy judicial review," they continued. "A federal transmission ITC would give private capital the certainty it needs now to invest in the national, high-priority lines that will serve as the backbone for America's clean energy grid."

Edison Electric Institute President Tom Kuhn called the bill's $7.5 billion for electric vehicle charging infrastructure and $7.5 billion for low- to zero-emissions buses and ferries "a good down payment on the electric vehicle charging infrastructure and low/no-emission buses that we need to accelerate the electrification of the transportation sector."

The Bipartisan Policy Center (BPC) praised the bill for appropriating funding for demonstration projects authorized under the Energy Act of 2020, including energy storage, carbon capture, direct air capture, renewable energy and advanced nuclear reactors. The BPC also highlighted funding to aid the offshore wind industry and the Department of Transportation's Port Infrastructure Development Program and Marine Highways Program.

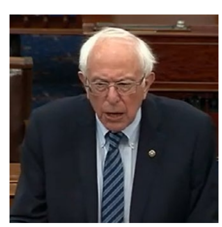
The Carbon Capture Coalition joined the BPC in endorsing provisions to build out CO_2 pipeline infrastructure through the SCALE Act and funding of carbon capture, utilization and storage.

The National Rural Electric Cooperative Association praised the bill's support for public-private partnerships to improve physical and cybersecurity but called for additional assistance for rural communities.

"As policymakers plan for a future that depends on electricity as the primary energy source for much of the economy, more work will be needed to build on this infrastructure down payment," NRECA CEO Jim Matheson said. "Electric co-ops will continue pushing for the financial flexibility to refinance existing government loans at today's low interest rates and eligibility for direct pay tax credits to boost electric co-op investments in renewables and other innovative energy technologies."

The Alliance to Save Energy highlighted $65 billion for grid modernization and $3.5 billion for the Weatherization Assistance Program.

Reconciliation Package



Sen. Bernie Sanders (I-Vt.) | *C-SPAN*

Schumer called for action on the *reconciliation bill* immediately after the vote on the bipartisan bill was tallied. His motion to begin debate was approved 50-49.

The debate over the bill began with Sen. Bernie Sanders (I-Vt.),

FERC/Federal News

chair of the Budget Committee, laying out his case for the additional spending.

"At a time when California is on fire, when Oregon is on fire, when Greece is burning and when countries throughout the world are experiencing unprecedented drought which will clearly impact food production, this legislation begins the process of combatting climate change so that our kids and grandchildren can live in a country and a planet which is healthy and habitable," Sanders said. "It would be immoral and an absolute dereliction of our responsibilities as elected officials to do anything less. We cannot ignore climate change any longer. Now is the time for our great country to lead the world out of this existential crisis."

Sen. Lindsey Graham (R-S.C.), the ranking member on the committee, responded by calling the bill a socialist Trojan horse that would result in increased gasoline and home heating costs and a flood of illegal immigrants.

"If you implement the provisions of this budget resolution regarding climate change, you're declaring war on the internal combustion engine; you are going to shut down coal-fired plants," he said. "I believe in climate change, and I'd like to have a rational approach to solving the problem, but this is not rational. ... So yes sir, we're going to have one hell of a fight."

The reconciliation bill lays out a framework for the federal budget. Its details will not be determined until Congress enacts additional legislation to flesh out the outline. The House is expected to begin work on the legislation when it returns from its recess on Aug. 23.

It is expected to include $300 billion in clean energy spending, including additional funding for EVs in support of Biden's Aug. 5 executive order calling for 50% of cars sold in 2030 to be electric or hybrid. (See *Biden Executive Order Sets 50% EV Goal by 2030*.)

ClearView Energy Partners told its clients Aug. 5 the reconciliation legislation could provide more than $100 billion for EV manufacturing and purchase incentives plus another $100 billion for solar, wind and advanced manufacturing.

A White House *fact sheet* issued Aug. 5 highlighted the administration's "Build Back Better" priorities beyond the bipartisan deal, calling for extending and expanding clean energy and EV tax credits.

It also listed creation of an energy efficiency and clean electricity standard and a Civilian Climate Corps to work on conserving public lands and waters and improving community resilience.

Votes on Amendments

Members then worked into Wednesday morning with voting on amendments to the reconciliation, beginning with a 99-0 vote in favor of *one* by Sen. John Barrasso (R-Wyo.) that would prohibit "legislation or regulations to implement the Green New Deal."

Sanders said he could support it because "it has nothing to do with the Green New Deal."

President Biden took a drive in an electric Jeep on Aug.5 after issuing an executive order for 50% of cars sold in 2030 be electric or hybrid. | *The White House*

"Despite what Sen. Barrasso says, the Green New Deal would not shift jobs overseas. In fact, it will create millions of good-paying jobs in the United States of America. It will not raise electricity prices. It will not make the U.S. dependent on dirty sources of energy from other countries."

Many other votes were along party lines, with Democrats backing one by Sen. Carper to create a reserve fund "relating to addressing the crisis of climate change" and rejecting Republican amendments to block stepped up tax enforcement and cancel the Biden administration's ban on new oil and gas leases on federal land.

In all, the Senate considered 41 amendments on issues including abortion, immigration, police hiring and taxes before approving the reconciliation about 4 a.m. with no Republican support. One Republican, Sen. Mike Rounds (S.D.), did not vote.

Energy amendments approved included a fund for "preventing electricity blackouts and improving electricity reliability" (52-47) and a means test to prevent high-income individuals from getting subsidies for luxury EVs (51-48).

Also approved were amendments:

- prohibiting federal funding for renewable energy projects using materials, technology and critical minerals from China (90-9);
- barring the Council on Environmental Quality and EPA from promulgating rules or guidance banning hydraulic fracturing (57-42);
- preventing the Department of Agriculture from making fossil fuel generation ineligible for financing (53-46); and
- prohibiting or limiting the issuance of "costly" Clean Air Act permit requirements on farmers and ranchers or the imposition of new federal methane regulations on livestock (66-33).

Following the votes, Schumer said the Democrats' budget "will bring a generational transformation for how our economy works for average Americans."

Progressives are likely to face opposition on some spending from Sens. Sinema and Joe Manchin (D-W.Va.), the latter the chair of the Energy and Natural Resources Committee, who have both expressed opposition to the $3.5 trillion price tag. With Republicans united in opposition, Democrats can't afford to lose a single vote on the final spending package. ■

CAISO/West News

Calif. Renewables Could Cover 813,000 Acres

Huge Land Area Needed for New Solar, Wind and Geothermal Generation

By Hudson Sangree

California's push toward 100% clean energy by 2045 will require building solar arrays, wind farms and other infrastructure on more than 1,270 square miles of in-state land, an area about the size of the cities of Los Angeles, San Diego and San Francisco combined.

Scott Flint, manager of renewable energy policy and planning at the California Energy Commission, on Thursday *told* leaders of the CEC, the California Public Utilities Commission and CAISO that utility-scale solar arrays will cover the largest share of that area at nearly 600,000 acres to accommodate 85 GW of new generation and storage by 2045.

Wind farms will require more than 200,000 acres for 5,000 MW of capacity, and geothermal plants will take up almost 12,000 acres for 2,300 MW. The total area needed for new renewables is 813,319 acres, Flint said.

The CEC has been developing maps that show optimal locations for the resources along with protected lands, prime farmland and areas important for biodiversity, Flint said.

The goal is to make that information readily available to CAISO for long-term transmission planning and to other state agencies responsible for siting generating resources.

"For purposes of the ISO's 20-year transmission look, we are going to hand them a map," Flint said. "This map will help them in deciding where to assign resources."

Most solar arrays will likely be built in the Mojave Desert, areas of the San Joaquin Valley and its surrounding hills that are less desirable for farming, and on the Carrizo Plain, a vast flat valley traversed by the San Andreas Fault in Central California.

Wind turbines must be scattered around the state in wind-prone areas such as the North Coast and Tehachapi Mountains.

The process of acquiring and building on so much land is rife with the potential for conflicts with farmers, environmentalists, the state and federal governments and local communities, Flint acknowledged. Mapping potential zones of conflict and off-limits areas in advance will help avoid long legal battles.

"It helps to accelerate the overall process of deployment," he said.

Thursday's resource build workshop was the third in a series of joint sessions intended to determine the requirements for generation, transmission and land needed to meet the mandates of Senate Bill 100. The landmark 2018 measure, signed by then-Gov. Jerry Brown, requires the state's load serving entities to serve retail customers with 60% renewable energy by 2030 and 100% carbon-free energy by 2045.

Prior workshops and reports found California needs to triple its in-state generating capacity and embark on a program of transmission construction to meet the ambitious mandates. (See *Calif. Needs New Tx for 100% Clean Energy* and *Calif. Must Triple Capacity to Reach 100% Clean Energy*.)

The state must build 6 GW of new generation per year — compared with the 1 GW it built in 2019 — for each of the next 25 years, a report by the CEC, the CPUC and the California Air Resources Board found. ■

The state needs vast solar arrays in the Mojave Desert and San Joaquin Valley to reach its goals. | *First Solar*

CAISO/West News

CAISO 2020 Load Costs Rise Despite Gas Price Decline

By Robert Mullin

Low hydroelectric output, a summer heat wave and high prices during evening ramps helped boost CAISO's load-serving costs by 3% last year despite "substantially lower" natural gas prices, the ISO's Department of Market Monitoring (DMM) found.

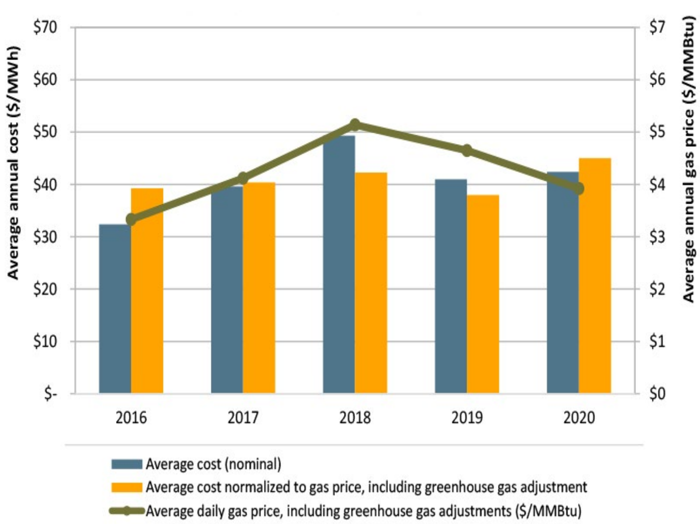
CAISO's total wholesale energy costs hit $8.9 billion in 2020, translating into $42/MWh, up from $41/MWh a year earlier, the DMM said in its *2020 Annual Report on Market Issues & Performance*.

When adjusted for the decline in natural gas prices and changes in greenhouse gas costs, the ISO's wholesale costs increased by 19% per MWh last year, Amelia Blanke, DMM manager of monitoring and reporting said Thursday during a call to discuss the report.

"Within the ISO, the cost for gas, which includes greenhouse gas costs, fell by about 15.7% on a weighted basis," Blanke said. Gas-fired resources tend sit on the margins of the CAISO market, setting the price for energy.

Hydroelectric generation accounted for about 8% of the ISO's total supply last year, compared with 14% in 2019, 10% in 2018 and 15% in 2017. Average hydro output this year has been lower than last year in every month but March, Blanke said.

"This has a major impact on prices in our market as our hydro generation tends to be towards the bottom of the bid stack," she said.



The cost to serve CAISO load increased last year despite a sharp decline in average natural gas prices. | *CAISO Department of Market Monitoring*

Wholesale power prices were lower in the first and second quarters of last year than in 2019 as COVID-19 restrictions began to take shape. Prices in the day-ahead, 15-minute and five-minute markets were all about 45% lower year-over-year in the first quarter, dipping to their lowest levels in the second quarter (typical for the ISO), and then ramping up in the third quarter due, in part, to an August heat wave. And while prices in all three markets converged closely during the first two quarters, they diverged in the second half, with day-ahead and 15-minute prices exceeding real-time by about 20% on average.

The reduced output from hydro plants and "extreme" summer loads also caused CAISO's market to become structurally uncompetitive for more hours than in any of the past five years. "Despite this, prices were consistent with competitive baseline levels," the DMM said.

The DMM also found that "the market for capacity to meet local resource adequacy capacity continues to be structurally uncompetitive in most local areas."

The report pointed to other factors contributing to last year's rising costs:

- Transmission congestion costs increased, particularly related to limits on lines linking Northern and Southern California.
- Ancillary service costs jumped to $199 million from $148 million in 2019 and $177 million in 2018, driven by higher regulation and operating reserve requirements and increased third- and fourth-quarter prices.
- Real-time imbalance offset costs increased to $177 million from $105 million a year earlier. Congestion offset costs accounted for $117 million of that amount. "As in 2018, congestion offset costs were caused largely by significant reductions in constraint limits made by grid operators in the 15-minute market relative to higher limits in the day-ahead," the report said.
- Bid cost recovery — or make-whole — payments rose by $3 million to $126 million, representing 1.4% of total energy costs.

CRR Losses Continue to Mount

The DMM estimated that CAISO last year paid out $70 million more in congestion revenue rights (CRRs) than it took in from its CRR auctions, continuing a pattern that has been in place since the ISO began holding the auctions. A staunch critic of the CRR auction program, the DMM says it has saddled California ratepayers with $800 million in costs since 2012 without providing them any benefit. The Monitor contends that ratepayers are unwitting participants in a process that mostly enriches sophisticated "financial entities" that own no physical generation.

CRR losses had fallen sharply to $26 million in 2019 after the ISO implemented rule changes intended to reduce revenue deficiencies from the auctions. (See *FERC OKs CAISO Plan to Deal with CRR Shortfalls*.) The DMM attributed last year's increase to a small number of load-serving entities selling their allocated rights to third parties, making them subject to payouts.

During Thursday's call, Blanke reiterated the DMM's call for the ISO to altogether disband the auctions, prompting a testy exchange with Seth Cochran, director of market affairs for CRR trader DC Energy.

Cochran urged the DMM to consider the findings of a recent London Economics International *report* that concluded that PJM's financial transmission rights market is providing certain exogenous benefits to the broader wholesale market that the DMM is not capturing in its assessment of CAISO's CRR market.

"This is a fairly direct calculation of the ratepayer losses. We're not attempting in this to capture any kind of exogenous benefits from hedging," Blanke responded.

"Can the [DMM] slides be annotated to reflect that? That would be an important [acknowledgement] to that slide," Cochran said.

"If the benefits of hedging are so great, then I think we've recommended the ISO should just run a market between willing buyers and sellers for hedging. You know, eliminate CRRs and just replace it with a straightforward hedging market," DMM Executive Director Eric Hildebrandt said.

"If you read the report, you'd understand the liquidity needed to get those benefits comes from having hedges sold in the network configuration. So, to separate the two is not quite the way that that would work or play out in the real world," Cochran responded.

Looking Ahead — and Back

Speaking about longer-term trends, Blanke said that day-ahead energy costs are steadily declining as a share of wholesale market costs in CAISO, falling from 95% in 2016 to 91% last year.

"More of that is coming from an increase in real-time energy costs, which include costs for the flexible ramping product," Blanke said.

Blanke also noted that community choice aggregators account for 30% of CAISO load, up from 2% in 2015.

"With that shift, we've seen an increase in the amount of long-term power purchase agreements ... which really provided a basis for a lot of the competitive bidding that we've seen in our market," she said.

Blanke also pointed to the continuing growth of renewable resources participating in the market in response to state mandates and carbon emissions reduction targets.

"We're also seeing the impact in terms of the kind of weather extremes, which are becoming more common in the market footprint, especially across the wider Energy Imbalance Market footprint," she said.

Blanke said the DMM's findings regarding last August's rolling blackouts in CAISO — the first for California in 20 years — match those from a joint, root cause analysis issued by the ISO, the California Public Utilities Commission and the state's Energy Commission. (See *CAISO Issues Final Report on August Blackouts*.) Causes included extreme temperatures and energy demand across the West, insufficient resource adequacy requirements, faulty accounting rules that overestimated RA capacity, a derate on an intertie from the Pacific Northwest, and unexpected loss of key gas-fired resources. ■

Wash. Pumped Hydro Project Faces Permitting, Obstacles

By John Stang

Washington's first pumped storage generator is expected to go online between 2028 and 2030, if it can obtain the needed state and federal approvals.

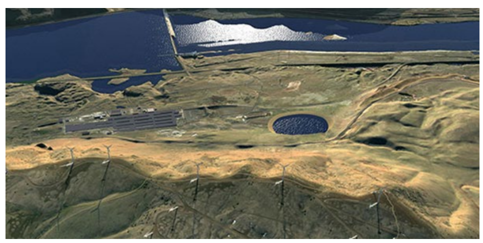
The project is designed to generate 1,200 MW, which is the roughly the same amount of electricity produced by a full-size nuclear power reactor.

While the pumped storage concept has been around for decades, it is just emerging in the Pacific Northwest. "It's a tried-and-true technique and has been around for a hundred years," Erik Steimle, Rye Development's vice president of project development, told *RTO Insider*.

The privately owned $2 billion project would be located at the top and bottom of the cliffs of the Columbia River Gorge in sparsely inhabited Klickitat County, near the John Day Dam.

The developer, Rye Development of Boston, plans to build two lined 600-acre reservoirs separated by 2,100 feet in elevation. One reservoir will be on the river shore and the other at the top of the cliff. Underground pipes will connect the two reservoirs with a subterranean generating station along the channel. Water will flow from the upper reservoir to the lower one to power the generator, and then will be pumped back up to the upper reservoir in a closed-loop system.

The project will use water purchased from Klickitat County Public Utility District, which



The proposed pumped hydro project would use a lower and upper reservoir above the John Day Dam on the Columbia River. | *Washington Department of Ecology*

owns a 15,591-acre-foot/year water right gifted by the former Columbia Gorge Aluminum smelter.

Rye Development has 22 projects east of the Mississippi River that involve converting non-powered dams into hydroelectric dams. West of the Mississippi, it is also developing a similar 400 MW pumped storage project at Swan Lake in southern Oregon. The two Northwest projects together will be capable of storing 12 hours of energy, giving them flexibility in providing electricity to the region's power grid.

The $800 million Swan Lake project is scheduled to go online in 2026.

Klickitat County's government has been pursuing renewable energy projects for a couple decades. At least two solar farms are in the works and eight wind turbine projects have been or are being built. "This is a vision of the community of Goldendale [the county seat]," Steimle said.

The Klickitat project is in the permitting stage. It is halfway through a State Environmental Policy Act review and is advancing toward a FERC permit. In June, the Washington Department of Ecology rejected Rye's application for a 401 Water Quality permit, due to insufficient information, but is allowing Rye to resubmit the application.

Steimle said Rye expected the rejection for insufficient information and plans to resubmit the application.

The project faces a pair of local obstacles.

One is the former aluminum smelter at the lower reservoir site that various corporations operated from 1969 to 2003. Smelter operations contaminated the soil and groundwater at the site with fluoride, polycyclic aromatic hydrocarbons, cyanide and polychlorinated biphenyls. Rye's development plans would deal with that pollution.

Also, the Yakama Indian Nation opposes the project because the land includes a longhouse, an ancient village site and sacred sites. Columbia Riverkeeper, Washington Chapter of the Sierra Club, American Rivers and Washington Environmental Council are supporting the Yakamas' stance.

Rye is in talks to resolve the Yakamas' concerns. "We understand the importance of finding ways of working with tribes collaboratively," Steimle said.

Steimle does not expect the permitting issues to be resolved until late 2022 or early 2023. That would likely be followed by 18 to 24 months of engineering and other preconstruction work. Construction is expected to take four years. ■

ERCOT News

Texas PUC Faces Sticky Issue in Setting Weather Rules

By Tom Kleckner

Texas regulators are grappling with writing weather preparedness measures for generators and transmission service providers as required by state law, a task that sounds easy enough until put into practice.

Several factors are hampering the Public Utility Commission's work. There's a required, in-depth study of extreme weather scenarios that is not expected to be completed in time to meet the commission's Dec. 1 deadline for a final rulemaking.

There's also a pending federal regulatory standard for generators that's still almost two years away. And then there's the harsh reality that not all generating units run or are operated the same way, a complication when writing a weatherization rule for a fleet with tens of thousands of individual units.

Barksdale English, the PUC's director of compliance and enforcement, said Thursday that staff's *draft rulemaking* is procedurally on track, although the short implementation deadline is a "big challenge."

"We have six months to write a rule the commission has never taken up before and that it has never regulated," English told the commissioners during a PUC work session on weatherization.

He said the proposed rule will tackle the statutory requirement that generators be prepared to operate during a weather emergency. "We have to think about what a reliability standard is, what it means to be prepared to operate during extreme weather," he said.

According to the draft rule, ERCOT must conduct the weather study and include statistical probabilities for a range of weather scenarios in the 95th, 98th and 99th percentile probabilities. The study must address a comprehensive range of weather scenarios and must include minimum parameters for high and low temperatures, wind, humidity, precipitation and duration.

Generators must comply with either a basic or "enhanced" weather reliability standard. The basic standard requires a generator to maintain preparation measures that "reasonably ensure" it can operate at its rated capability, as defined by ERCOT under the 95th percentile of each of the weather study's four extreme scenarios. The enhanced standard

Texas PUC Chair Peter Lake (right) swears in Jimmy Glotfelty, aided by his mother, as the commission's newest member. | *Texas PUC*

raises that threshold to the 98th percentile.

Separate standards are included for new generators and black start providers. Each generation entity is required to submit to ERCOT a study that confirms compliance with the standard and to also file an annual report to the grid operator. ERCOT must develop an inspection program that ensures each resource is inspected at least once every three years.

This fall, ERCOT plans to conduct spot checks for "every plant that had problems" during the February winter storm.

Woody Rickerson, the grid operator's vice president of grid planning and operations, said staff has noted improvements at plants that failed during a 2011 winter event. That storm led to legislative directives that were never followed up on.

"We did see improvement before 2021," Rickerson said.

"The only thing is, we didn't have anything on paper," Commissioner Will McAdams said. "Once you have something on paper, that's a different animal."

Without a complete weather study, the commission agreed to draft an initial set of rules and then finetune the requirements once it has the weatherization data and analysis. The initial standard will apply to those generating units that failed during the 2011 and 2021 winter storms.

"Make a plan to fix those and execute that plan," English said, noting ERCOT will gain regulatory authority from the new rule. "So actually prepare your facility. Don't just tell me that you identified the problem, but do something about it."

More than 30 entities have provided comments on the proposed rulemaking.

The work session was the first of six scheduled workshops as the PUC manages the work of turning legislation and political directives into grid protocols and requirements (*51617*). (See "Regulators Set Future Work Sessions," *Texas Public Utility Commission Briefs: July 15, 2021*.)

Texas climatologist John Nielsen-Gammon and Chris Coleman, ERCOT's meteorologist, set the stage with an informational discussion on the state's climate. Thermal and renewable generation experts and natural gas industry representatives discussed weatherization best practices and their lessons learned.

Joseph Younger, the Texas Reliability Entity's director of enforcement, reliability standards and registration, said NERC's cold weather standard remains under development, but was filed with FERC on June 17. Assuming FERC approval of Project 2019-06 and its mandatory cold weather preparedness requirements, he said the standard would not become effective for another 18 months.

The project, initiated after the 2018 cold weather event involving SPP and MISO, requires generator operators to protect their units against freezing and share their cold weather operating parameters with regulators. (See *NERC Board OKs Cold Weather Standards*.)

"The 2021 event could be folded into the standard through a FERC directive," Younger said.

"NERC has a knack of doing things just in time," Commissioner Jimmy Glotfelty said in making his first official appearance on the PUC.

Glotfelty, co-founder of Clean Line Energy Partners and a former Department of Energy official, was appointed to the PUC on Aug. 6, giving the commission a fourth member for the first time. State lawmakers passed legislation earlier this year that increased the PUC's membership to five. (See *Abbott Names Glotfelty as 4th Commissioner on Texas PUC*.) ■

ERCOT News

ERCOT Board of Directors Briefs: Aug. 10, 2021

Jones Defends Roadmap to Grid Reliability, TAC Shakeup

What began as another hum-drum CEO's report to ERCOT's Board of Directors last week devolved into a battle over words between interim CEO Brad Jones and Director Shannon McClendon, who represents the market's retail electric provider (REP) segment.


Shannon McClendon, Demand Control 2 | *Ballotpedia*

Speaking for her members — "I've got a segment that is really chewing on me," she said — McClendon repeatedly questioned why load resources are being excluded from the ancillary services ERCOT is purchasing to guard against emergency conditions.

She said the REPs are unhappy with the grid operator's approach to conservative operations, which includes procuring up to 7.8 GW of operating reserves, after they had committed to and hedged their contracts for the year.

Noting one slide in Jones' report referred to "PUC/ERCOT collaboration," McClendon said it should be changed to "PUC/ERCOT staff collaboration," as stakeholders were not included. She asked that the minutes reflect that ERCOT's 60-point "*Roadmap to Improving Grid Reliability*" was never approved by the board or the Public Utility Commission, though she did concede that many people, including board members, provided input.

McClendon, a former director who rejoined the board after the flurry of resignations in the wake of the February winter storm, has been one of its most vocal members in the months since. She was supported by Oncor's Mark Carpenter, the investor-owned utility segment's representative, when the discussion turned to No. 36 on the roadmap, "ensure the Technical Advisory Committee is comprised of senior-level members from each member organization to promote timely decision-making."

The *30-member TAC*, representing seven different stakeholder segments, works on protocol changes and makes recommendations on ERCOT policies and procedures to the board. Last month, it pushed back on Jones' proposed change during its regular monthly meeting. (See *ERCOT Technical Advisory Committee Briefs: July 28, 2021*.)

"That particular group is a highly functional, technical group. It has broad knowledge of the committees and subcommittees that report to it," Carpenter said. "The makeup seems to be working very well. I think there's quite a bit of concern … there's going to have to be some discussion at some point."

Jones agreed with Carpenter and said his proposal to restructure the TAC is "controversial." As he did before the committee last month, Jones said the state government has lost confidence in ERCOT's stakeholder process following the storm, but he said the committee is "working through that." The TAC has scheduled its *first workshop* for this Wednesday to discuss alternatives.

Texas lawmakers passed several pieces of legislation in responses to the ERCOT's near collapse during the storm. None was more important than *Senate Bill 2*, which replaces the board's market participant representatives with independent directors from outside the market.

A three-person selection committee appointed by the state's political leadership will select the new board members; the first board members aren't expected to be seated until September.

"That's what I want to see improved," Jones said, referring to politicians' lost trust. "I want to see we are reacting to that sentiment so they have trust in TAC that the new board may not have. Changes need to be made to improve the way [committee members] work with the new board, whenever that new board is seated."

McClendon, who sat on the TAC before joining the board, said she "adamantly" disagreed with Jones' perception of politicians' level of confidence in ERCOT stakeholders.

"You're leaping to conclusions when you say they've lost confidence in the stakeholder process," she said. "For everyone you say that has lost confidence, I can give you two [who haven't]. I will need to see that in writing, from whomever you need to get it from."

"Very good," Jones replied.

PUC Chair Peter Lake, who has also chaired board meetings in the absence of a chair, jumped into the conversation. He said SB2 clearly made "substantial changes" to ERCOT's governance with its removal of market participants on the board.

"Leadership is moving forward with that transition process," he said. "While we'll have to defer to the yet-to-be named ERCOT board, rest assured that while the stakeholder process may look different, depending on how the new board approaches it, I am confident there will be a robust stakeholder process going forward, and the new board will work with the membership to identify the best version that we can deliver for Texas."

McClendon did wrangle a commitment from Jones that ERCOT staff would consider including contributions from load-serving entities as they continue to increase operating reserves with ancillary services. Jones said that when load resources are used, it results in a drop in ERCOT's physical responsive capability, which must then be replaced by generation.

"We think this is the most conservative approach in meeting the needs of all Texans," Jones said.

When McClendon continued to contend that ERCOT staff are making the decisions on procuring ancillary services without the board's input, Jones reminded her that staff spent two sessions before the TAC explaining their actions.

But McClendon responded, "It was a directive. It was a one-way conversation. I don't think we necessarily want to get into the politics of how that was approved."

"We want to stay out of [energy emergency] alerts [EEAs]. We want to stay out of emergency conditions," Jones said. "That's our goal."

There, he found agreement.

"We don't want the public to think we can't manage a grid by sending out EEAs or conservation messages," McClendon said. "Load can keep that from happening."

Board Signs off on 2022-2023 Budget

The board agreed with the Finance and Audit Committee's recommendation to approve the 2022-2023 biennial budget and to keep the administrative fee at its current 55.5 cents/MWh rate.

The approval authorizes operating expenses,

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project spending and debt-service obligations of $322.2 million and $287 million for 2022 and 2023, respectively. The committee said the budget will fund additional costs resulting from the February storm and the Texas Legislature's numerous bills addressing the event.

The budget is an increase over the current 2021 budget of $275.2 million, which is currently projected to be off by $35.6 million at year-end. Revenues are projected to come in under $24.1 million and expenses $11.5 million over budget.

ERCOT expects to take a $6.9 million hit from insurance premiums and legal costs stemming from the winter storm, Jones said. Staff's move to a new office space early next year is also forecast to come in $4.7 million over budget.

ERCOT CFO Sean Taylor said staff shared the committee's recommendation to leave the administrative fee untouched, saying the grid operator could recover costs in future years "when market participants have the ability to absorb the increase."

The city of Dallas' Nick Fehrenbach, who chairs the FAC and represents the commercial consumer segment, voted against the measure over previously disclosed concerns that the market's uncertain future design and deficit could put the new board in a position where a fee increase will be necessary. (See "'Strong Upward Pressure' on Budget," *ERCOT Briefs: Week of July 19, 2021*.)

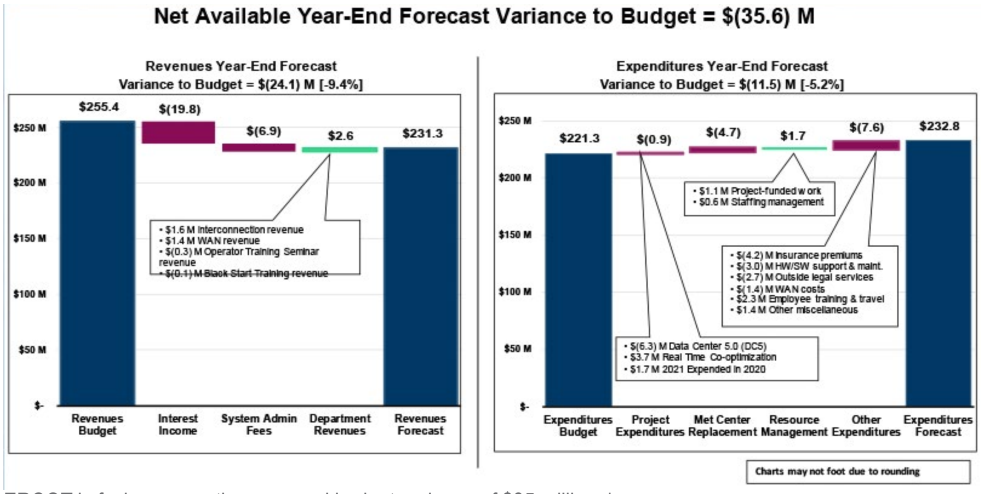
Garland Power & Light's Tom Hancock, who speaks for the municipal segment, also voted against the budget's approval. McClendon abstained.

Passport Program 'Uncoupled'

Staff delivered a final board update on the *Passport Program*, which bundles together several high-profile initiatives but has been thrown off schedule by the work needed to address the winter storm's effects.

The program has been "decoupled" into "manageable pieces," ERCOT's Matt Mereness said, to keep the focus on the energy management system's (EMS) technology upgrade. The upgrade, the first since 2017, is scheduled to be completed in mid-2024; Mereness has previously said the upgrade is "non-negotiable." (See "Passport Pushed Back 18 Months," *ERCOT Technical Advisory Committee Briefs: April 28, 2021*.)

However, staff will need at least 18 months after the EMS project to add real-time co-optimization (RTC) and its $51.6 million price



ERCOT is facing a negative year-end budget variance of $35 million. | *ERCOT*

tag to the ERCOT market. Real-time co-optimization, which clears energy and ancillary services every five minutes in the real-time market, accounts for the biggest chunk of Passport's $85.5 million cost.

"We're on at least a one-year delay," Mereness said. "We'll put [RTC] on the shelf. When it's time to bring it off the shelf, we can do so."

Staff will ask the TAC next month to formally retire the RTC Task Force.

New Wind, Solar Generation Highs

ERCOT has set new instantaneous records for wind and solar generation this summer, Jones told the board. Wind energy reached 23.6 GW at 10:32 p.m. on June 25, while solar peaked at 6.9 GW at 10:30 a.m. July 31.

The grid operator also set a new peak for June when demand hit 70.2 GW during the afternoon on June 23.

Staff have said they have sufficient capacity to meet a projected peak demand of 77.1 GW this summer. That would break the record of 74.8 GW set in August 2019, but demand has topped out at 72.9 GW on July 26 so far this summer.

SCT Directive, 14 Changes Approved

The board approved the latest in a series of directives tied to *Southern Cross Transmission*, a proposed HVDC line in East Texas that would ship more than 2 GW of energy between the Texas grid and Southeastern markets. (See "Members Debate Southern Cross' Bid to be Merchant DC Tie Operator," *ERCOT Technical Advisory Committee Briefs: Feb. 22, 2018*.)

Directive 9 required staff to evaluate whether the project would require any modifications to existing or additional ancillary services. In a *white paper*, staff said *NPRR1034*, approved in February, gives ERCOT authority to establish limits on DC tie transfers and to curtail their schedules when necessary to address the risk of unacceptable frequency deviations. They found there was no need for other changes to accommodate the project.

The board also passed eight Nodal Protocol revision requests (NPRRs), a single change to the Nodal Operating Guide, two modifications each to the Planning Guide (PGRRs) and the resource registration glossary (RRGRRs), and a system-change request (SCR), all previously endorsed by the TAC in June and July:

- *NPRR995*: sets the term "settlement-only energy storage system" (SOESS) and further defines it as transmission-connected or distribution-connected; relocates the settlement-only generator (SOG) term from under resource to standalone as its own unrelated term; and incorporates the relevant SOESS terms into the market information system (MIS) reporting created for SOGs.
- *NPRR1005*: redefines point of interconnection (POI) to refer to any physical location where a generation entity's facilities connect to a transmission service provider's facilities; removes references to load interconnections; introduces the term "point of interconnection bus" (POIB) for the bus in the substation closest to the resource's POI or any electrically equivalent bus in the substation; and changes POI to POIB throughout the protocols, among other revisions.
- *NPRR10*63: requires ERCOT to post dynamic

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rating approval information to the MIS secure area.

- NPRR1073: prevents a market participant from exiting the market to escape uplift charges and then trying to re-enter under a different name.
- NPRR1078: ensures only amounts owed to ERCOT by counterparties through the default uplift process can be collateralized.
- *NPRR1079*: separates ERCOT contingency reserve service, which will come in a future release, from fast frequency reserve project language being added to the 48-hour day-ahead market report requirements.
- *NPRR1083*: prohibits uplift charges to qualified scheduling entities acting as central counterparty clearinghouses in wholesale market transactions or regulated as derivatives clearing organizations as defined by the Commodity Exchange Act.
- *NPRR1086*: aligns the protocols with the PUC's recent order eliminating the market's pricing mechanism link to natural gas prices and adds a provision to ensure a resource, through its qualified scheduling entity, can recover its marginal costs during scarcity pricing situations while the low systemwide offer cap's is in effect.
- *NOGRR210*: clarifies language in the revised POI term and NPRR1005's POIB.
- *PGRR089*: revises the list of data sets posted to the MIS by removing the planning horizon transmission capability methodology and adding long-term system assessment postings, geomagnetic disturbance vulnerability assessments and the monthly generator interconnection status.
- *PGRR091*: gives interconnecting entities 60 days to complete an application for a full interconnection study.
- *RRGRR025*: clarifies language for NPRR1005's defined POIB term by modifying the existing POI term to conform to the generation agreement's conception of the POI as the point of ownership change. The revision also removes the generation agreement's reference in that definition.
- *RRGRR028*: adds transformer manufacturer test reports to the data collection requirements and clarifies the required transformer information.
- *SCR815*: aligns market guides, streamlines processes, increases transparency and tracking, and improves communication among market participants in the MarkeTrak tool used to resolve retail market issues. ■

— Tom Kleckner

ISO-NE News

NEPOOL Markets Committee Briefs: Aug. 10-12, 2021

The NEPOOL Markets Committee devoted all three days of its summer meeting last week to continued discussion of ISO-NE's revised proposal for FERC Order 2222 compliance and removal of the minimum offer price rule (MOPR) from the RTO's capacity market.

| Shutterstock

Order 2222: ISO-NE Answers Questions on EAS Markets Participation

During the July MC meeting, there were several stakeholder questions during the *presentation* on energy and ancillary services (EAS) markets participation, to which ISO-NE wanted to *provide* follow-up answers, including:

- understanding whether a facility can participate in different aggregations, and if multiple parties can take ownership in an aggregated resource; and
- clarifying if a distributed energy resource aggregation (DERA) can participate under multiple models in the energy markets.

The RTO defines a facility as an electricity-consuming or -producing device located in homes and buildings, such as batteries, water heaters, electric vehicle chargers, HVAC systems and rooftop solar. Different capabilities of a facility can participate in different aggregations, ISO-NE said.

A facility's energy withdrawal capability, for example, can be in a different aggregation from its demand reduction or energy injection capabilities as energy withdrawal is measured separately from demand reduction or energy injection. However, only one aggregator can register the energy withdrawal capability of a facility. Similarly, a facility's regulation capability can be in a different aggregation from its demand reduction, energy injection or energy withdrawal capabilities but registered to only one aggregator.

In a change from its July presentation, the RTO said demand reduction and energy injection capabilities at a facility cannot be split among different aggregations. The implication was that the demand reduction capability of houses could be part of a demand response DERA and the energy injection capability could be part of a separate settlement-only DERA. ISO-NE said that was "problematic" because it would not provide the proper financial incentives for the demand response DERA to follow the dispatch instruction.

The demand response resource model avoids that problem by requiring a facility's demand

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reduction and energy injection capabilities to be in the same aggregation.

Each DERA must participate under a single participation model in the energy markets based on its mix of capabilities. A DERA can choose from six energy market participation models: generator asset, binary storage facility (BSF), continuous storage facility (CSF), settlement-only DERA, demand response DERA or demand response resource.

The rules would also prohibit offering separate portions of a DERA into individual participation models because it acts as a single resource in the market, represented by a single set of requirements and offer parameters. All participation models include a specific set of requirements and offer parameters. A DERA must choose the model that best represents its combined capabilities.

However, a DERA participating under the demand response DERA, settlement-only DERA or demand response resource models in energy markets may simultaneously use the alternative technology regulation resource (ATRR) model to participate in the regulation market. DERAs that join under the generator asset, BSF or CSF models do not need to use the ATRR model to participate in the regulation market because they already include participation.

MOPR: Framing the Debate

Mark Spencer of LS Power gave a *presentation* making the case that eliminating the MOPR without accompanying changes to address supply-side buyer power may not yield a just and reasonable rate. The Federal Power Act, FERC precedents and the ISO-NE tariff explicitly require regulators "to balance seller and buyer interests," he said.

Spencer added that supplier-side mitigation reforms are needed to prevent the exercise of supplier market power for financial gain. In the current framework of the dynamic delist bid threshold (DDBT), all market participants, regardless of portfolio size or pro-rata quantity, that wish to delist must submit a cost workbook months in advance and lock in their bids. By removing the MOPR, mitigation will only be applied to existing merchant resources, not existing subsidized resources or new entry. The DDBT is calculated on the preceding auction clearing price, which is presumed to be a competitive result, and it ignores the administrative barriers that prevent market participants from submitting competitive offers

It also does not account for the effects of the MOPR elimination, which will likely result in an uncompetitive auction clearing price.

Spencer said potential solutions include:

- a DDBT based on a simulated competitive result;
- applying a net benefits test to determine which market participants are capable of wielding market power and allowing the others to submit competitive bids; and
- examining the need for a sealed bid auction framework to address concerns of start-of-round market power. ■

— Jason York

Maine Judge Vacates Public Land Lease for NECEC Tx Line

Continued from page 1

Environmental groups that oppose the transmission corridor argued in court that construction of the transmission line in the Upper Kennebec Region is destructive to the largest undeveloped forest east of the Mississippi River.

Many of the people involved in the opposition against the project work as river guides on the Moose and Upper Kennebec Rivers, which cross the rugged landscape threatened by different kinds of development over the last few years.

A large swath of trees will be cleared for the project, posing a barrier to wildlife crossings and affecting forestry operations in the area, Tom Saviello, a volunteer with the advocacy group No CMP Corridor, said in a phone interview with *RTO Insider*.

The line would also cut between two ponds that hold 95% of the remaining native trout. Water runoff from the transmission construction could warm the water in the ponds, changing the ecosystem for the trout, Saviello said.

Thorn Dickinson, head of NECEC Transmission, issued a statement saying the company is "reviewing the Superior Court's decision to determine our next steps on the matter."

CMP currently holds the lease of public land but is transferring it to NECEC Transmission. Both companies are owned by Avangrid.

The $1 billion NECEC project is intended largely for the benefit of Massachusetts residents, who are paying for the construction of the 1-mile, 300-foot-wide corridor.

November Vote

The NECEC project faces an even greater risk in November, when Maine residents vote on whether to approve three new potential requirements for transmission line construction in the state that would effectively halt the hydroelectric energy transmission line.

The Maine legislature would have to approve the construction of any high-impact electric transmission lines under the potential requirements by a two-thirds majority, according to a report by independent research firm ClearView Energy Partners. Second, the legislature would have to approve any use of public lands for transmission lines and related facilities. The state would also entirely prohibit the construction of high-impact electric transmission lines in the Upper Kennebec Region.

The mandates would be retroactive to 2014, including the NECEC transmission line.

CMP can appeal the ruling that vacates the lease, but it is not likely a higher court would rule differently if the state constitution requires two-thirds approval from the legislature.

The BPL could also issue a determination that the lease does not reduce or substantially alter the public land in question, but opponents could still challenge the lease and the determination, the report said.

CMP will "have no choice but to negotiate the terms of this public lease in an open and transparent way," Saviello said. ■

ISO-NE News

GlobalFoundries' Bid for Vt. Utility Status Could Trip up 100% Renewable Proposal

By Jennifer Delony

Semiconductor manufacturer GlobalFoundries, which operates a facility in Essex, Vt., seen here, is seeking state approval to be a self-managed utility. | *GlobalFoundries*

Semiconductor manufacturer GlobalFoundries' plan to become a self-managed utility in Vermont has raised concerns about the future of a proposed 100% renewable energy standard (RES) for the state.

During a public comment session Aug. 10, Ed McNamara, director of the Regulated Utility Planning Division at the Vermont Department of Public Service (DPS), avoided answering questions about how the company's plan might affect the RES straw proposal.

The manufacturer, which has a facility in Essex, Vt., is responsible for about 8% of the state's electricity load. It claims that global semiconductor market conditions are such that if the company does not reduce its energy costs, it will need to move out of the state.

GlobalFoundries' petition for utility status is a hiccup in an already tricky situation that has the DPS updating the state's comprehensive energy plan and trying to align it with the pending state climate action plan. Drafts of both plans are due this fall.

In July, the Vermont Climate Council's Cross-sector Mitigation Subcommittee recommended that the full council increase the state's existing RES in the final climate action plan from 75% by 2032 to 100%, with no proposed target year. The subcommittee's members, which include McNamara and Green Mountain Power's (GMP) chief legal officer, Liz Miller, cooperated with DPS staff on the meeting last week to gather input on the potential design of a 100% RES.

But the officials from both camps were unable to answer questions from attendees on how GlobalFoundries' plan would fit into the new RES. That's because McNamara and another representative of GMP are witnesses in the case for GlobalFoundries' petition filed in March with the Vermont Public Utility Commission (PUC) (*21-1107-PET*).

In its petition, GlobalFoundries asked for approval to purchase its electricity through the ISO-NE market instead of being a GMP customer.

Central to stakeholder concerns about the petition is the company's request for exemption from compliance with Vermont's existing RES because it would not distribute or sell electricity. Vermont's RES requires its electric utilities to procure a percentage of their retail sales from renewables.

If the PUC exempts GlobalFoundries from RES compliance, the power it procures through ISO-NE "potentially could be from the general mix, which as we know, contains lots of fossil fuel in the form of natural gas," Chase Whiting, litigator for the Conservation Law Foundation (CLF), said during the public meeting.

Given that DPS and GMP generally support the petition, Whiting said, and they are considering a possibility in which 8% of the state's electricity load is not subject to a 100% RES, those positions "seem a little bit in conflict with one another."

GMP's support, according to Miller, is based on GlobalFoundries' commitment in its petition to meeting the state's greenhouse gas (GHG) reduction goals.

But a commitment isn't enough, said Ben Walsh, climate and energy program manager at the Vermont Public Interest Research Group.

"They should bind themselves to the same requirements that every other electricity user in the state has and be part of the renewable energy standard going forward," he said.

If the company continues to seek an RES waiver, he added, the DPS and the council should not be leading the conversation on how to design a new standard.

McNamara acknowledged that there are outstanding issues related to GlobalFoundries' petition and the RES proposal, but he said he had concerns about CLF questioning him outside of the litigation.

Impact on Vermont

Altering GlobalFoundries' position as an energy customer of GMP would not be without significant consequences for the state, according to witness testimony.

If the PUC approves the petition and waives RES compliance, Vermont's GHG emissions "likely would increase," Asa Hopkins, vice president at Synapse Energy Economics, said in testimony on behalf of CLF.

The company would not be obligated to purchase renewable energy in the market, and "purchasing and retiring RECs beyond what is strictly required would be contrary to GlobalFoundries' focus on the lowest-cost power supply," Hopkins said.

State emissions would increase by 88,000 metric tons in 2027, rising to almost 100,000 metric tons in 2032 and each year after, he said, adding that the social cost of those emissions would be $10 million in 2032 and each year after. Furthermore, the company's emissions increase would equate to 2.3% of Vermont's total emissions in 2030.

"To meet the [GHG emission-reduction] requirements of the 2020 Global Warming Solutions Act, Vermonters would have to take substantial additional other actions in order to compensate for GlobalFoundries' lower contributions," Hopkins said.

If the petition is denied and the company moves out of Vermont, the economic consequences would be "unprecedented," Arthur Woolf, of Arthur Woolf Economic Consulting, said in testimony on behalf of GlobalFoundries.

With 2,200 in-state employees, GlobalFoundries is the largest for-profit employer in Vermont, and it pays $2.6 million in property taxes in Chittenden County. In addition, GlobalFoundries exports $1.3 billion in products from its Vermont facility, an economic activity that Wolf said brings additional value through "intellectual property, education and workforce development potential." ■

MISO Targets March Approval for Long-term Tx Projects

By Amanda Durish Cook

MISO acknowledged last week that a December approval of its first long-range transmission projects is out of reach and must wait until early spring.

The grid operator originally planned to submit the first collection of long-range projects with the 2021 MISO Transmission Expansion Plan (MTEP 21) in December. Staff planners had warned in recent weeks that meeting the pre-Christmas approval was increasingly unrealistic.

Now, MISO is targeting board approval of the long-range projects in March.

"We recognize that to have it before the board for approval by December is increasingly unlikely," Aubrey Johnson, executive director of system planning, told stakeholders during a Planning Advisory Committee teleconference Wednesday.

MISO will still consider any long-range projects approved in March as part of MTEP 21.

"I want to put that out there to allay any concerns with stakeholders about an aggressive timetable," Johnson said.

"We're making progress," Senior Manager of Transmission Planning Coordination Jarred Miland assured stakeholders. He said staff will soon unveil some potential long-range transmission solutions.

Stakeholders voiced concern that MISO was postponing the projects' approval and still categorizing them under MTEP 21.

"There nothing that says every single project has to go through the board of directors in December," Miland said. "It's just that's the way we've done it. We can do this as an addendum."

Jeff Webb, the RTO's senior director of transmission planning, agreed that "there's nothing keeping" MISO from bringing some project recommendations to the board on a deferred basis.

"We have had occasions for this in the past. We don't see any concern in the tariff about staff completing an analysis and submitting a project when they finish," Webb said. "Now, the board is not too keen on the board approving projects in many months, so we keep it on an annual routine."

WEC Energy Group's Chris Plante said it was unclear how the MTEP's bottom-up planning approach will mesh with the long-range plan's top-down planning. MISO typically studies MTEP project needs after transmission owners propose them. In the long-range plan, staff will study and prescribe system needs.

MISO said it already has been fielding project ideas from stakeholders to resolve known issues, although the RTO hasn't formally opened a proposal window.

Staff have stressed that the long-range plan is contemplating regional transmission solutions, not seeking to make interconnections easier for new generation. MISO planners have repeatedly said their concerns lie in the transmission system's reliability over the next two decades.

"Our focus is to make sure we have a reliable system to serve a future load with reliability targets," Senior Economic Planning Engineer Ranjit Amgai said during a July 30 workshop teleconference.

MTEP 21

MISO will recommend 367 new projects, valued at $3.4 billion under MTEP 21, for board approval in December. This year's package is lower than MTEP 20's final $4.05 billion spend on 493 projects.

This year's MTEP contains 49 generator interconnection projects at $319 million, 61 baseline reliability projects at $462 million, and 257 "other" projects at $2.65 billion. The "other" category is reserved for projects that address load growth, reliability needs, and age and condition-related fixes.

MTEP 21's most expensive project is the $196 million rebuild of the 115-kV Golden Meadow-to-Barataria line near New Orleans. The line will be rebuilt to a 230-kV rating after 2020's Hurricane Zeta damaged it.

The Planning Advisory Committee will vote on whether to recommend the MTEP report during its September meeting. Regardless of the voting outcome, MTEP 21 will advance to the board's System Planning Committee for final consideration.

MISO News

MISO is currently managing 2,282 active MTEP transmission projects representing $12.45 billion, dating back to the 2008 MTEP cycle. The grid operator *expects* most of those projects to come online over the next three years.

Transmission owners last week also asked for a simplified database to report the status of approved MTEP projects.

Speaking during the Planning Subcommittee's meeting Aug. 10, ITC Transmission's Cynthia Crane encouraged MISO to "create a new platform with input from all stakeholders, not just the transmission owners."

She said MISO currently maintains too many status options to choose from, causing TOs to use different terms to describe identical project stages. She said that under the current process, TOs unnecessarily describe their projects multiple times.

Crane asked for a more standard set of status categories and clearer MISO expectations for when cost updates are required.

Staff are also considering whether it should create separate forms and processes that allow retiring generators to convert to synchronous condensers under MISO's non-transmission alternatives consideration.

"It's probably a very limited application," MISO's Jeanna Furnish said. ■

La. and Miss. Join MISO, TOs in Opposing Cost Sharing at 100 kV

By Amanda Durish Cook

Louisiana and Mississippi regulators have joined FERC, MISO and the RTO's transmission owners in asking an appellate court to reject LS Power's campaign for regional cost sharing of transmission projects as low as 100 kV.

MISO last year overhauled its cost allocation procedures, lowering the voltage threshold for market efficiency projects that are regionally cost shared from 345 kV to 230 kV, adding two new benefit metrics and eliminating a 20% footprint-wide postage stamp allocation. (See *MISO Cost Allocation Plan Wins OK on 3rd Round*.)

FERC rejected LS Power's rehearing requests and complaint that a further reduction to 100 kV was necessary, concluding that the 230-kV threshold would spur more economic projects and sufficiently expand the number eligible for competition. (See *FERC Spurns LS Power's Voltage Threshold Argument*.) LS Power soon took its argument to the D.C. Circuit Court of Appeals, asking it to overturn FERC's ruling (20-1465).

The Louisiana and Mississippi public service commissions filed a joint brief Aug. 9 in opposition to LS Power's petition, the same day as a joint brief by MISO and its TOs. FERC defended its ruling in a *brief* July 26.

"The 230-kV threshold enjoyed broad stakeholder support after a long, comprehensive stakeholder process, represented a compromise supported by a majority of [MISO] stakeholders and was supported by substantial evidence. The courts and FERC have acknowledged the importance of the stakeholder process; unanimity is not required," the Louisiana and Mississippi PSCs said.

| LS Power

The two said LS Power was attempting to pre-empt "years of extensive negotiations" between MISO, stakeholders, regulators, load-serving entities, generation owners and independent transmission owners.

"LS Power participated extensively but was simply dissatisfied with the results. … FERC looks for general support for the broad outline of a cost allocation proposal, not at individual preferences within the stakeholder process," the PSCs said. "Unilateral, non-vetted changes to the [MISO] tariff filing would have disrupted the compromise reached among a majority of stakeholders."

MISO and its TOs agreed with FERC that LS Power lacked standing to challenge the ruling and insisted the commission had properly followed precedent in approving MISO's proposal.

"Petitioners do not dispute that the 230-kV threshold is an improvement over the then-effective 345-kV threshold, but blame FERC for taking a 'half-measure' by not mandating a lower threshold," they said. "Having found evidence to support the 230-kV threshold (as part of a package of improvements) as just and reasonable, FERC correctly rejected petitioners' alternative voltage threshold. … Whether there is evidence to support a finding that a lower threshold may also be just and reasonable is irrelevant." Louisiana and Mississippi regulators said MISO's cost allocation plan followed Order 1000's directive that costs assigned are roughly commensurate with benefits received.

In MISO, projects between 100 and 230 kV that don't fit into any other of MISO's project category are classified as economic "other" projects and cost allocated only to the transmission pricing zone in which they are located.

LS Power argued that FERC's refusal to order a lower threshold ran counter to 2018's *Old Dominion Electric Cooperative v. FERC* (*17-1040*), in which the D.C. Circuit ruled FERC erred when it prohibited cost sharing for a class of high-voltage projects that demonstrated significant regional benefits.

But the state commissions said that LS Power failed to show that projects between 100 and 230 kV consistently produce broad, regional benefits. They also said LS Power was misguided in its decision to invoke Northern Indiana Public Service Co.'s 2013 complaint over the PJM-MISO seam, which resulted in FERC eliminating a cost minimum and lowering the voltage threshold for MISO-PJM interregional projects to 100 kV. The states said the 100-kV threshold ordered in that case was not meant to apply to all circumstances.

"The [NIPSCO] orders dealt with circumstances and long-standing issues specific to the [MISO]-PJM seam and interregional projects. … Those orders offer no precedent here," they said. ■

MISO News

MISO Stakeholders: Separate Allocations Isolate Regions

By Amanda Durish Cook

MISO Midwest comprises the North and Central regions with a constrained link to and from MISO South. | *MISO*

MISO stakeholders made it clear last week that a separate cost-allocation design for the South subregion's long-range transmission projects will preserve the footprint's most notorious constraint.

Several said during a Thursday conference call on cost allocation that maintaining one set of cost-sharing principles for MISO Midwest and another for MISO South would throw a wrench into any plans to expand the transfer capability between subregions.

WEC Energy Group's Chris Plante said disparate allocations would further "vulcanize" the Midwest from the South and make a healthier transmission link between the regions even more difficult to get built.

"I disagree with having different cost allocations between the North and South," Lauren Azar, attorney for the Sustainable FERC Project, said. "I think just from a public policy perspective, we should be strengthening the ties between North and South. We need to bolster the resilience of MISO South."

MISO has a 1,000-MW contract path bridging its Midwest and South subregions. Seven years ago, MISO and SPP reached an agreement setting a 3,000-MW limit on subregional transfers in the north-to-south direction and a 2,500-MW limit in the other direction. MISO sometimes exceeds those limits during emergency conditions but nearly always limits exceedances to the 30-minute grace period.

Staff in late July proposed using the 2011 Multi-Value Projects' (MVP) allocation for the Midwest, which relies on a 100% uniform, "postage stamp" rate for load. The grid operator said it would wait to propose an alternative long-range cost allocation for MISO South. (See *MISO Dusts off MVP Cost Allocation for Long-range Tx Plan*.)

John Wolfram, a consultant representing transmission owner Hoosier Energy, said he didn't think FERC would endorse bifurcated allocation methods for Midwest versus South.

"I think it will deter or serve as a barrier to increasing the transfer capability between North and South, which, frankly, should be a huge component" of the long-range transmission plan, he said.

"MISO as a whole will be much better off if it has one approach," Clean Grid Alliance's Natalie McIntire said in agreement. "I also think we're much more likely to get approval from FERC if we have one allocation."

The Coalition of Midwest Power Producers' Travis Stewart said FERC has a history of rejecting filings that propose charging different rates for the same product. He said a case in point was MISO's futile 2016 attempt to conduct separate three-year forward capacity auctions using a sloped demand curve only for a footprint's deregulated areas.

Some stakeholders asked MISO to provide an example of how it would split costs using two types of cost allocation on projects that touch both the Midwest and South.

Michigan Public Service Commission Chair Dan Scripps said MISO's MVP allocation "may very well be the devil you know" and pointed out that it already enjoys FERC approval.

MISO plans to file a cost allocation for long-term transmission projects sometime in late fall. Staff said a fall deadline will allow time for FERC to issue a decision before the first long-term transmission proposals are put before the MISO Board of Directors in March. (See related story, *MISO Targets March Approval for Long-term Tx Projects*, p.17.)

Entergy, Southern Regulators Offer Proposal

Entergy and MISO South regulators revealed their preference for long-term transmission cost allocation during the meeting. MISO Midwest uses an energy-based postage stamp allocation, but stakeholders requested a demand-based allocation with one of three criteria:

- an allocation to a regulatory body's jurisdiction when a candidate project fulfills a policy need;
- allocation of a project candidate with "quantified economic benefits" to benefiting cost allocation zones; or
- a two-step allocation where project costs are first assigned to cost allocation zones that are found to have economic benefits; remaining costs are then dispersed to pricing zones that avoid developing reliability

MISO News

projects.

MISO South regulators and Entergy have also asked for a 1.25:1 benefit-to-cost ratio and 230-kV minimum voltage thresholds, greater than MISO's 1:1 benefits ratio and 100-kV minimum. They both agree on a $20 million project cost threshold.

Some stakeholders pointed out that consistently high-load customers would benefit more from a demand-based allocation than an energy usage-based allocation.

Southern Renewable Energy Association Executive Director Simon Mahan said the MISO South proposal would allow Louisiana, with its heavy and constant industrial energy use, to "make out like a bandit."

MISO is expected to adjust its allocation proposal based on the stakeholders' discussion. The grid operator will hold another workshop on its long-range plan Aug. 27. ■

Shorter Interconnection Queue Coming, MISO Says

By Amanda Durish Cook

MISO will submit proposal to FERC in the fourth-quarter to slim its generator interconnection queue timeline from about 505 days to a single year.

The RTO wants the timeline of an interconnection customer entering a generation project into the definitive planning phase (DPP) to signing an interconnection agreement to be about a year. It said it will achieve the reduction by cutting the days allotted for generator interconnection agreement (GIA) negotiations and study, performing some study aspects simultaneously. (See "Queue Timeline Cutbacks Still in the Works," *MISO Winds down MTEP 20 Planning, Focuses on 2021*.)

At a Planning Advisory Committee meeting Wednesday, interconnection study engineer Miles Larson said MISO will cut about 40 days from the current 140-day first DPP but add about 25 days to the second, 80-day DPP. Larson explained that the second DPP could use the extra days because it contains more intense study, including a stability analysis and short-circuit analysis.

For the current, 135-day third DPP, an interconnection customer will be met with a fork in the road. They will have a choice to either:

- spend about 60 days in the stage if it doesn't need to know the results of its network upgrade facilities study before proceeding to GIA negotiations; or
- devote about 150 days to the phase if it needs a network upgrade facilities study report before proceeding to the GIA. This route would result in an approximate 463-day total queue timeline.

Construction of DTE Energy's Meridian Wind Park | *DTE Energy*

GIA negotiations themselves will be slimmed from about 150 days to about 108.

Larson said if MISO can usher generators through interconnection studies closer to a single calendar year, it will rely on better planning assumptions, as the Transmission Expansion Plan also functions on a yearly basis. He said the RTO's goal is to "provide more information to stakeholders earlier in the process to give everyone more time to review models, plan for mitigations and review results."

Stakeholders have been pessimistic that MISO can achieve its single-year goal because it's dogged by notoriously time-consuming affected-system analyses with its neighbors.

"MISO continues to have discussions with [affected-system] teams on expectations and potential process improvements and alignments efforts," Larson said. "We're optimistic that many of these developments … will allow us to meet overall deadlines of the study schedule."

He said if the changes don't meaningfully shorten time spent in the queue, MISO will "entertain larger process changes," including reworking local planning criteria studies and hiring consultants "where and when needed."

"We're going to continue to look at process improvements. We don't have concrete examples today," Larson said. He added that if delays persist, MISO will bring additional proposals to the stakeholder-led Interconnection Process Working Group.

"Compared to what we see in other parts of the country, MISO is really a leader in its willingness to make improvements to its interconnection queue," Clean Grid Alliance's Natalie McIntire said. ■

NYISO Unveils Draft BSM Study

By Michael Kuser

NYISO last week unveiled a draft study **plan** on ways to model 10-year capacity supply and demand curves and identify the resulting market outcomes in order to advance the ISO's effort to revise its buyer-side mitigation (BSM) rules.

The ISO on Aug. 9 presented a proposal to exempt most new solar, wind, storage and demand response installed capacity (ICAP) resources from BSM evaluation. (See *NYISO Proposes Sweeping BSM Exemptions*.)

"We need to look at the proposed changes as an input and say ultimately, 'How is that going to affect the competitiveness of the capacity market at a high level, and will there still be signals for efficient development of resources that are needed to maintain reliability?'" Paul Hibbard of Analysis Group, which developed the plan, told the ICAP Working Group.

New York's Climate Leadership and Community Protection Act (CLCPA) requires the state to procure large amounts of renewable energy resources to get to zero-emission electricity by 2040. The ISO aims to integrate the new resources into its capacity market while maintaining reliability and reasonable rates for all resources.

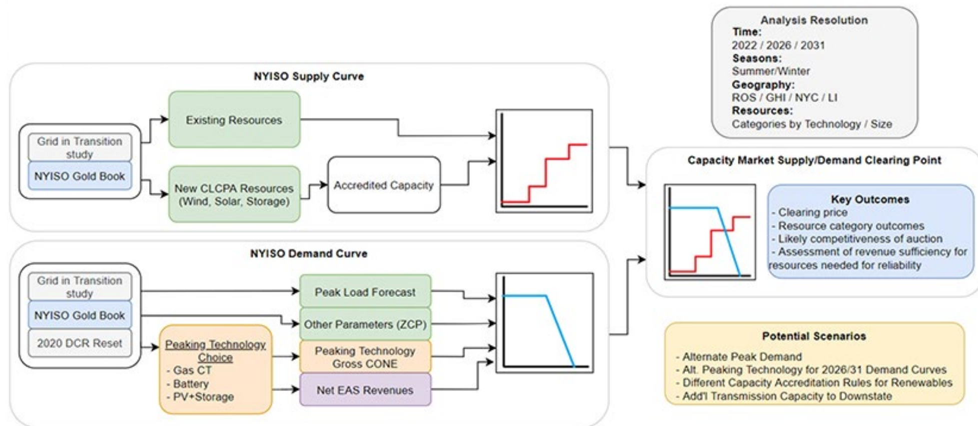
Limited Aims

The ISO wants to maintain the current mitigation regime, including the competitive entry exemption, the self-supply exemption and the supply-side mitigation construct, which with modifications can protect the market against the exercise of buyer-side market power.

Hibbard tried to dissuade stakeholders from looking for long-term conclusions in the current BSM study, which will rely on Analysis Group's 2020 white *paper* on demand curve reset values, publicly available NYISO data and The Brattle Group's Grid in Transition *study* from last year.

It would be a "fool's errand" to try to imagine the shape of wholesale markets 15 years from now, Hibbard said, so the study will attempt to identify the potential impacts of BSM market rule changes that happen now and determine how to manage the capacity market in a sustainable way over the next decade.

That approach allows planners to anticipate



Analysis Group methodology on a study to to model possible capacity market outcomes resulting from revisions to NYISO's buyer-side mitigation rules. | *Analysis Group*

which existing and emerging resources will be important to both fulfilling CLCPA requirements and maintaining reliability, he said.

NYISO staff will return to the ICAP Working Group on Aug. 30 to discuss with stakeholders the related PJM minimum offer price rule (MOPR) filing, which proposed tariff changes to comply with FERC's controversial 2019 order requiring expansion of the MOPR to new state-subsidized resources. Stakeholders said some of the arguments supporting the PJM filing sound as if mitigation of public policy resources is making the capacity market unsustainable over the long term regardless of what happens with capacity accreditation. They said that while BSM may not strongly affect prices, it still can cause customers to buy more capacity than they need, which indirectly affects prices.

Analysis Group will present its BSM study findings to NYISO stakeholders on Sept. 9 and issue a final report soon thereafter.

Accreditation Matters

NYISO also presented a straw *proposal* for capacity accreditation that features six elements on modeling, criteria, frequency, resources, locations and marginality — that is, whether resources should be valued at their marginal or average incremental reliability value.

NYISO believes that establishing the six elements in the broader BSM proposal will be important to demonstrating how reforming BSM will continue to result in just and reasonable ICAP market outcomes, said Zach Smith, the ISO's manager of capacity market design.

The ISO thinks that a suitable capacity accreditation framework is important to justifying large changes to buyer-side mitigation and MOPR rules by "helping us demonstrate that the capacity market will remain a competitive marketplace and support the necessary resource mix required to help keep the lights on in New York," said Michael DeSocio, NYISO director of market design.

NYISO may need to further evaluate an internal "laundry list" of items, Smith said. After the BSM proposal has been approved by stakeholders, the ISO will focus on developing further implementation details for completing a capacity accreditation study.

Determining the final values will take a while, because "to run these studies is not trivial," DeSocio said. "What we're focused on right here, and as part of the BSM work, is to get agreement on the framework."

The ISO's Market Monitor, Potomac Economics, presented a conceptual *framework* and design principles for capacity accreditation, noting that "current rules are inadequate for compensating new resource types and several old types in accordance with their actual reliability value."

At the Aug. 30 ICAP meeting, consultancy E3 will provide examples and technical information on capacity accreditation. The ISO will review tariff changes related to both BSM and capacity accreditation at the Sept. 9 meeting. ■

NYISO News

NYISO Stakeholders OK Tariff Changes for Right of First Refusal

By Michael Kuser

The NYISO Business Issues Committee on Wednesday recommended that the Management Committee approve tariff *revisions* to allow transmission owners to exercise a right of first refusal (ROFR) to build, own and recover the costs of upgrades to their transmission facilities in the ISO's public policy transmission planning process.

Under the proposed changes, TOs could exercise their ROFR even if the upgrades are part of another developer's project selected by the ISO for cost allocation.

The BIC voted 64.91% to advance the measure to the MC, which will consider whether to recommend that the Board of Directors approve the proposal and facilitate an anticipated September filing with FERC under Section 205 of the Federal Power Act. The ISO indicated that such a filing would request a decision within 60 days after filing.

The proposal is intended to apply to the current Long Island offshore wind export public policy transmission need, said Yachi Lin, NYISO senior manager for transmission planning. The filing is anticipated to be prior to an initial draft of a viability and sufficiency assessment of the need.

FERC in April confirmed that New York TOs have a federal ROFR under the ISO's tariff and Order 1000 for upgrades to their transmission facilities, but it declined NYISO's request for clarification that a TO exercising such upgrade rights should be treated as the developer (*EL20-65*). (See *FERC Confirms NYTOs' Right of First Refusal*.)

The commission left open the question as to whether a new transmission facility proposal in another developer's Order 1000 transmission solution requires the agreement of the TO that owns the existing transmission facility, a state regulatory proceeding or a court order authorizing the decommissioning.

The proposal is principally aimed at developing a mechanism for TOs to exercise the ROFR in NYISO's public policy transmission planning process, Lin said, but it also would enhance the information used in the evaluation and selection phase of the process.

Assessing Risk

Several stakeholders asked at what point would a TO know a cost estimate for the upgrades. Another participant asked who would bear the consequences should a transmission upgrade come in late and cause another portion of the project being developed to be delayed, which would be especially significant in the event that the developer has proposed a cost cap.

The ISO has several well defined stages in the planning process, from defining a need to requesting project proposals, through to evaluation and selection, Lin said.

"There are 10 categories of metrics for evaluation and selection, and risk is one of them, so if there is any risk to project completion, it would certainly be best if developers understand their risk and then outline the mitigation measures in their proposal," Lin said.

Cost allocation would depend on the specifics of the relevant contract; on whether a developer proposed a hard cost cap for its own capital costs and included that in the contingency; or if the developer negotiated a soft cap that included cost-sharing with ratepayers, said Carl Patka, NYISO assistant general counsel.

"If the developer wants to argue that, 'well these are circumstances beyond my control completely, and I should be released from the obligation of my hard cap or my soft cap,' they can make an argument, but I can't predict for you today how that would come out at FERC," Patka said.

Implementation Details

The current tariff provisions call for NYISO to enter into a development agreement with the selected developer, whether or not it is a TO, which under the proposed revisions is referred to as the "designated entity," said Brian Hodgdon, NYISO senior attorney.

"The NYISO is treating the developer and TOs that exercise their right of first refusal comparably in regard to the development agreement," Hodgdon said. "Whoever will be developing a selected public policy transmission project or a portion of it will have to enter into a development agreement now, and as we propose in the future, we would just be using the term 'designated entity.'" ■

Stakeholders Endorse but Question PJM's Load Model

By Michael Yoder

PJM stakeholders last week unanimously endorsed the 2021 reserve requirement study (RRS) but requested the RTO conduct further analysis on the impacts of extreme weather conditions.

Patricio Rocha Garrido, of PJM's resource adequacy department, *presented* the results of the RTO's load model selection process at the Planning Committee's meeting Aug. 10. The RTO analyzed 120 load model candidates for the 2025/26 delivery year RRS, based on the *2021 PJM Load Forecast Report* released in January. (See "Load Model Selection," *PJM PC/TEAC Briefs: July 13, 2021*.)

PJM recommended using a 13-year load model utilizing data from 2001 to 2013, moving the time frame back one year from that in the RSS approved for 2020.

Rocha Garrido said the load model candidates were compared to PJM's "coincident peak 1" (CP1) distribution analysis, which represents the highest load expected for the forecast year by using two separate approaches. The model selected in 2020, which used data from 2002 to 2014, was not one of the top candidates this year because of a new CP1 distribution analysis, he said.

The 2021 curve had higher loads and was a "little bit more conservative" compared to the 2020 RRS, Rocha Garrido said. PJM used a 10-year load model (2003-2012) for several years in a row before switching to a 13-year model in 2020.

The load model selection must be conducted because the coincident peak distributions from the PJM load forecast cannot be used directly in the PRISM modeling software, which is the RTO's primary modeling tool used for conducting resource adequacy studies.

PJM also recommended switching the peak week for the MISO, NYISO, Tennessee Valley Authority and VACAR regions, known collectively as the "world" in the analysis, to a different week in July so that it doesn't coincide with its own peak. Rocha Garrido said PJM and the world have peaked on the same day nine times, the last coming on July 19, 2019.

"In PRISM, if you have the two regions peaking on the same week, that's equivalent to peaking on the same day," Rocha Garrido said.

Stakeholder Questions

Paul Sotkiewicz of E-Cubed Policy Associates asked if it would be possible for PJM to conduct similar analysis in the Multi-Area Reliability Simulation (MARS) program, which is able to be "more granular" in data than PRISM.

Rocha Garrido said PJM conducted an overall analysis several years ago of capacity benefit results using MARS, simulating several historical years. He said the resulting analysis in MARS showed to be less valuable in formulating the load model candidates, so PJM decided to continue using PRISM.

Sotkiewicz said that in light of the U.N.'s recent *report* that stressed that global climate change's effects are already happening, PJM should consider re-examining its modeling methods. (See *Too Late to Stop Climate Change, UN Report Says*.)

He pointed to recent events in California, where the state was depending on the ability to import power from its neighbors to cover shortages, but the exporting states were having their own energy issues with high peaks.

A similar scenario could happen in the future on PJM's borders, Sotkiewicz said, including sharing events with NYISO and ISO-NE to the north, MISO to the west and Southern states. He said he didn't want to cause panic among stakeholders or suggest PJM's proposed RSS was incorrect, but he asked if there was enough diversity in the modeling to account for regions all peaking at the same time.

"Maybe this is an opportunity for us to think very seriously about this before it becomes a major problem like it is out west," Sotkiewicz said.

Rocha Garrido said he agreed with Sotkiewicz's concerns and that PJM has looked at potential solutions. He said one of the issues is that PRISM doesn't have the capability to model each of PJM's neighbors separately and data must be inserted as a "monolithic" region that doesn't capture the diversity of the regions.

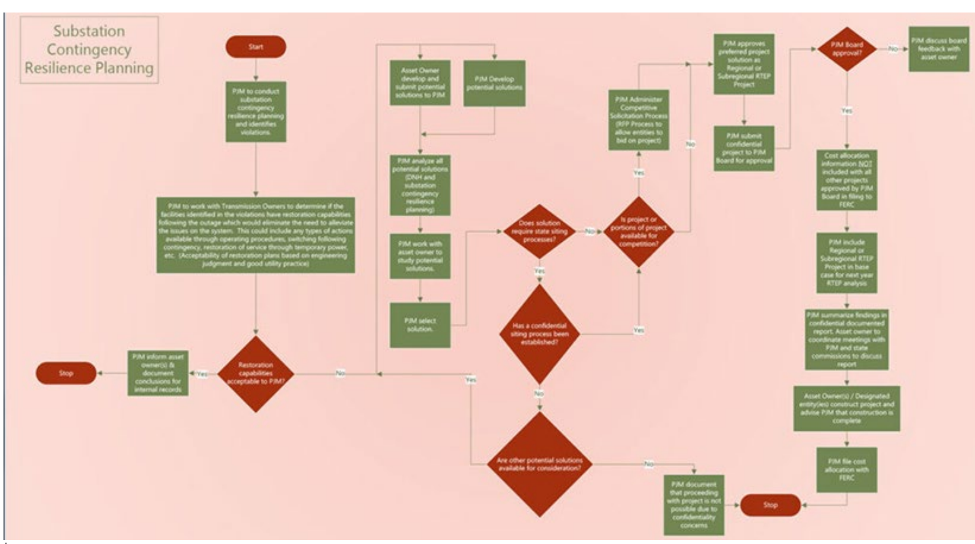
Calpine's David "Scarp" Scarpignato said he has consistently raised the peaking issue and would like to see the RTO and stakeholders come up with a solution.

In 2018, stakeholders hotly debated PJM's proposed *revisions* to adjust the methodology for developing the capacity model for winter peak weeks, expressing concern about how the modifications might affect capacity procurement. (See "Adequacy Analysis Approved Despite Concerns," *PJM MRC/MC Briefs: June 21, 2018*.)

Scarp also said having the historical peak load coinciding with the world nine times in the last 22 years is "pretty significant" and an issue that shouldn't be ignored. He suggested PJM come up with a way of capturing the idea without "making it binary."

"We can't simply say that our modeling will assume that PJM and the world don't peak in the same week, because that doesn't make sense," Scarp said. "We know from empirical data that it does peak in the same weeks."

PJM officials agreed to continue discussions at the Resource Adequacy Analysis Subcommittee. ■



| PJM

PJM News

Tx Upgrades for PJM OSW, Renewables Could Cost $3.2 Billion

Continued from page 1

a starting point and baseline analysis that "holistically" looks at the integration of offshore wind throughout the region. While the study identified costs and the location of upgrades, it does not identify the ratepayers responsible for the costs of upgrades.

"This is not any indication of cost allocation," Bernstein said.

Background

PJM and interested state agencies began meeting in October 2020 in an effort independent from the normal stakeholder process to consider offshore wind public policy needs, Bernstein said. The effort also looked at factoring in all PJM state RPS requirements in the study, even those located far away from the coast.

Preliminary results of the study were presented to stakeholders at the April TEAC meeting. (See "Offshore Transmission Study Update," *PJM PC/TEAC Briefs: April 6, 2021*.)

PJM estimates that reaching state RPS goals will require 74.2 GW of new renewable energy by 2035, including 14.2 GW of offshore wind, 14.5 GW of onshore wind and 45.5 GW of solar. The states' current RPSes also call for nearly 7.2 GW of energy storage by 2035.

Bernstein said the study was meant to be advisory, providing information to states as they move forward on renewable integration and offshore wind policies. It will be up to individual states to determine how to use the information and whether they want PJM to conduct further analysis in a second phase of the study, he said. A final report is expected by the end of the year.

Nothing in the study prevents offshore wind projects from integrating into the system through PJM's normal generation interconnection queue, Bernstein said.

Phase 1 of the study only looked at the onshore impact from offshore wind, omitting considerations of the cost of building offshore or mesh grid networks to handle the new generation. The study also didn't account for the impact to neighboring grid systems, instead focusing on a high-level overview of impacts.

PJM examined the impacts on transmission lines 100 kV and higher across the entire footprint, identifying thermal violations as part of the first phase. The study does not include any generation deactivations announced after Oct. 1, 2020, including those after the 2022/23 Base Residual Auction.

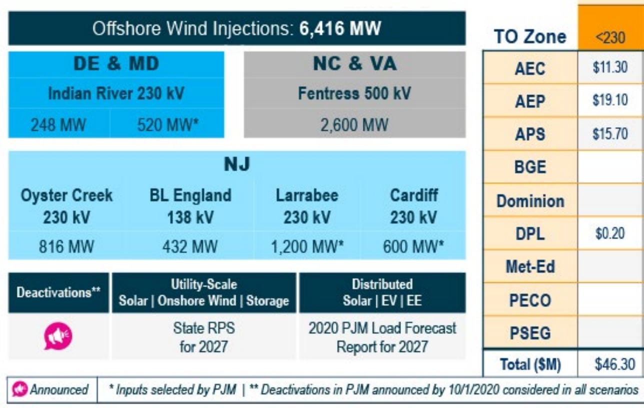
Bernstein said the modeling in the study does include the Transource Independence Energy Connection (IEC) transmission project that was expected to be built between Pennsylvania and Maryland. The project was rejected by the Pennsylvania Public Utility Commission in May, but Transource is challenging the decision in court. (See *Transource Tx Project Rejected by Pa. PUC* and *Transource Challenges Pa. PUC Decision in Court*.)

Study Results

Jonathan Kern, PJM principal engineer, presented study results that examined two different timeframes for development: a short-term window looking at goals to 2027 and a long-term window extending to 2035.

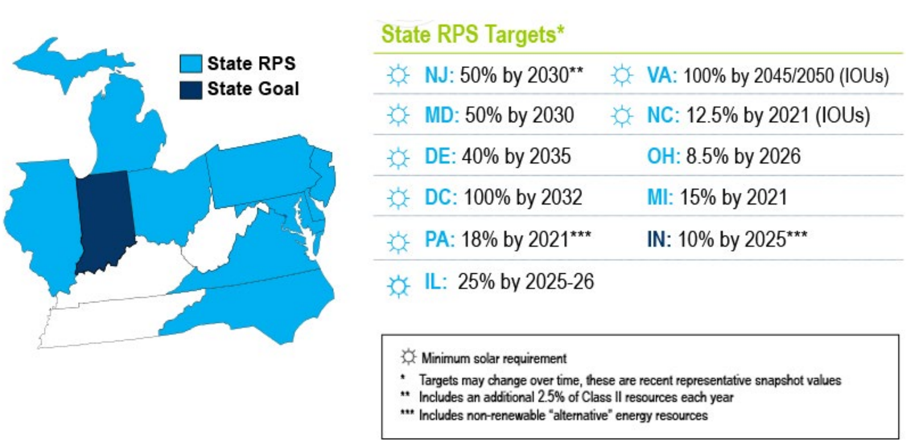
Scenario 1 was the only short-term study conducted by PJM, modeling RPS targets across the RTO along with six different onshore wind injection points designated to handle 6,416 MW of offshore wind. The scenario also looked at utility-scale solar, onshore wind and storage units, along with distributed solar, electric vehicle and energy efficiency values included in the *2020 PJM Load Forecast Report*.

Scenario 1 estimated transmission upgrade costs came in at $627.34 million, Kern said, with the largest expenses in the PECO Zone at $311 million and the BGE Zone at $173.5



TO Zone	Upgrades (kV) <230	230 & 345	500	Transformer	Upgrade Cost ($M)
AEC	$11.30			$5.34	$16.64
AEP	$19.10				$19.10
APS	$15.70				$15.70
BGE			$173.50		$173.50
Dominion		$22.50		$34.00	$56.50
DPL	$0.20				$0.20
Met-Ed		$5.20			$5.20
PECO		$5.40	$255.60	$50.00	$311.00
PSEG		$29.50			$29.50
Total ($M)	$46.30	$62.60	$429.10	$89.34	$627.34

Scenario 1 results from PJM renewable study | *PJM*



RPS requirements among PJM states | *PJM* million. Kern attributed those high costs to the necessary upgrade of an overloaded 500 kV tie line that required reinforcement.

Kern said the market efficiency analysis for Scenario 1 demonstrated decreased gross load payments, especially for coastal states.

"For the most part, the costs were relatively uniform for Scenario 1," he said.

The four remaining long-term scenarios involved minor variations in the modeling, mostly around changes in the offshore wind assumptions.

Scenario 2 modeled offshore wind injections of 14,416 MW at nine different onshore injection points, Kern said, calling it a "substantial increase" in the amount of offshore wind set to come online between 2027 and 2035.

Scenario 2's estimated cost was about $2.46 billion. Each state with RPS requirements had increased renewable penetration in the scenario, Kern said, with the Dominion Zone expected to take on 16,000 MW of added solar by 2035. Along with the additional offshore wind, Dominion Zone transmission upgrade costs exceeded $1 billion.

Scenario 4 modeled 17,016 MW of offshore wind injections, including an additional 2,600 MW at the Fentress Substation in Virginia. Costs under the scenario jumped to more than $3.2 billion, with the Dominion Zone accounting for $1.8 billion.

Kern said PJM identified possible opportunities for regional solutions to reach goals, especially in the long-term scenarios. More than 150 network upgrade requirements would be necessary in the long-term scenarios.

"This is a very high-level analysis," Kern said. "It didn't include all PJM tariff facilities, and we didn't consult local transmission owners to examine their systems."

Stakeholder Reaction

Tom Rutigliano, an advocate with the Natural Resources Defense Council's Sustainable FERC Project, said PJM's renewable study should serve as a model for grid operators across the country as they begin to make plans for the grid of the future.

Rutigliano called the study an "important first step" that showed the advantages of coordinated planning among PJM and its states instead of independently building projects. He said current planning procedures can become "piecemeal" as transmission upgrades are done and paid for by each new project developer.

"PJM's new big-picture look should allow for much more efficient and cost-effective planning, consolidating many small projects into fewer large ones," Rutigliano said. "This type of planning, done in consultation with the states driving clean energy in the region, offers a much clearer vision of how to cost-effectively meet state goals."

Rutigliano said the multibillion-dollar price tags for line upgrades may seem large, but the totals are "surprisingly low" considering the amount of work needed to account for the new renewables. He said the transmission upgrades will represent only a small fraction of the total cost for the clean energy projects.

Transmission upgrades resulting from the necessary improvements could lead to other benefits, Rutigliano said, including addressing the estimated $528.6 million in congestion costs for 2020 *cited* in Monitoring Analytics' State of the Market Report. Rutigliano would like to see PJM conduct more market analysis to determine how much money can be saved through transmission investment.

"We expect FERC to pay close attention to this problem as it works on its major transmission reform effort," Rutigliano said. "Work like this recent PJM study shows us that large-scale planning and coordination between states and grid operators has much to offer." ■

PJM Operating Committee Briefs: Aug. 12, 2021

COVID-19 Update

Stakeholders continued to question PJM's stance on vaccinations for its employees during last week's Operating Committee meeting.

After Paul McGlynn's monthly report on PJM's operations plan in response to COVID-19, Paul Sotkiewicz of E-Cubed Policy Associates again asked when the RTO intends to mandate vaccinations for all employees working on the campus. Sotkiewicz has brought up the vaccine issue at several consecutive OC meetings. (See "COVID-19 Update," *PJM Operating Committee Briefs: July 15, 2021*.)

McGlynn said PJM is "still in the same place" and not currently requiring a vaccine for its staff. He said PJM continues to monitor the situation and the metrics of the pandemic and will make changes to procedures when necessary.

Sotkiewicz said he intends to ask the question at OC meetings "until the answer changes."

Calvin Butler, Exelon Utilities CEO, receives a vaccination in April. | *Exelon*

He said PJM management is "being absolutely cavalier and irresponsible" to not mandate the vaccine and would like to hear directly from the PJM Board of Managers regarding the issue.

"Getting a vaccine, given the situation, should be a condition for employment, and it goes to fitness for duty," Sotkiewicz said.

PJM's Darlene Phillips, chair of the OC, said the RTO's leadership team has discussed the implications of mandating vaccines.

Ken Foladare of Tangibl said he was only speaking on his own behalf when he agreed with Sotkiewicz's stance, which Foladare said will help with "maintaining grid reliability" given the increasing positivity rate of the COVID-19 Delta variant. He said it's a "no-brainer" for PJM to mandate vaccines for staff considering the precedent set by other major employers. He would also like to see mandatory vaccinations for stakeholders attending in-person meetings unless they have a medical exemption.

Alex Stern, director of RTO strategy for PSEG Services, said "these are very challenging issues" and that utility companies around the country are currently having the same internal conversations.

Calling it "unprecedented times," Stern said there are legal complications in mandating vaccines that PJM staff need to take into consideration.

"This is extremely complicated, and the thing we need to do is not panic and allow management to act deliberately," Stern said. "I say that as an individual and not for my company."

NRBTMG Sunset Endorsed

Members unanimously endorsed sunsetting the non-retail behind the meter generation (NRBTMG) business rules issue charge.

Terri Esterly, senior lead engineer in PJM's markets automation and quality assurance department, *reviewed* the status of the NRBTMG business rules *issue charge* originally worked on at the OC in 2019. The sunsetting issue was first presented last month at the OC. (See "NRBTMG Sunset," *PJM Operating Committee Briefs: July 15, 2021*.)

Esterly said the updated Manual 13: Emergency Operations and Manual 14D: Generator Operational Requirements were endorsed at the September 2019 MRC meeting after going through the stakeholder process. (See "Non-retail BTM Generation Rules Endorsed," *PJM MRC/MC Briefs: Sept. 26, 2019*.)

The updates clarified the reporting, netting and operational requirements of NRBTMG, Esterly said, and included establishing an annual reporting process to determine the total amount of NRBTMG in PJM. He said PJM's *Capacity Exchange* system enhancements were released in 2020 to help facilitate the administration of NRBMTMG requirements.

Stakeholders completed the first three key work activities in the issue charge endorsed in 2019, including completing a review of the existing NRBTMG business rules in agreements and manuals, proposing changes to the existing rules and determining the level of NRBTMG in PJM. Key work activity 4 in the issue charge was designed to be triggered only when the total amount of NRBTMG in PJM approached a 3,000-MW cap.

Esterly said PJM *posts* the total amount of NRBTMG in the RTO each November, and it hasn't approached the cap. The NRBTMG was 1,171.5 MW in 2019 and 1,186.4 MW in 2020.

PJM proposed to sunset the NRBTMG business rules issue charge with the intent to bring it back and resume work when the 3,000-MW cap is reached.

Manual 14D Updates

Esterly also *reviewed* Manual 14D: Generator Operational Requirements *updates* to appendix A related to behind-the-meter generation (BTMG) business rules on status changes developed in MIC special sessions. He presented related changes to Manual 14G at the August Planning Committee meeting. (See "Manual 14G First Read," *PJM PC/TEAC Briefs: Aug. 10, 2021*.)

The proposed Manual 14D appendix A updates are indented to address conflicts with the Reliability Pricing Model must-offer requirement and removal from generation capacity resource status business rules, Esterly said. The updates include addressing performance obligation impacts, load impacts from status changes and participation in PJM's load response.

In a section on designating capability as a generation capacity resource and/or an energy resource, PJM added a business rule to make it clear a new service request must be submitted for the designation. Esterly said another rule was made to clarify the process to request a change from BTMG status to generation capacity resource status.

Esterly said in the section on participation in PJM load response, the RTO added the process to indicate that a BTMG unit is participating in PJM load response by providing on-site generator data.

PJM will seek stakeholder endorsement of the manual changes at the OC meeting on Sept. 10.

Manual 3A Updates Endorsed

Stakeholders unanimously endorsed a minor update to Manual 3A regarding model information and data requirements of flow devices.

Suzie Fahr, senior analyst in PJM's power system modeling department, *reviewed* the *changes* to Manual 3A: Energy Management System Model Updates and Quality Assurance.

Fahr called the manual update "fairly small," saying it resulted from a compliance review.

Section 2.2 was updated to clarify instructions for a transmission owner to add, remove and/or convert a flow device and submit the associated ratings, Fahr said. All references to a "breaker" in the section were updated to flow "device," which Fahr said more accurately described the application of flow-capable equipment.

PJM will seek endorsement of the manual update at the Markets and Reliability Committee meeting on Aug. 25 and have the new language take effect the same day. ■

— Michael Yoder

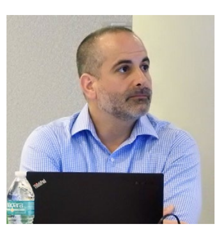
PJM MIC Briefs: Aug. 11, 2021

The *PJM* Market Implementation Committee on Wednesday endorsed rule changes on fast-start pricing, five-minute dispatch, solar-battery hybrids and an issue charge over the handling of energy efficiency in the capacity market. It also heard first reads on other manual revisions and Buckeye Power's proposed changes to capacity transfer rights, which sparked opposition from the Independent Market Monitor (IMM).

Fast-start Pricing Revisions Endorsed

Stakeholders endorsed revisions to three manuals addressing the implementation of fast-start pricing.

The changes were endorsed with 228 votes in favor (94%) versus 14 votes against adoption (6%) despite concerns from the IMM.



Phil D'Antonio, PJM | © RTO Insider LLC

Phil D'Antonio, manager for PJM's real-time market operations, *reviewed* revisions to *Manual 11: Energy & Ancillary Services Market Operations*, *Manual 18: PJM Capacity Market* and *Manual 28: Operating Agreement Accounting*. The revisions were first introduced last month. (See "Fast-start Pricing Manual Revisions," *PJM MIC Briefs: July 14, 2021*.)

D'Antonio said there were no changes from the red-line language in the manuals when they were presented in July.

FERC accepted PJM's filing in an order issued in May on its fast-start tariff changes with an effective date of July 1. (See *FERC Accepts PJM Fast-start Tariff Changes*.) PJM filed a *request* to move the effective date to Sept. 1 to avoid

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implementation during the summer peak period, which the commission *approved*.

The fast-start pricing order, which necessitated manual changes, included the implementation of separate dispatch and pricing runs in day-ahead and real-time markets, the defining of fast-start resources as those with a total time to start and minimum run time of less than or equal to one hour and the offer of lost opportunity costs (LOC) to provide incentives to follow dispatch.

Section 2.1 of Manual 11 was reorganized to include new sections on fast-start-capable resources, fast-start-capable adjustment processes and eligible fast-start resources. Other manual changes featured new day-ahead sections, including energy offers used in day-ahead price calculations and day-ahead integer relaxation (a process allowing the commitment status for a fast-start resource to vary between zero and one, inclusive of zero and one).

Updates to Manual 18 included a footnote added to section 8.4A clarifying scheduled megawatts used for "excusal and bonus purposes" in performance assessment interval (PAI) settlements calculated using dispatch run locational marginal pricing (LMP).

Manual 28 is expanded with a section on dispatch differential lost opportunity cost credits, which will provide incentives for resources dispatched down in the security-constrained economic dispatch (SCED) to continue following PJM's dispatch instructions to address the "inflexibility" of fast-start resources. It also includes an offset to avoid the double counting of commitment costs.

Zhenyu Fan, PJM senior engineer, *reviewed* fast-start implementation and metrics, saying the RTO continues to monitor fast-start on a daily basis "for quality control and risk mitigation." He said PJM is ready to fully implement fast-start pricing on Sept. 1.

Catherine Tyler, Monitoring Analytics | © *RTO Insider LLC*

Catherine Tyler of the Independent Market Monitor *provided* an overview of the IMM's concerns regarding the formation of ancillary service market clearing prices under some fast-start conditions.

Tyler originally called attention to section 4.2.9: Synchronized Reserve Market Clearing Price Calculation in Manual 11 at the July MIC meeting. The updated manual languages states, "In the pricing run, the cost of the marginal synchronized reserve resource may also include amortized start-up and amortized no-load costs due to integer relaxation for eligible fast-start resources."

Tyler said the Monitor believes PJM should not implement fast-start pricing in this way because it's "not consistent with the filings and the FERC approved Operating Agreement." Tyler said the result of the change is that the commitment cost of the marginal unit for reserves is included in the reserve clearing price when there is no LOC.

"It's a detailed issue, but it's pretty straightforward to understand," Tyler said.

Carl Johnson of the PJM Public Power Coalition said he appreciated that the IMM brought the issue forward and presented an example of what it could look like in action, but he wasn't sure if a solution was being recommended.

"While we always want to get these things right, I'm not sure we're in a position to advocate for a delay from the Sept. 1 start," Johnson said.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), asked what the IMM believed the impact on costs would be if the proposed language remained the same.

Tyler said the issue doesn't occur with a "high frequency," but when it does occur the effect on prices is significant because amortized start-up and amortized no-load costs can be "quite large."

"It's a little difficult to directly quantify," Tyler said.

Paul Sotkiewicz of E-Cubed Policy Associates said he disagreed with the IMM's interpretation of the filing, calling it "much ado about nothing." Sotkiewicz said PJM's solution was "just part and parcel of co-optimization" that had already been approved by FERC.

"I think this is just a collateral attack from the IMM on PJM's use of integer relaxation versus the method preferred by the IMM," Sotkiewicz said.

Tyler said Sotkiewicz's assertion was not correct and that the FERC order was clear. Tyler clarified that the impact on reserve prices is not due to co-optimization and that it is possible to implement fast-start with co-optimization without this result occurring.

The manual changes will be voted on at the Aug. 25 Markets and Reliability Committee meeting.

5-Minute Dispatch Revisions Endorsed

Members unanimously endorsed Manual 11 updates modifying and adding transparency to five-minute dispatch rules.

Aaron Baizman, PJM lead engineer with real-time market operations, *reviewed* the revisions to *Manual 11: Energy & Ancillary Services Market Operations* that were first presented at the July MIC meeting. (See "5-Minute Dispatch Manual Revisions," *PJM MIC Briefs: July 14, 2021*.)

Stakeholders unanimously endorsed the proposed solution and associated tariff and Operating Agreement *revisions* at the April MRC and MC meetings. (See "Long-term 5-minute Dispatch Endorsed," *PJM MRC/MC Briefs: April 21, 2021*.)

Baizman highlighted section 2.3.3.1: Capacity Resource Offer Rules, which adds a rule stating hydropower resources fall under the intermittent generation resource category and that hydropower resources that are committed capacity resources "shall meet the must-offer requirement by self-scheduling" and offering as a must-run resource.

A separate section on pump storage hydropower capacity said resources have to offer as must run or use the PJM pump storage optimization model in the day-ahead market. He said the two hydropower changes were made to conform with existing language in section K of the tariff.

Baizman said Section 2.5: Real-time Market Clearing Engine saw many edits with multiple diagrams updated and additional information added for real-time SCED optimization concerning the marginal resource identification process.

The Manual 11 changes will be voted on at the August MRC meeting.

Solar-Battery Hybrid Proposal Endorsed

Stakeholders endorsed a PJM *proposal* to clarify market participation by solar-battery hybrids and other mixed technology resources.

The PJM proposal, which has been worked through the DER and Inverter-based Resources Subcommittee (DIRS), received 235 votes in support (99%) with three stakeholders voting against. Members also unanimously voted to support the proposal over maintaining the status quo on the issue.

Andrew Levitt of PJM's market design and

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economics department reviewed the RTO's solar-battery hybrid resources issue. Levitt introduced the proposal at the July MIC meeting. (See "Solar-battery Hybrid Resources," *PJM MIC Briefs: July 14, 2021*.)

The solar-battery hybrid resources problem statement and issue charge were originally brought forward by PJM staff and approved by stakeholders at the June 2020 MIC meeting to clarify business rules. (See "Solar-Battery Hybrids," *PJM MIC Briefs: June 3, 2020*.)

The PJM proposal provides updates to the RTO's governing documents and business manuals to clarify several aspects of market participation by solar-battery hybrid resources. The proposal introduces new definitions, including "mixed technology facility," "hybrid resource," "co-located resource" and "open-loop hybrid resource," while a "standalone energy storage resource" is defined to draw a distinction between hybrid resources and other energy storage resources.

Levitt said the definitions are required to clarify new resource types and apply new or existing business rules to each resource type. For co-located resources, Levitt said, the proposal clarifies that market participation occurs separately for each underlying resource type and that metering and telemetry are required both at the point of interconnection (POI) and on one or all the underlying resource types behind the POI.

Levitt said a new "family" of models was created to include three types of solar-battery hybrid resources in the energy market:

- An existing standalone energy storage resource (ESR) participation model;
- An open-loop solar-battery hybrid resource model that can charge from grid, which is a type of ESR, and;
- A closed-loop solar-battery hybrid resource model that cannot charge from grid and is not a type of ESR.

Market Monitor Joe Bowring said the IMM "totally" supported PJM's proposal, saying it "enhances competition."

Dominion Energy's Jim Davis *reviewed* an alternative proposal, which was identical to PJM's proposal except for a provision pertaining to the regulation market. Stakeholders rejected the Dominion proposal, with 69 members (34%) voting in favor.

The PJM proposal will move on to the MRC for consideration.

Energy Efficiency Add-back Issue Charge Endorsed

Members unanimously endorsed an issue charge presented by the IMM on calculating the energy efficiency (EE) add-back.

Monitor Bowring *reviewed* the *problem statement* and *issue charge* addressing the calculation. Bowring presented the issue at the July MIC meeting. (See "Energy Efficiency Add-back," *PJM MIC Briefs: July 14, 2021*.)

Bowring said the current treatment of the EE add-back in clearing the Base Residual Auction does not require it to match the effect of EE on the capacity market's variable resource requirement (VRR) curve. Bowring said the result of the treatment is an artificial increase in the BRA clearing price even though EE was originally designed to be neutral.

The proposed solution calls for rewriting the manual language to permit PJM to calculate the EE add-back in the capacity market clearing so that the total EE add-back megawatts offsets the total cleared EE megawatts in the BRA.

The IMM initially requested that the "quick-fix" process be used to complete work on the issue so that PJM can use the correct EE add-back data for the upcoming 2023/24 BRA in December, but some stakeholders requested an additional month of discussion to explore options. The issue charge was amended to use the "CBIR Lite" (Consensus Based Issue Resolution) process and take two months instead of one to complete it.

After the vote, Jeff Bastian, senior consultant of PJM's market operations, *provided* education on how EE is treated in the Reliability Pricing Model (RPM) for the capacity auction. Lisa Morelli of PJM facilitated a discussion on the development of the CBIR *matrix*.

Stakeholders made a few suggestions for interest identification of the issue on the matrix. In addition to minimizing the impact of the add-back process on clearing prices, stakeholders also called for preventing an adverse reliability impact from double-counting EE as a capacity resource and as a load forecast reduction, and ensuring a timely auction clearing.

The issue will be discussed again at the Sept. 9 MIC meeting.

Manual 15 Revisions

Tom Hauske of PJM's performance compliance department *provided* a first read of the *Manual 15: Cost Development Guidelines* revisions regarding the incremental and no-load energy offer developed in the Cost Development Subcommittee (CDS). PJM also provided *Operating Agreement* and *tariff* revisions related to the manual changes.

Hauske said there are "quite a few changes" proposed in the manual. The main ones involve revising the no-load cost and incremental energy offer definitions to "more clearly define what costs can be included" and how they should be calculated.

Hauske said the biggest manual changes come in section 2.3 for the definition of

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incremental energy cost, which says, "The incremental energy cost is the cost in dollars per MWh of providing an additional MWh from a synchronized unit." The changes also include methods for market sellers to submit sloped, stepped or block loaded incremental offers into PJM's Markets Gateway System.

The committee will be asked to endorse the Manual 15 revisions at the September MIC meeting; the OA and tariff will be voted on by the Markets and Reliability Committee.

RPM Capacity Transfer Rights

Kevin Zemanek, director of system operations for Buckeye Power, *provided* a first read of Buckeye's proposal regarding the allocation of capacity transfer rights (CTRs).

Stakeholders originally endorsed Buckeye's issue charge at the March MIC meeting with 79% support. (See "RPM Issue Charge Endorsed," *PJM MIC Briefs: March 10, 2021*.)

Zemanek said under the RPM, CTRs return to load-serving entities capacity market congestion revenues that occur when there's a difference between the prices paid by load and market revenue received by cleared resources. He said CTRs permit LSEs with load inside a constrained locational delivery area (LDA) to receive a credit for the import of capacity from a lower-priced region.

Zemanek said PJM does not have a way to allocate CTRs directly to an LSE with network resources outside a constrained LDA but whose resources have been designed as deliverable on the LSE's network integration transmission service agreement. Instead, Zemanek said, PJM allocates CTRs pro rata to each LSE serving load in the LDA or zone based on the LSE's share of the zonal unforced capacity obligation.

Buckeye's proposal calls for first allocating zonal CTRs to LSEs with historic generation resources identified as network resources in a network integration transmission service agreement (NITSA). The allocated CTRs will be "sufficient to meet the LSE's daily unforced capacity (UCAP) load obligation but shall not exceed the total amount of the LSE's generation capacity as identified on the LSE's NITSA."

The proposal would recognize generation resources and transmission rights that existed prior to the implementation of RPM but would also terminate upon the retirement of a resource or a change in the designated resource status in the NITSA. The new rules would be implemented at the next available CTR allocation process following FERC approval.

"We're not changing the calculations for transmission constraints, and we're maintaining reliability by keeping the total amount of CTRs the same," Zemanek said.

Bowring opposed the proposed changes, saying that Buckeye's approach was an attempt to use a non-market contract path approach rather than the market network approach that the CTR design was based on. He said the Buckeye approach meant that the company would be paid more and other market participants would be paid less. "It is a zero-sum game," Bowring said.

Bowring also said the Buckeye proposal was inconsistent with the way in which the value of CTRs is defined based on delivery year forecasts rather than the results of the capacity base auction.

Bastian *reviewed* the megawatt quantity of qualified requests by zone to assist participants in evaluating the impact of the Buckeye proposal. Buckeye has said the impact of the current rules vary from year to year; it said the rules cost it $10 million in the 2015/16 delivery year and $2.5 million in 2016/17.

The committee will be asked to endorse the proposal at the September MIC meeting. ■

— Michael Yoder

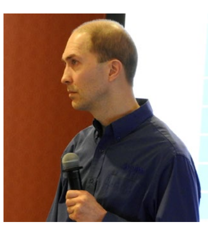
PJM PC/TEAC Briefs: Aug. 10, 2021

Planning Committee

Winter/Light-load Generator Deliverability Update

PJM is looking to modify generator deliverability tests for light-load and winter periods as more renewable energy is set to come online in the coming years.

Jonathan Kern of PJM's transmission planning department *provided* an update on the winter and light-load generator deliverability analysis and the proposed changes to the generator deliverability test for the light-load and winter periods at last week's Planning Committee meeting.



Jonathan Kern, PJM | *© RTO Insider LLC*

Kern said the purpose of the changes is to "consider the rapidly evolving" resource mix in PJM's planning process and to "support operational flexibility" by planning the grid to handle the expected evolving resource mix.

PJM is looking to modify each of the generator deliverability tests, Kern said, but wanted to start with the light load and winter generator deliverability procedures. Kern said those procedures have been "relatively unchanged" for many years and need better accounting for the expected higher variability of renewable resources in dispatching.

The current light-load procedure starts with a load level at 50% of the annual peak, Kern said, and is representative of November through April and the hours of 12-5 a.m. PJM is proposing to keep 50% of the annual peak but wants to shift the definition of the period of the light load to use load hours between 40% and 60% of the annual peak and to also use daytime hours and other periods of the year reaching the same 50% load level.

Kern said the change in hours is driven by the addition of solar power in the daytime hours and not simply looking at wind resources as PJM had done in the past for the light-load procedure.

"We're currently not accounting for solar in the light-load test because it's focused on the nighttime period," Kern said. "So we want the light-load test to cover a broader set of hours."

For the ratings in the light-load procedure, PJM is proposing using 59 F as the default temperature set. The light-load procedure currently uses 95 F as the default, which PJM determined is "too conservative," Kern said.

He said PJM planning engineers spoke with several subject matter experts in operations and markets to look at historical dispatch patterns and conducted a "significant amount of testing" to develop several proposals to modify the base case dispatch, the external and internal interchange and generator ramping procedures for both winter and light-load.

PJM is still working on proposal assumptions by conducting additional analysis, Kern said, and is formulating updated language in Manu-

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al 14B to be brought to the PC for the first read before the end of the year.

Carl Johnson of the PJM Public Power Coalition asked if PJM will issue a report to give stakeholders more insight into the nature of the proposed changes and what could be expected in the future as more renewables come online.

Kern said developing the grid of the future will be one of PJM's primary focuses over the next few years and it will be issuing white papers and reports on how the grid will need to evolve and what the RTO's role will be in its evolution.

Manual 20 Endorsed

Stakeholders unanimously endorsed the cover-to-cover updates of *Manual 20: Resource Adequacy Analysis*.


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

Patricio Rocha Garrido of PJM's resource adequacy department *reviewed* the revisions to the manual, saying the minor changes included cleaning up outdated and redundant language and ensuring the manual language follows current PJM processes. The changes were first introduced at the June PC meeting. (See "Manual 20 First Read," *PJM PC/TEAC Briefs: July 13, 2021*.)

The changes included removing the Reliability Pricing Model (RPM) timeline from section 1.2 of Manual 20 because it already exists in Manual 18 and clarifying language around the time period used in the creation of the load model and aspects of the capacity model in section 3.2.

Rocha Garrido said one complication in the Manual 20 changes was a parallel effort at the MRC to update the manuals resulting from discussions addressing the effective load-carrying capability (ELCC) for limited-duration and intermittent resources. Stakeholders endorsed the revisions at the July Markets and Reliability Committee meeting. (See "ELCC Manuals," *PJM MRC/MC Briefs: June 23, 2021* and "Consent Agenda Manual Endorsements," *PJM MRC/MC Briefs: July 28, 2021*.)

The ELCC changes were in section 5 of Manual 20, Rocha Garrido said, which include an overview of PJM's ELCC analysis, a description of the load model used and a description of the loss of load expectation calculation.

Members will be asked to endorse the changes at the Aug. 25 MRC meeting.

Manual 14G First Read

Terri Esterly, senior lead engineer for PJM's markets automation and quality assurance department, *provided* a first read of *updates* to Manual 14G: Generation Interconnection Requests regarding the behind-the-meter generation (BTMG) business rules on status changes.

Esterly said the changes were the result of work done at special sessions of the Market Implementation Committee to review the existing BTMG business rules and identify gaps in the rules. Esterly presented related changes to Manual 14D at the August Operating Committee meeting. (See "Manual 14D Updates," *PJM Operating Committee Briefs: Aug. 12, 2021*.)

The updates include language on megawatts changing status from BTMG, where they can net against the load, to the PJM market resource status. Esterly said the updates were intended to address conflicts with the Reliability Pricing Model (RPM) must-offer requirement and removal from generation capacity resource status business rules as well as to clarify and "adequately document" the processes related to status changes.

Esterly said most of the updates to the manual are in section 1.6.1 to clarify information required in an interconnection request to designate capability as a generation capacity or energy resource. The updated language includes a list of information required in a new services request for a BTMG unit, a definition of behind-the-meter load and a clarification on how to determine the maximum host/process loads.

The committee will be asked to vote on the manual changes at the Aug. 31 PC meeting.

Transmission Expansion Advisory Committee

Generation Deactivation Notification

Phil Yum of PJM *provided* an update on 14 recent generation deactivation notifications totaling nearly 8,000 MW at last week's Transmission Expansion Advisory Committee meeting.

Houston-based GenOn Holdings requested the Sept. 15 deactivation of the 627-MW coal-fired Avon Lake 9 Generating Station and 21-MW oil-fired Avon Lake 10 unit, both located in Ohio's American Transmission Systems Inc. (ATSI) transmission zone, and the 568-MW coal-fired Cheswick Generating Station, in the Duquesne transmission zone in Pennsylvania.

GenOn also requested the May 31, 2022, deactivation of 1,233 MW from the coal-fired Morgantown Generating Station units 1 and 2, located in the PEPCO transmission zone in Maryland.

Yum said a reliability analysis for all five units identified some reliability violations but that new and existing baseline projects will "resolve" the identified impacts and the units can retire as scheduled.

Exelon requested that its two Byron nuclear units, both in the ComEd transmission zone in Illinois, be deactivated Sept. 14 and 16. The company originally announced in 2019 its intention to retire the units. It then reiterated its intention before the Illinois legislature failed to pass an energy package that would support the plants. (See *Biden's Support for Nuclear 'Too Late' to Save Exelon Plants*.)

Yum said a reliability analysis identified fixable issues for both Byron units and that they can retire next month.

NRG Energy requested that the coal-fired Waukegan Generating Station Units 7 and 8 and the 510-MW coal-fired Will County Generating Station Unit 4, all located in the ComEd zone, be deactivated on May 31, 2022. Yum said a reliability analysis was completed and the units can retire as scheduled.

NRG also requested a May 2022 deactivation of its coal-fired 412-MW Indian River 4 Generating Station, but the reliability analysis identified the need to keep the plant operating. Yum said PJM identified seven different thermal violations, estimated to cost $117.4 million. PJM and NRG are working on solutions to allow for deactivation.

PJM also received generation deactivation notices for three additional units for May 31, 2022, including Talen Energy's 115-MW gas- and oil-fired Pedricktown Power Plant in the Atlantic City Electric transmission zone and the 120-MW Newark Bay Power Plant in the Public Service Enterprise Group transmission zone, as well as Vistra's 1,320-MW coal-fired William H. Zimmer Power Plant in the Duke Energy Ohio/Kentucky transmission zone. Yum said a reliability analysis is underway for each unit.

A total of 7,918 MW of generation is set to be deactivated. ■

— Michael Yoder

SPP News

MISO, SPP Offer Idea on Joint Interconnection Tx Allocation

By Amanda Durish Cook

MISO and SPP have shared an early concept for cost allocation on joint transmission projects intended to ease their crowded interconnection queues.

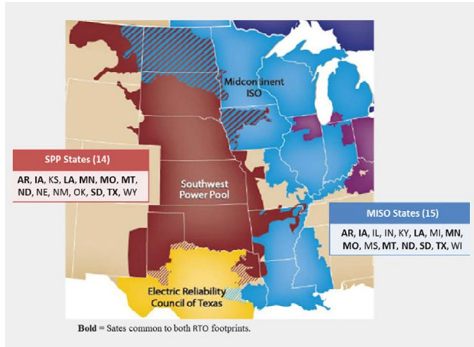
The grid operators envision a four-stage process to split costs, including reliability and benefits analyses, project review and approval, and a study on what individual interconnection customers would owe for projects.

MISO and SPP surprised stakeholders last month by seeking stakeholders' ideas on how to split costs on joint targeted interconnection queue projects instead of proposing their own allocation method. (See *MISO, SPP Solicit Ideas on Allocating Joint Tx Costs*.)

In late June, the RTOs introduced two expensive cluster projects that stand to eliminate most flowgate congestion. The $424 million and $728 million options traverse South Dakota, Minnesota and Missouri. (See *MISO, SPP Name Projects to Help Queue Troubles*.)

"I want to stress to everyone that we're in the initial stages of setting a cost allocation for this effort," SPP's Neil Robertson told stakeholders during a virtual meeting Friday.

SPP Director of Seams and Tariff Services David Kelley said the RTOs are striving for an allocation method "flexible enough for future applications" between the two.



| Organization of MISO States

"We want to design something that can be applied to various situations in the future when pertinent," Robertson said.

But Kelley said if it's too difficult to create a multiuse allocation, MISO and SPP will settle for single-use.

MISO and SPP said the lion's share of project costs will be divided between load and generator interconnection customers. But while the grid operators have a quantifiable way to assign project costs to load via an adjusted production cost calculation, they're not yet sure how to nail down quantifiable benefits to interconnection customers.

"We need to keep this simple, in an approach to a cost allocation, where possible," Robertson said.

Missouri Public Service Commission economist Adam McKinnie asked if the RTOs have any idea of how to estimate interconnection customers' benefits.

"You asked the marquee question," Robertson said. He added he's been asking interconnection customers if there's a broader way to socialize costs of new transmission among them beyond clustering the customers that require the same transmission upgrade.

He said MISO and SPP want to "assess a fair fee" to interconnection customers but that it would be a "very significant technical process" to crunch an individual customers' unique costs. Robertson said the RTOs will probably calculate an aggregate benefit for a class of interconnection customers and may assess individual customers a per-megawatt fee based on their impact factor on the transmission project.

Robertson said stakeholders will also have to discuss how the targeted interconnection projects will receive initial funding.

The RTOs said they'll have a more detailed proposal in the coming months. ■

SPP MMU Issues State of the Market Report for 2020

SPP's Marketing Monitoring Unit on Thursday released its annual State of the Market report for 2020. The Monitor has scheduled a webinar for Aug. 25 at noon CT to discuss both it and the Spring 2021 quarterly market report, released late last month.

The MMU shared a draft of the annual report last month with SPP's Board of Directors and Members Committee. (See "MMU Briefs Draft Market Report," *SPP Board of Directors/Members Committee Briefs: July 26-27*.)

The annual report's key conclusions include:

- Wind generation accounted for the largest percentage of total energy produced, at 31.3%, just ahead of coal at 31%. SPP's nameplate wind capacity increased to just over 27.3 GW in 2020, up about 22% from 2019.
- Day-ahead market prices averaged $17.69/MWh and real-time prices averaged $16.62/MWh, a 20% drop for both from 2019 and the lowest since the Integrated Marketplace went live in 2014. The average gas price at the Panhandle Eastern hub was $1.72/MMBtu, down 11% from $1.93 the year before.
- Total electric consumption was down about 3% in 2020 as a result of the COVID-19 pandemic. The annual peak load of 49,569 MW was also 3% lower than in 2019.

The Monitor made three new recommendations, all unrelated to the February winter storm: updating market and outage requirements to improve transmission congestion rights' funding; improving market-to-market efficiencies by working with MISO; and raising the offer floor to $100/MW. ■

— Tom Kleckner

| SPP Market Monitoring Unit

SPP News

SPP Pondering Changes to M2M Summaries

RTO has Accrued $152.3M in Settlements from MISO

By Tom Kleckner

SPP staff are re-evaluating the level of detail they provide stakeholders for their market-to-market (M2M) activities with MISO.

The reports, intended to be monthly, have left staff playing catchup in recent years. On Thursday they were only able to share with the Seams Advisory Group a summary of May's M2M activity, which resulted in a $6.3 million settlement in SPP's favor.

When the group next gathers virtually in September, it will be expecting to hear summaries from June and July. The reports summarize M2M settlements for binding flowgates as a result of redispatch based on the non-monitoring RTO's market flow in relation to firm flow entitlements.

Including May, SPP has now accrued $152.3 million in settlements from MISO since the two RTOs began the M2M process in March 2015.

Staff are considering setting a threshold for flowgates with six-figure or greater settlement totals to identify "the big drivers." May's summary included 43 permanent and temporary flowgates that were binding for 1,405 hours. The $100,000 threshold would have reduced that total to 10 flowgates.

"At some point, does the level of market-to-market payments trigger some action in regard to transmission analysis?" Advance Power Alliance's Steve Gaw asked. "Everybody sees this as useful information, but at some point, this should translate into either an analysis of a better way to handle this between markets or whether there's a transmission-congestion analysis that needs to be done."

Clint Savoy, SPP's senior interregional coordinator, said the M2M data "informally informs our own regional and interregional processes."

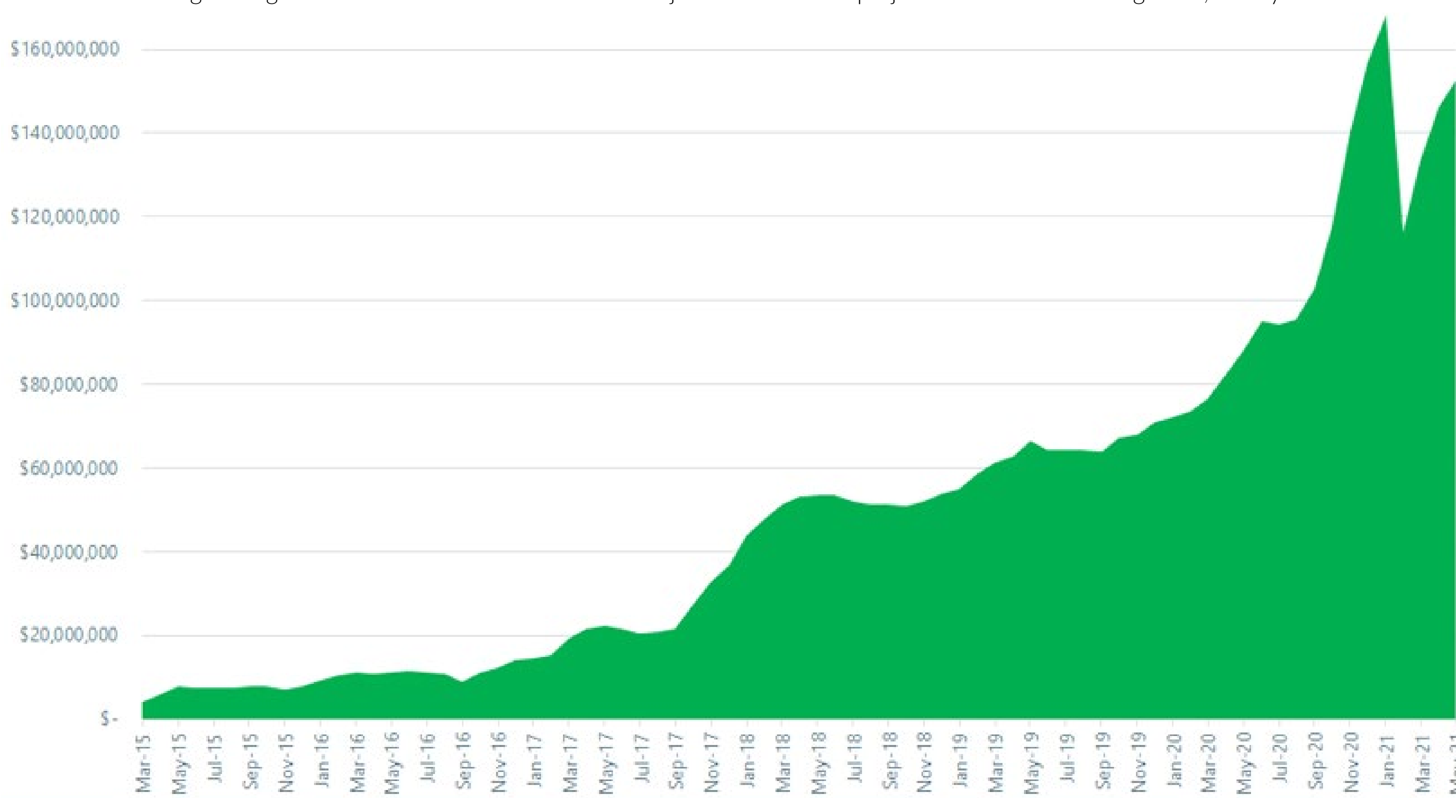
"We're starting to get some traction and movement on … processes between SPP and MISO," he said.

SPP and MISO are involved in several initiatives across their seam. Of course, there's the work to find joint transmission projects that would help reduce the RTOs' crowded interconnection queues. Their staffs met with stakeholders Friday to discuss how best to allocate costs. (See related story, *MISO, SPP Offer Idea on Joint Interconnection Tx Allocation*, p.31.)

The RTOs have also reached an agreement in principle over affected-system studies. Staff are working to memorialize the policy changes in their joint operating agreement. SPP and MISO are also trying to develop a targeted market efficiency project process similar to MISO's effort with PJM.

That's separate from the work SPP is undertaking to strengthen its seams agreement provisions with neighboring entities to ensure "adequate emergency assistance and fairly compensate emergency energy" during situations like February's winter storm. The RTO imported more than 7.5 GW of energy from its neighbors during the storm, the highest since the Integrated Marketplace went live in 2014.

"As usual, we have a lot of balls in the air with all of our neighbors," Savoy said. ■



M2M payments to SPP from MISO are nearly back to the high-water market for the February winter storm. | *SPP*

Company News

PSEG to Sell Fossil Units to ArcLight Capital

$2.2B+ Loss Expected as Utility Seeks to Reduce Merchant Generation

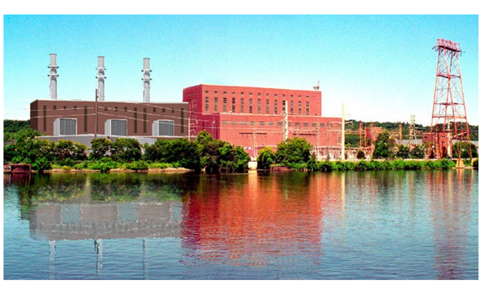
By Rich Heidorn Jr.

Public Service Enterprise Group has agreed to sell its 6.7-GW fossil fuel fleet in New Jersey, Connecticut, New York and Maryland to ArcLight Capital Partners for $1.92 billion to further its transformation to a primarily regulated electric and gas utility.

The move — announced Thursday, only two months after PSEG sold off its solar generation unit — will eliminate virtually all the company's generation except for its 3.8 GW of nuclear capacity in New Jersey and Pennsylvania.

"A year ago, we announced the strategic review of PSEG's non-nuclear generating assets in line with our long-term focus on regulated utility growth, improving our business mix and enhancing an already compelling environmental, social and governance profile," PSEG CEO Ralph Izzo said in a statement. "With today's agreement, which is the result of a robust sale process, PSEG is on track to realize a more predictable earnings profile. Further, this transaction continues our evolution toward a clean energy, infrastructure-focused company that will enable our increasingly low-carbon economy."

Escaping the uncertainty of merchant generation business will come with a substantial write-down from the power plants' $4.5 billion book value. PSEG said it will record a pre-tax impairment charge of $2.15 billion to $2.225 billion, employee severance and retention costs up to $25 million, debt redemption costs — including a make-whole premium — of approximately $280 million to $340 million, and "potential impacts on employee pension and other post retirement plans, environmental remediation costs and other items."



PSEG's Bethlehem Energy Center, an 817-MW combined cycle plant in New York | *PSEG*

NAME	LOCATION	TOTAL CAPACITY (MW)	% OWNED	OWNED CAPCITY (MW)	PRINCIPAL FUELS USED
STEAM:					
Bridgeport Harbor 3 (A)	CT	383	100%	383	Coal
New Haven Harbor	CT	448	100%	488	Oil/Gas
Total Steam		**831**		**831**	
NUCLEAR:					
Hope Creek	NJ	1,180	100%	1,180	Nuclear
Salem 1 & 2	NJ	2,285	57%	1,311	Nuclear
Peach Bottom 2 & 3 (B)	PA	2,549	50%	1,275	Nuclear
Total Nuclear		**6,014**		**3,766**	
COMBINED CYCLE:					
Keys	MD	761	100%	761	Gas
Bergen	NJ	1,245	100%	1,245	Gas/Oil
Linden	NJ	1,300	100%	1,300	Gas/Oil
Sewaren 7	NJ	538	100%	538	Gas/Oil
Bridgeport Harbor 5	CT	484	100%	484	Gas
Bethlehem	NJ	817	100%	817	Gas
Kalaeloa	HI	208	50%	104	Oil
Total Combined Cycle		**5,353**		**5,249**	
COMBUSTION TURBINE:					
Essex	NJ	81	100%	81	Gas/Oil
Kearny	NJ	456	100%	456	Gas/Oil
Burlington	NJ	168	100%	168	Gas/Oil
Linden	NJ	336	100%	336	Gas/Oil
New Haven Harbor	CT	130	100%	130	Gas/Oil
Bridgeport Harbor 4	CT	17	100%	17	Oil
Total Combined Cycle		**1,188**		**1,188**	
TOTAL PSEG POWER PLANTS		**13,386**		**11,034**	

ArcLight Capital Partners agreed to purchase PSEG's 6.7-GW fossil generation fleet, 13 units in New Jersey, Connecticut, New York and Maryland. The sale does not include the Bridgeport Harbor 3 combustion turbine, which retired May 31, or the Kalaeloa combined cycle plant in Hawaii. | *PSEG 10-K filing, March 2021*

Sale proceeds will be primarily used to pay down PSEG Power's debt, company officials told stock analysts in the second quarter earnings call last month. (See *PSEG Seeking to Sell Fossil, Solar Generation*.)

The deal does not include Bridgeport Harbor 3, a 383-MW coal-fired combustion turbine in Connecticut, which retired May 31.

Also excluded is PSEG's 50% share in the 208-MW oil-fired Kalaeloa combined cycle plant in Hawaii. PSEG spokesperson Marijke Shugrue declined to comment on the company's plans for the plant, which is co-owned by limited partner Harbert Power Fund V, a unit of *Harbert Management Corp.*

In its 10-Q *filing* Aug. 9, PSEG disclosed that it had already taken a pre-tax charge of $519 million to recognize that the cash flows and fair value of its fossil units in ISO-NE were less than their carrying value as of June 30. The company's "impairment assessment" found that its fossil units in PJM and NYISO did not require a write-down as long as they remained classified as "held-for-use." PSEG reported its combined cycle plants had a 44.3% capacity factor in the first half of 2021, the same as a year earlier.

As a result of the sale, PSEG said it was updating its full-year 2021 non-GAAP operating earnings guidance to $3.50 to $3.65/share, from $3.40 to $3.55/share, "reflecting the cessation of depreciation expense and lower interest expense related to the sale of the PSEG Fossil assets and repayment of PSEG Power's outstanding debt."

The sale to ArcLight, which is subject to review by the Justice Department and FERC, is expected to be completed late in the fourth quarter of 2021 or the first quarter of 2022.

For *ArcLight*, a Boston-based private equity firm, the deal is just the latest in a series of more than 110 acquisitions and 69 exits since its founding in 2001. The company invests in energy infrastructure assets with "substantial growth potential, significant current income and meaningful downside protection," including renewable and fossil generation, oil and gas production and midstream operations such as pipelines, storage and gathering and processing.

The company did not respond to a request for comment.

In March, Generation Bridge, a unit of ArcLight Energy Partners Fund VII *announced* it would purchase 4.85 GW of generation from NRG Energy for $760 million. The company also has purchased generation from AEP and Exelon as they have also sought to reduce or exit their merchant generation. (See *Blackstone, ArcLight to Purchase AEP Merchant Plants for $2.2B* and *Exelon Selling Last Major Coal Generation in Fleet*).

Reuters *reported* that ArcLight and its limited partners, including pension funds representing Maine teachers and NFL football players, lost several hundred million dollars in their ill-fated investment in the Limetree Bay refinery in the U.S. Virgin Islands, which was shut down by environmental regulators in May. ■

Company Briefs

Gates Pledges $1.5B for Infrastructure Bill's New Climate Projects

Microsoft co-founder Bill Gates last week said his climate investment fund will commit $1.5 billion for joint projects with the U.S. government, if Congress enacts a program aimed at developing technologies that lower carbon emissions.

Gates said a fund run by his Breakthrough Energy could spend the money over three years on projects aimed at slowing greenhouse gas emissions. The Breakthrough projects, which would have to compete with other applicants for the funds, could include emissions-free fuel for planes and carbon-capture technology.

Gates also said Breakthrough would likely shift funding to Europe and Asia if the package doesn't become law.

More: *The Wall Street Journal*

Dominion Sets Carbon-reduction Fleet Goals

Dominion Energy last week announced a "Green Fleet" initiative, pledging that three-quarters of its passenger vehicles will be electric by 2030.

The company also pledged that 50% of its work trucks (including pickups, forklifts and ATVs) will either be EVs or fueled by hydrogen or natural gas. After 2030, 100% of new vehicles purchased will be powered by electricity or alternative fuels.

Dominion's vehicle fleet numbers more than 8,600.

More: *Dominion Energy*

Mass. Startup Hopes to Move a Step Closer to Commercial Fusion

Researchers at MIT's Plasma Science and Fusion Center and engineers at Commonwealth Fusion Systems have been testing an extremely powerful magnet that is needed to generate immense heat that can then be converted to electricity and, possibly, create what they believe could eventually be a fusion reactor.

Commonwealth's new magnet will be a crucial component in a compact nuclear fusion reactor known as a Tokamak, a design that uses magnetic forces to compress plasma until it is hotter than the sun. Company executives claim the magnet is a significant technology breakthrough that will make the designs commercially viable for the first time.

While they are not ready to test the reactor prototype, researchers are finishing the magnet and hope it will be workable by 2025.

More: *The New York Times*

Facebook to Build Data Center in Phoenix

Facebook last week announced plans to build a $800 million, 960,000-square-foot data center in Mesa, Ariz.

The facility will house routers, switches, servers, storage systems and other equipment to keep applications running and data secure.

Construction is underway and is expected to last a couple years.

More: *Arizona Republic*

Federal Briefs

FERC Approves MVP's Plans for New Water-crossing Method

FERC last week issued an environmental assessment for the long-delayed Mountain Valley Pipeline (MVP), signing off on the project's plans to use a different water-crossing method at some locations along its route.

MVP proposed using trenchless methods to cross 136 streams and 47 wetlands that FERC originally authorized as open-cut crossings. However, the commission's assessment released last week said the new technique would not have a significant impact on the environment as long as MVP adheres to its application and follows the commission's recommended mitigation measures. FERC also determined the trenchless crossing method would have less impact on wetlands and waterbodies than the open-cut technique.

More: *Natural Gas Intelligence*

Judge Declines to Dismiss Suit over TVA Contracts

U.S. District Judge Thomas Parker last week declined to dismiss a lawsuit brought by environmental groups against the Tennessee Valley Authority and its auto-renewing, 20-year contracts.

The groups argue that the contracts violate the TVA Act — the federal law that governs the utility — and would allow TVA to drag its feet on moving away from carbon-based sources of energy and stymy its potential efforts to reduce carbon emissions. TVA argued the agreements do not govern its power supply choices, but other, different planning documents.

Parker's ruling means the case will proceed.

More: *Memphis Commercial Appeal*

Study: Hydrogen not as 'Green' as Previously Thought

A peer-reviewed study released last week claims hydrogen may not be as climate-friendly as most say.

The study, which was published in the Energy Science & Engineering journal by Cornell and Stanford University researchers, said that most of the hydrogen used today is extracted from natural gas in a process that requires a lot of energy and emits vast amounts of carbon dioxide. Producing natural gas also releases methane. And while the natural gas industry has proposed capturing the carbon dioxide — creating what it promotes as emissions-free, "blue" hydrogen — even that fuel still emits more across its entire supply chain than simply burning natural gas.

The researchers examined the life cycle greenhouse gas emissions of blue hydrogen and accounted for both carbon dioxide emissions and methane that leaks from wells and other equipment during natural gas production. They found that the greenhouse gas footprint of blue hydrogen was more than 20% greater than burning natural gas or coal for heat.

More: *The New York Times*

State Briefs

CALIFORNIA

Hayward Plant Restarts, Cause of Explosion Unknown

The Russell City Energy Center restarted on Aug. 12, roughly three months after an explosion and fire. The cause of the explosion remains unknown.

Calpine owns the plant where on May 27, a large steam turbine exploded, sending heavy chunks of hot metal up to 1,200 feet away.

The Energy Commission said the plant, which is relying on two natural gas turbines, is needed to help supply power to the grid because of extreme heat conditions.

More: *KTVU*

Irvine City Council Pledges Carbon Neutrality

The Irvine City Council last week unanimously approved a resolution to strive to reach a zero-carbon economy by 2030. Irvine is only the third city in the state to set a carbon neutral goal.

The resolution proposes several methods to help reach carbon neutrality, including zero-carbon standards for new buildings, making older buildings energy efficient, and installing more vehicle charging stations throughout the city.

More: *Los Angeles Times*

PG&E Found No Flaws with Tree, Poles Linked to Dixie Fire

Pacific Gas and Electric inspectors said they found no problems with the power lines, power poles or the tree linked to the ongoing Dixie Fire, according to a summary of inspection records the utility released last week.

PG&E said its crews conducted routine inspections on May 13 of the two power poles located where the fire started and found nothing wrong. The previous inspection was in December 2016. Similarly, the utility said a Jan. 14 inspection of the tree that may have sparked the fire found no problems. The tree was due to be inspected again on Sept. 21.

The company has already reported to the Public Utilities Commission that an employee spotted a "healthy green tree" leaning against a conductor on a pole on July 13, with a fire burning on the ground near the base of the tree.

More: *The Fresno Bee*

PG&E Software Issue Allowed 2019 Gas Fire to Burn Longer, Feds Say

The National Transportation Safety Board last week released the results on an investigation that found that PG&E's lack of sufficient software delayed its response to a February 2019 fire sparked by a fiber-optic contractor who struck a gas pipeline in San Francisco.

The NTSB concluded that Kilford Engineering, a contractor installing a fiber-optic conduit, failed to follow safe excavation procedures, causing a backhoe to strike a 4-inch gas pipeline and sparked a fire that engulfed a restaurant and a residence and caused more than $10 million in damage. PG&E took more than two hours to shut off gas in the area mainly because of the lack of proper software that would have helped the utility quickly find the locations of valves, according to the report. That caused a 50-minute delay in capping the gas line, the report concluded, "and increased the safety risk to the neighborhood."

More: *San Francisco Chronicle*

SCE Won't be Prosecuted for its Role in Woolsey Fire

Southern California Edison will not face criminal charges for its role in the 2018 Woolsey fire, the state Department of Justice said last week.

An investigation by fire officials determined that high winds forced a loose wire owned by SCE to make contact with conductors and sparked the fire, which killed three people and burned 100,000 acres in Los Angeles and Ventura counties. Despite that, the DOJ said based on a thorough investigation by the state attorney general's office, the Department of Forestry and Fire Protection, and the Ventura County Fire Department, officials found "insufficient evidence to establish beyond a reasonable doubt" that the utility unlawfully caused "a fire or committed any other felony violation of California law."

Officials said to press criminal charges, prosecutors would have to prove the company's equipment caused the fire and that the SCE "was aware that its actions presented a substantial and unjustifiable risk of causing a fire [and] that it ignored this risk."

More: *Los Angeles Times*

State Again Rejects Fracking Permits in Western Kern, County Sues


California Oil and Gas Supervisor Uduak-Joe Ntuk

Oil and Gas Supervisor Uduak-Joe Ntuk last week used his discretionary authority to reject a series of fracking permit applications from Aera Energy.

Ntuk sent a letter to the oil producer saying he reviewed and denied applications to hydraulically fracture 14 wells in the South Belridge oil field in western Kern County. Last month, Ntuk's agency, the Geologic Energy Management division, denied Aera's applications for 21 fracking permits in western Kern. The company has since filed a 59-page appeal of the rejections.

The county's Board of Supervisors voted 4-1 to authorize a lawsuit against Gov. Gavin Newsom over the recent permit denials, claiming he violated the state constitution in his attempt to institute an administrative ban on fracking.

More: *Bakersfield.com*, *Bakersfield.com*

ILLINOIS

Commerce Commission Opens ComEd Probe

The Commerce Commission last week voted 3-0 to open an investigation into the ComEd bribes-for-favors scandal that involved ex-House Speaker Michael Madigan.

The focus of the probe is to determine whether ComEd improperly recovered costs from ratepayers because of the scandal, which would have violated a variety of regulatory standards. The investigation was prompted by a staff recommendation that sought to see if the utility is recovering costs from its customers that are "not properly recoverable."

The recommendation also said if the investigation finds ComEd did recover costs improperly, the ICC should take the "appropriate remedial action in response to such over-recovery and the conduct which caused it."

More: *Chicago Tribune*

State Briefs

NEW MEXICO

Customers Sound Alarm over PNM-Avangrid Merger

State customers voiced their concerns last week during a virtual hearing regarding the merger between the Public Service Company of New Mexico and Avangrid, citing a bad track record of reliability and customer service.

While some politicians, environmental groups and labor unions have signed on, others say regulators need to consider Avangrid's and PNM's histories when it comes to providing reliable service in other states and parts of Latin America. Critics pointed to Avangrid's efforts to rollback provisions of a rooftop solar program in Maine, along with its millions of dollars in penalties and regulatory enforcement actions. Meanwhile, supporters say the two could drive more renewable energy development in the state.

Later in the week, New Energy Economy lawyer Tim Davis interrogated Avangrid President Robert Kump about penalties and problems with Central Maine Power. The topic arose during the second day of evidentiary hearings before the Public Regulation Commission on whether PNM should be allowed to merge with Avangrid and its parent firm, Iberdrola.

More: *The Associated Press*, *Santa Fe New Mexican*

NORTH CAROLINA

UNC-Chapel Hill's Coal Plant Air Quality Permit Renewed

The Department of Environmental Quality last week announced it renewed the University of North Carolina's Air Quality Permit for its coal-fired Cogeneration Facility on Aug. 5.

The permit draft was released in this spring, while the university was mired in litigation with the Center for Biological Diversity over its alleged violations of the Clean Air Act. The draft did not define a heat input limit. While the Clean Air Act stops this at the federal level, the state does not regulate it for the university.

More: *Indy Week*

OHIO

Judge Orders $8M Asset Freeze for Randazzo

Franklin County Judge Chris Brown last week filed an order to freeze $8 million in assets of Sam Randazzo, former chair of the Public Utilities Commission and current target of an FBI investigation, to preserve the assets for future collection.

Brown filed the order in response to a motion filed by Attorney General Dave Yost as part of a lawsuit against FirstEnergy. Yost, who sought to add Randazzo and two fired FirstEnergy executives to the lawsuit, said he would seek forfeiture of $4.3 million the company admitted paying Randazzo for his future help as chair.

More: *The Associated Press*

PENNSYLVANIA

Energy Transfer Fined for Construction Violations

The Department of Environmental Protection (DEP) last week fined Energy Transfer $140,000 for construction violations on the Beaver County natural gas pipeline.

As part of a consent order and agreement signed by the company's subsidiary, ETC Northeast Field Services, Energy Transfer agreed to put in place a plan to fix its erosion and construction issues and submit progress reports to the DEP.

Last year the agency fined Energy Transfer a record $30 million for the 2018 explosion along the Revolution Pipeline in Beaver County.

More: *The Alleghany Front*

WEST VIRGINIA

Energy Industry Vets Picked to Join Reactivated Public Energy Authority

Gov. Jim Justice last week chose two energy industry veterans, Charlie Burd and Chris Hamilton, to join the recently reactivated Public Energy Authority.

Burd, the executive director of the Gas & Oil Association of West Virginia, and Hamilton, the president of the state's coal association, will join Jeff Allen and Jeff Herholdt as the PEA's new members.

The PEA was created by Gov. Arch Moore in the late '80s to finance and construct coal plants around the state next to large contiguous coal reserves to keep costs low and to keep the mining workforce employed, according to Hamilton. The agency is empowered to promote and foster greater expansion of the state's coal and power industries, among other things.

More: *WV News*