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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: Vistra's Coffeen Power Station in downstate Illinois was retired in 2019. | *Vistra*

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In this week's issue

CAISO/West News

BOEM Issues Proposed Sale Notice for Calif. Offshore Wind Areas

By Hudson Sangree

The federal Bureau of Ocean Energy Management issued a *proposed sale notice* Thursday for five lease areas off the California coast, taking a major step toward anticipated auctions later this year and the development of the first offshore wind farms on the West Coast.

Two of the proposed lease areas in the proposed sale notice (PSN) are in the Humboldt Wind Energy Area off the coast of Northern California, near the city of Eureka. Three are in the Morro Bay Wind Energy Area off the Coast of Central California, about halfway between Los Angeles and San Francisco.

Together, the wind energy areas (WEAs) cover 583 square miles and have the potential to generate at least 4.5 GW of electricity, enough to power 1.5 million homes.

"The proposed lease areas include the entirety of the Humboldt and Morro Bay WEAs," BOEM said on its California *webpage*. "The WEAs were subdivided so that each proposed lease area is of roughly equal power generation potential and geographical size [and] is delineated in a manner to maximize energy generation."

The areas were also designed to facilitate a fair return to the federal government through competitive bidding, it said.

The lease area boundaries are based on the findings of a *study* published in April by the National Renewable Energy Laboratory that assessed the Humboldt and Morro Bay WEAs, BOEM said.

Trade groups reacted favorably Thursday to the news that BOEM has issued its PSN.

"By issuing today's proposed sales notice and staying on track for an auction in the fall, BOEM is showing that it's serious about advancing floating offshore," Adam Stern, executive director of Offshore Wind California said in a statement.

The effort will "drive economies of scale and [help to] realize the very substantial clean power, climate and jobs benefits that offshore wind can deliver for our state and the nation," Stern said.

The Business Network for Offshore Wind said the move represents a "step forward in the development of the next generation of offshore wind technology" because ocean depths off California require floating turbines, not the stationary units installed off the East Coast.

"Floating markets are advancing quickly in Asia and Europe, creating a race to develop our own capabilities and position the U.S. as a global leader in this cutting-edge market," Business Network CEO Liz Burdock said in a statement.

"The Business Network congratulates President [Joe] Biden's and [California] Governor [Gavin] Newsom's administrations for this historic moment bringing offshore wind to the world's fifth largest economy and taking necessary steps to set up a robust supply chain of domestic businesses that will elevate America as a frontrunner to an in-demand technology."

Seeking Feedback

Planning efforts for port development, transmission and other key infrastructure are underway at the California Energy Commission and CAISO. (See *California Port to Start OSW Upgrades* and *CAISO Sees $30B Need for Tx Development*.) Experts, however, have expressed concerns that those efforts could lag development plans. (See *West Coast Wind Faces Big Challenges*.)

Wind power off the coast of California will require floating platforms because of ocean depths. | *Principle Power*

At the Pacific Offshore Wind Summit in San Francisco in late March, BOEM Director Amanda Lefton said the West Coast's first offshore lease auctions would be held later this year for the Humboldt and Morro Bay WEAs. Her announcement prompted spontaneous applause from audience members, many of whom were wind developers.

"Let me be clear," Lefton said. "We are going to hold a statewide offshore wind energy lease sale in California this year. The sale will offer up wind energy areas in the northern and central coasts, and these areas will enable the buildout of significant new domestic clean energy over the next decade or more. This will also help California reach its carbon-free energy goal by 2045."

California Senate Bill 100 requires the state's utilities to supply retail customers with 100% clean energy by 2045. The state's offshore wind plans are part of the Biden administration's national goal to develop 30 GW of offshore wind by 2030.

At the summit, Lefton also announced BOEM's intent to issue a proposed sale notice, saying it would provide a "first look at the [proposed] lease terms and will ask for feedback on important initiatives for … labor agreements, credits for domestic supply chain investments, engagement with tribal nations and ocean users, and working with the commercial fishing industry."

The PSN includes a request for feedback from stakeholders within 60 days. A final sale notice (FSN) must be issued at least 30 days prior to BOEM holding lease auctions.

"The designation of final lease areas in the FSN will be informed by comments received in this PSN and other relevant data," BOEM said in its proposed sale notice.

In the meantime, BOEM is scheduled to hold the fifth *meeting* of its California Intergovernmental Renewable Energy Task Force on June 3. The "half-day virtual meeting will provide updates on offshore wind energy activities and discuss next steps in the BOEM authorization process," BOEM said. ■

CAISO/West News

CEC Postpones Vote on Offshore Wind Goals

Plans to Re-examine Targets that Critics Called Too Modest

By Hudson Sangree

Assembling floating wind turbines for the West Coast will require large port facilities, like those in Rotterdam used for Scotland's Kincardine Offshore Windfarm. | *Principle Power*

The California Energy Commission postponed its expected vote last week to establish offshore wind targets after stakeholders argued in a May 18 workshop that the commission's proposed goals of 3 GW by 2030 and 10 to 15 GW by 2045 are too conservative.

"In light of new information submitted during the workshop and public comment opportunity … [including] studies released after the draft report posted … Commissioner [Kourtney] Vaccaro will conduct a public workshop to further examine this new information to consider possible changes to the draft report recommendations for megawatt offshore wind planning goals for 2030 and 2045," a CEC statement announcing the change said.

The CEC had not posted the date of the planned workshop as of Thursday.

The *draft report* proposing the targets stemmed from last year's *Assembly Bill 525*, which required the CEC, by June 1, to "evaluate and quantify the maximum feasible capacity of offshore wind … [and to] establish megawatt offshore wind planning goals for 2030 and 2045." The effort is intended to contribute to the state's goal under Senate Bill 100 to supply all retail customers with 100% clean energy by 2045.

In written *comments* to the CEC, a group of University of California, Berkeley, scientists recommended the state set a goal of 50 GW by 2045, based on the National Renewable Energy Laboratory's (NREL) estimate that California coastal waters have a "technical potential" for 200 GW or more of offshore wind.

Technical potential is the amount of offshore wind capacity that could be developed "while taking into account exclusion factors related to water depth, mean wind speed, industry uses and environmental conflicts," NREL said in an October 2020 *report*. "By contrast, gross potential is the capacity without these exclusions." NREL estimated the state's gross potential at nearly 1,700 GW.

"Our view is that the maximum OSW capacity is significantly higher than the reference potential [of 21.8 GW] considered by the CEC, and that CEC should consider higher 2045 planning goals that reflect the updated technical-potential finding of 200 GW," the scientists wrote. "We suggest a 50 GW planning goal for 2045 … [because it] would reflect full consideration of the immense benefits to the grid of offshore wind."

Molly Croll with wind developer Avangrid Renewables said at the May 18 workshop that her company agreed with the CEC's proposed 3-GW goal by 2030 but recommended setting the 2045 goal higher at 18 to 20 GW. (See *OSW Advocates Urge California to Think Bigger.)*

Kelly Boyd, business development lead with wind developer Equinor USA, said the state's proposed target of 3 GW of offshore wind by 2030 "is a modest initial goal, especially if we want to get to 20 GW or higher at some point."

Whether the CEC can meet AB 525's requirements by June 1 is now in doubt, and the commission has not said how it expects to get around the legislature's directive. ■

CAISO/West News

BPA Weathers Early Disruptions in Western EIM

By Robert Mullin

The Bonneville Power Administration experienced two major "price excursion" events in the Western EIM within two weeks of joining the market on May 3, agency staff recounted Thursday.

"This transition [into the WEIM] has not been without trial and tribulation," Mark Symonds, BPA director of commercial operations, said during an agency workshop to discuss WEIM implementation issues.

In the first event, occurring May 8, an "external technical issue" caused the BPA's territory to separate from CAISO's WEIM for more than four hours. BPA attributed the market disruption to the expiration of a third-party software vendor's digital certificate, which prevented energy transfer schedule tags — or e-tags — from flowing into the market system.

As a result, inaccurate base schedules were submitted to the market, producing "unusual dispatches" and extremely high and low prices, Elsa Chang, BPA's EIM program manager, told stakeholders during the workshop.

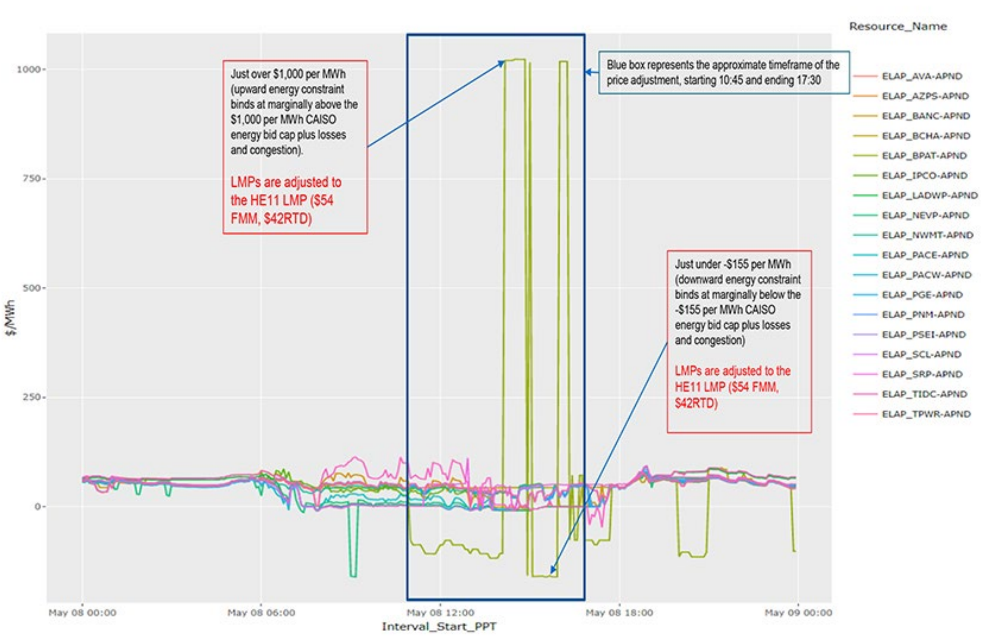
The May 8 issue started at about 9:30 a.m. PT, and WEIM prices in the BPA balancing authority area dropped deeply into negative territory taround 10:45 a.m., then rebounded to over CAISO's $1,000/MWh energy bid cap just before 2 p.m. What followed was a series of wild fluctuations between those two levels, with prices topping $1,000/MWh and then dipping below the bid floor of $155/MWh. No other adjacent BAAs participating in the WEIM experienced similar price excursions.

After prices broke $1,000/MWh, BPA isolated itself from the market at 1:50 p.m. and remained separated until 4:10 p.m., Chang said.

"Once our vendor got notified, this issue was resolved quickly," and BPA re-entered the market, she said.

Chang explained that market participants will not be billed or paid at the extreme prices that occurred during the episode. Instead, the event triggered CAISO's administrative pricing, which in this circumstance is based on the last available prices before the disruption (hour ending 11 a.m.): $54/MWh for the 15-minute market and $42/MWh for real-time deliveries.

"We had exited operationally from the dispatches in the EIM, but that does not mean that we exited from the settlement provisions, which is why the CAISO utilizes this repricing methodology consistent with their tariff," Symonds said in response to a stakeholder question. "Those prices have been established by the ISO and are flowing through the initial settlement statements received by all participating entities in the EIM."



The pattern of pricing during BPA's May 8 price excursion event | *BPA*

Donations Sought

The second price excursion event occurred May 18 after a small plane crashed near the Pacific AC Intertie, causing a curtailment of transmission schedules that cut transmission capacity for about 700 MW of BPA's scheduled generation.

The result was a temporary surplus of generation in the BPA BAA before the agency could decrease output from its resources. In the interim, BPA was compelled to increase its dispatch into the WEIM and export more power through the market, causing BPA's WEIM prices to decline to below -$500/MWh for three five-minute intervals.

Symonds said a final verdict on the extreme negative prices was still pending in CAISO's price validation process.

"There are multiple reasons for which CAISO can and does routinely make price corrections. … At last check, they had not yet made their determination on this [event], and this particular trade date has not yet been settled," he said.

Symonds cited both events in an appeal for regional stakeholders to "donate" unused transmission capacity to the WEIM to facilitate more transfers into and out of the BPA system, which will help avoid further price excursions. While BPA's prices have tracked with those of other WEIM participants, "we appreciate that additional transmission can always help," he said.

Symonds said also that additional transmission donations could assist with the more challenging conditions expected this summer.

"When there are high load events, particularly in the south, for example, there may be benefits of additional export capability to bring Northwest generation down to California, or in other events where we may be seeking to find additional loads for generation out of the Northwest, it can be helpful to also have export capability," he said.

On the flip side, referring to the record-smashing heat wave the Northwest experienced in June 2021, Symonds said, "It would be good to have that import capability as well." ■

CAISO/West News

CAISO Tackles EDAM Design in Stakeholder Meeting

Key Topics Include Resource Sufficiency and Transmission Commitment

By Hudson Sangree

Transmission commitments in the EDAM design are proving problematic. | *© RTO Insider LLC*

CAISO convened two days of stakeholder meetings last week to discuss its straw proposal for adding an extended day-ahead market (EDAM) to the real-time Western Energy Imbalance Market — an effort that could bring more of the West under the ISO's umbrella without forming a Western RTO.

The ISO fast-tracked the *EDAM initiative* last fall following a monthslong hiatus. Three stakeholder working groups met from January through mid-March to offer input on important design elements, and CAISO incorporated the groups' results into the EDAM straw proposal. (See *CAISO Issues EDAM Straw Proposal for the West*.)

Mark Rothleder, CAISO | *CAISO*

"In the first three months of this year, we convened working groups at an expeditious — some would say 'crazy' — pace," CAISO COO Mark Rothleder said, opening the two-day meeting Wednesday. "Nonetheless, we listened and processed the information that we heard to develop the straw proposal on schedule on April 28."

"Today, we are here to discuss the straw proposal," Rothleder said. "We are also here to listen and receive initial feedback from you all on the straw proposal. We know the straw proposal is not the final proposal.

"I'm expecting you will come out of here maybe a little bit disappointed that there's not more detail, maybe wanting more," he said. "I think that's OK. This is a longer process. We will be going through several iterations, and we can't go through all the details today. So, I just wanted to make sure that our expectations are set."

Panel discussions May 24 involved the EDAM's proposed resource sufficiency rules and transmission commitments, two of the more contentious issues in the process.

Resource Sufficiency

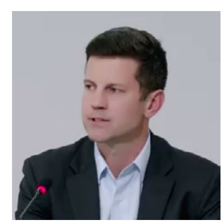
The EDAM straw proposal would require participants to pass a day-ahead resource sufficiency evaluation (RSE) to show they have enough supply to meet internal demand and reserve requirements to avoid "leaning" on the market for additional supply. Failure to pass the RSE could lead to transfer limits or an opportunity for the entity to cure the deficiency through residual supply for a fee.

Jim Baggs, regulation and market development officer for Seattle City Light, moderated a panel on resource sufficiency. He asked panelists why resource sufficiency is so important in EDAM design.

Mike Wilding, PacifiCorp | *CAISO*

Mike Wilding, vice president of energy supply management at PacifiCorp, answered that "at the risk of being Captain Obvious up here, if we're all going to go in this together — if we're going to go into the EDAM footprint together — we have to have confidence that each of us has the ability to serve our load, and that if any single [balancing authority] gets in trouble, that that does not cascade to the rest of us."

Jeff Spires, director of power at Powerex, said reliability remains the top priority in the West, and that much of that effort is now focused on the work of the Western Power Pool to develop its Western Resource Adequacy Program (WRAP). (See *NWPP Rebrands as Western Power Pool*.)



Jeff Spires, Powerex | *CAISO*

"One of the areas of concern that we have when we're looking at EDAM and market design is whether the design can be compatible with the WRAP program," Spires said.

Many EDAM participants are likely to be WRAP participants too, but it is unknown if WRAP's resource adequacy construct and CAISO's RSE requirements will be compatible, he said.

"That's inherently a difficult place to start from for a market design because we are, in effect, combining two different RA programs," Spires said, adding, "Our concern is, will the rules be designed in a way that complements WRAP or not?"

Scott Ranzal, director of portfolio management with Pacific Gas and Electric, agreed that bridging gaps between the WRAP and EDAM

CAISO/West News

Scott Ranzal, PG&E | *CAISO*

processes is important but said the EDAM's proposed "resource sufficiency test is a critical step in order to actually achieve a successful operating paradigm and provide reliable service. I've heard no argument in this room about anybody in here saying they don't want reliable service. The question becomes, how do we get to that, and how do we define it?"

Reliability is "not an easy task," Ranzal said. "No argument there. But there's plenty of really smart people here working on this problem. I do think that while it has challenges, it is a solvable problem."

Transmission Commitment

Making sure transmission is available for EDAM transfers is one of the more difficult issues facing the program's designers. The straw proposal offers alternative proposed approaches, which still must be weighed by stakeholders and agreed upon.

"Before the day-ahead market run, each EDAM entity will identify the transmission that may be available to the day-ahead market to support transfers between EDAM entities across the EDAM footprint," the straw proposal says.

But how to go about it?

The CAISO working group on transmission grouped transmission into three "buckets" to "define how entities can make transmission capacity available for transfers." Its work was incorporated into the straw proposal:

- Bucket 1 is transmission required to support resource sufficiency. It consists of "transmission rights held by transmission customers of the EDAM entity or another transmission service provider within the EDAM [balancing authority area] that have contractual agreements for energy or capacity transfers for RSE accounting purposes in the day-ahead timeframe," the straw proposal says. "These transmission rights holders must make Bucket 1 transmission available to the market because it is needed to support resource sufficiency plans across an intertie with an adjoining EDAM BAA."
- Bucket 2 consists of "transmission rights held by transmission customers of the EDAM entity or another transmission service provider within the EDAM BAA that are not associated with contractual obligations used to demonstrate resource sufficiency," it says. "This transmission has already been sold similarly to bucket 1 transmission, but the transmission rights holder can voluntarily make it available to the EDAM in return for transfer revenue. To ensure reliable transfers, Bucket 2 transmission must be firm or conditional firm."
- Bucket 3 transmission consists of "unsold firm available transfer capability (ATC) offered by the EDAM entity, in its transmission service provider function, to support transfers at interfaces between EDAM BAAs," the straw proposal says. "The EDAM entity would be expected to make available all remaining unsold firm ATC at an intertie with an adjoining EDAM BAA by 10 a.m. in the day-ahead market and to stop [open-access transmission tariff] sales of firm ATC at that intertie between 10 a.m. and 1 p.m. while the day-ahead market is running."

The working group focused on two approaches to make Bucket 3 transmission available to the market.

Under Approach 1, "EDAM entities would make Bucket 3 transmission available to the market for optimization at a hurdle rate (i.e., the published tariff rate)," the straw proposal says. "The hurdle rate allows the transmission provider to recover its costs of unsold transmission supporting EDAM transfers. However, including a hurdle rate in the optimization may cause pancaking of transmission hurdle rates, limiting efficient transfer and resource scheduling in the day-ahead market."

Under Approach 2, "entities would make Bucket 3 transmission available to the market hurdle-free through a reciprocity framework, similar to the [Western Energy Imbalance Market] today, to derive mutual benefits of higher volumes of EDAM transfers. There would be no compensation for the transmission usage through the market. EDAM entities would forego transmission revenues for overall efficient use of the transmission and the associated EDAM benefits."

In a panel discussion, Kevin Smith, an attorney representing the Balancing Authority of Northern California (BANC), said that as the working group members planned, "we were trying to put some structure around how transmission is going to be viewed, how it's utilized and so forth. And so, the buckets just became a simple convention."

Bucket 3, it became clear, would be a problem for EDAM.

"As we looked at this and started talking hurdle rates," Bucket 3 became the focus, Smith said.

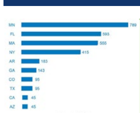
"I would personally like to put a dagger in the heart, forever, of the hurdle-rate concept, but that's just my own personal view," he said.

Kathy Anderson, senior manager of real-time operations and markets with Idaho Power, said that as the working group's discussions continued, "it became apparent that the more hurdle rates you stick in … the less economic and effective and optimized your solution becomes."

"So that kind of led to that concept of, well, how can we maybe not put a hurdle rate in there," as the group ultimately proposed in Approach 2.

Stakeholder comments on the straw proposal are due by June 16. CAISO plans to hold technical workshops on EDAM in late June and July. It also plans to post videos of the May 25-26 stakeholder meeting on the initiative's *webpage*. ■

West news from our other channels



Western States Play Catch-up on Community Solar

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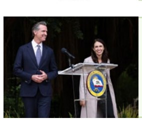

Calif., New Zealand Forge Climate Pact

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Climate Change Impacting Northwest Streamflows, Hydro Planning

BPA Expects Wetter Winters and Springs, Drier Summers

By Robert Mullin

Climate change will have a mixed impact on hydroelectric output in the Pacific Northwest, resulting in wetter winters and springs and drier summers, according to the Bonneville Power Administration.

The changing weather patterns are altering the way the federal power marketing agency plans for the future, prompting it to shorten its look-back period for developing long-term forecasts, Erik Pytlak, BPA's lead meteorologist, said last week.

"BPA has been looking at climate change for over a decade now, and we have been anticipating for some time that, as the climate continued to gradually warm, what would start happening eventually is it would start impacting our streamflows," Pytlak said during a WECC summer readiness workshop May 24.

The agency has performed two studies showing that — unlike in the Southwest — the Pacific Northwest will not experience a decrease in streamflow volumes if climate change continues.

"The entire WECC tends to get lumped in as the same climate response, and that's just not the case. … We have a very varied climate in the West, and so with climate change the responses are going to be different as well as you go from north to south," Pytlak said.

Pytlak pointed out that the PRISM Climate Group at Oregon State University, which updates its 30-year weather data set every 10 years, recently dropped the relatively cool 1980s and added the warmer 2010s. The group's data shows that much of the country has warmed 0.5 degrees to 1.5 degrees Fahrenheit in the last 10 years.

PRISM data also indicates that the Northwest's "precipitation signal" has been different from the rest of the West.

"In the last 10 years or so, while the Southwest on an annual basis has gotten drier, the Pacific Northwest has actually gotten a little wetter. And in the key snowpack areas, it is actually notably wetter, particularly in the Cascades of Washington, parts of Montana and British Columbia," Pytlak said.

Joint climate models produced by BPA, the U.S. Army Corps of Engineers and the federal Bureau of Reclamation show winters in the Northwest getting wetter over the next 20 to 30 years, with the most increased precipitation farther north in Canada, he added.

An Era of 'Non-stationarity'

BPA predicts that the most "profound change" will be seen in the region's streamflows, with higher fall, winter and early spring flows by the 2030s, and peak runoff coming earlier in the spring. The latter assumption is based on the fact that peak spring runoff has already shifted to several days earlier since the 1980s — a "statistically significant" amount, according to Pytlak. The agency also sees the likelihood for more extreme flood events in the colder months.

BPA's The Dalles Dam | *© RTO Insider LLC*

Stream flows in June, normally a peak period in the Northwest, are likely to decline, followed by a longer period of lower summer flows as the region's already dry summers become hotter and drier and electricity use increases because of cooling demand.

"We have seen a slight decrease in summer flows that is not statistically significant yet, but it is close, and you can kind of guess that, if these [climate-driven] things continue, and that shift does continue to occur, that statistical significance will show up here relatively soon," Pytlak said.

The region's climate is now in an era of "non-stationarity," according to Pytlak, "where the past does not necessarily predict the future" with respect to weather.

In response, BPA has already adopted a shorter period-of-record for the ensemble streamflow projection runs it uses for its medium-term planning, switching from 1948-2015 to 1981-2018. It has also updated the long-term temperature data it uses to forecast loads, moving from 1970-2005 to 2005-2019.

For future long-term planning, BPA is proposing to base its stream flow assumptions for hydroelectric forecasts on only the most recent 30 years of data (1989-2018), rather than looking back over the last 90 years.

As a result, BPA planners will expect to have more generation available from December to March — a period of potentially decreasing demand caused by warmer conditions — and less available from July to September, when demand is expected to rise.

"What the most recent 30 years [of data] is starting to show, if we were to switch to that, it should help us keep up with what the climate projections are showing over the next 30 years, which is an increasing amount of water in the wintertime and early spring, which should equate to more generation. But the trade-off is a longer period of low summer flows in that July and August period, which means lower potential with generation going forward," Pytlak said. ■

Solar Supply Chain Issues Dog PNM Coal Plant Replacement Plan

By Robert Mullin

Public Service Company of New Mexico (PNM) exhausted every preferred alternative before postponing the retirement of the coal-fired San Juan Generating Station until the end of this summer, a company executive said Wednesday.

The two remaining units at the plant, located in San Juan County, N.M., had been scheduled to close June 30 before the state's Public Regulation Commission (PRC) in February approved PNM's request to extend its life by another three months to cover a projected 120-MW shortfall in summer generating capacity.

In 2019, PNM filed with the PRC to abandon its 497-MW stake in the San Juan plant, proposing to replace its output with 650 MW of solar paired with 300 MW of four-hour battery storage. With 45 MW in supplemental demand-side management, the replacement resources were expected to provide 432 MW of effective load-carrying capability. PNM contracted to have all the new resources become operational in time to meet the 2022 summer peak — before San Juan was shuttered.

"This is what we were expecting to have online by about today, and I'll be frank … none of it is here. All four developers of those solar hybrid projects failed to meet their expected commercial online dates," Nicholas Phillips, PNM director of resource planning, said Wednesday during a WECC summer readiness virtual workshop.

Phillips said developers have told PNM that supply chain disruptions are the key hurdle to advancing projects, a product of both the COVID-19 pandemic and the U.S. Department of Commerce's ongoing investigation into whether Chinese companies have been thwarting trade restrictions by dumping solar equipment into the U.S. through firms based in other Asian countries. (See *Solar Sector Braces for Tariff Probe Impact*.)

Prices for solar have risen by 50 to 100% or more since the onset of the pandemic, while battery costs have jumped by about 30 to 100%, according to Philips. Even prices for simple cycle turbines have increased by 10 to 20%, he noted.

"The supply chain disruptions are hitting all parts of the market, making equipment tough to come by," he said.

Supply issues extend to the transmission side as well, with generator interconnection timelines being pushed out because of difficulties in securing transformers and other protection-related equipment, in part because of labor shortages, Phillips said.

"We're facing labor issues here in New Mexico as well, in terms of trying to get enough contractors to actually perform work to construct the interconnection facilities to get generators interconnected on time," he said.

'Not Just a Blip'

With the shutdown of San Juan looming in June and no new resources available to replace the facility, PNM — which operates a 2,000-MW peak system — forecasted that it would face a -5.5% reserve margin over the July-September summer peak period.

Phillips said the utility explored multiple options to address the capacity shortfall. It secured a deal to purchase 40 MW from a neighboring utility, won a bid for 150 MW for June and September (but not for the more critical months of July and August) and purchased 85-MW unit-contingent energy from the Four Corners coal plant in New Mexico.

But multiple requests for proposals that PNM issued turned up no viable projects to meet the summer 2022 peak, and a utility review of existing assets for possible capacity expansion determined that none of those upgrades could be completed in time. The utility also found little liquidity in the region's forward market for electricity.

As a result, PNM decided to keep Unit 4 of San Juan operating through the summer, which will provide 327 MW of capacity and bump the utility's forecast reserve margin to 17.4% for July-August and 25% for September. The unit will run at full load over the summer period to reduce cycling, Phillips said.

"Given those purchases that we were able to make and the additional capacity that we are getting now from our existing San Juan unit for continuing its operations … we are at a pretty comfortable level," Phillips said. "You know, I'm a resource planner: I'm probably never comfortable. It's not where I want it to be; it's not where I would like to be in the future."

Beyond this summer, the future looks less certain for PNM. While the utility expects two of its original projects — totaling 350 MW of solar and 170 MW of storage — to be online by early next year, the other two are currently subject to renegotiation. Phillips said PNM has talked with a "number of different developers" to find one that could complete the projects, which it hopes to bring online by summer 2024.

Because New Mexico's clean energy rules make it impossible to further extend San Juan's life, PNM will continue to "canvass the market" in search of new clean resources, Phillips said. He thinks the supply chain issues that have delayed the utility's existing projects are "not just a blip."

"They're going to persist for a while." ■

San Juan Generating Station in San Juan County, N.M. | *Sierra Club*

ERCOT News

IMM: ERCOT Conservative Operations 'Not Compatible' with Energy-only Market

Market Report Says 'Distorted' Price Signals Threaten Resource Adequacy

By Tom Kleckner

ERCOT's Independent Market Monitor criticized the grid operator's conservative operations approach Friday, saying requiring additional operating reserves to be available in real-time runs counter to the energy-only market's design.

In its annual State of the Market *report*, Potomac Economics said the market performed competitively in 2021 but that it was concerned about an increase in reliability unit commitment (RUC) activity.

The Monitor said that pricing outcomes have become "disconnected" from actual operational conditions in a market where high scarcity prices are designed to incent future investment in lieu of capacity revenues.

"While we continue to believe that an energy-only market can be successful and adapt to changing system needs, it is not compatible with ERCOT's current conservative operational posture," the report said. "The distortion in the market's economic signals will diminish generators' expected revenues, which ultimately will threaten ERCOT's resource adequacy."

ERCOT changed its operational posture in July 2021 after a June conservation notice — previously a routine practice — raised anxiety among generators and consumers still reeling from the days-long outages during the February winter storm.

The IMM said increasing reserves substantially affected market outcomes in the second half of the year.

The changes, which set aside 6.5-7.5 GW of dispatchable reserves in real time as opposed to previous reserve levels of 3.6-5.7 GW, included:

- increased non-spinning reserve requirements;
- routine use of RUCs that included issuing instructions earlier in the day and committing more longer-lead time resources; and
- adjusting forecasts to more frequently rely on the highest load and lowest wind and solar forecasts.

The IMM estimated the higher procurement cost $300 to $400 million from mid-July to year's end.

Doug Lewin, Stoic Energy | *© RTO Insider LLC*

"The potential reliability benefits are difficult to justify based on the costs, particularly since the additional procurement is applied to all hours regardless of reliability need," the Monitor said. "The energy-only market design relies on efficient pricing that reflects the reliability needs of the system. This can increase risk for market participants if ERCOT over-commits the system and renders generation owner's decisions uneconomic."

"The IMM confirms what a lot of people have been saying for a long time: a 'conservative operating posture' is really an ill-conceived, unvetted, half-baked capacity market and adds a lot of unnecessary costs to consumers' bills," Stoic Energy President Doug Lewin, told *RTO Insider*, calling the report "extremely important."

Noting the report says ERCOT "will likely need to rely more heavily" on demand-side resources and energy storage, Lewin said, "These are two things the [Public Utility Commission] and ERCOT have done very little to advance so far."

In the report, the IMM recommends developing an uncertainty product — a two- to four-hour ancillary service deployed when uncertainty results in tight real-time conditions — "to reflect ERCOT's operating posture." It also calls for a form of capacity procurement that "augments the economic signals provided by the energy-only market and ensures the adequacy of ERCOT's resources over the long term."

"A key component to any capacity proposal is defining a reliability standard," the report said, noting that such discussions are already underway at the PUC as part of the market re-design's second phase. (See *PUC Selects Firm to Aid in ERCOT's Market Redesign*.)

IMM Director Carrie Bivens said she plans to be at the ERCOT Board of Directors meeting June 21 to discuss the report.

The Monitor also said transmission congestion in the real-time market was up 46%, resulting in $2.1 billion in costs. More than $560 million of that came during the winter storm.

It said ERCOT is increasingly limiting the flows across some network paths to maintain system stability in response to the increase in inverter-based resources. More than 7 GW of new wind and solar resources and 820 MW of energy storage resources came online in 2021, accounting for all but 730 MW of new generation. Congestion rent associated with the stability constraints more than doubled from $190 million in 2020 to $400 million last year.

According to the report, average energy prices were up six-fold last year to $167.88/MWh. Taking out the winter storm's $9,000/MWh prices — which totaled more than $59 billion during the week — average prices were $40.73/MWh, consistent with 2021's increased natural gas prices, the IMM said. Average prices in 2020 were $25.73/MWh.

Total demand for electricity increased by about 3% last year, about 1.3 GW/hour, the Monitor said. Demand in the oil-rich West Texas region was up 7.2% on average as the petroleum industry continues to recover from the COVID-19 pandemic.

The IMM said it continues to look to real-time co-optimization (RTC), which procures both energy and ancillary services every five minutes, as "the most significant change to improve the reliability and competitive performance of the ERCOT markets." The RTC project, originally projected to cost between $50 million and $55 million, was postponed last year in the storm's wake. (See "Passport Pushed Back 18 Months" *ERCOT Technical Advisory Committee Briefs: April 28, 2021*.)

The Monitor added three new recommendations this year to address inefficiencies or improve incentives affecting market performance, bringing the total of suggested market improvements to nine. ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

Stakeholders, Staff Try for Consensus on Gen Outage Approvals

ERCOT stakeholders and staff are continuing to hash out their differences and reach a consensus over the grid operator's methodology for approving and denying planned generation maintenance outages.

Staff said they will review comments from stakeholders on the maximum daily resource planned outage capacity (MDRPOC) calculation, the key feature in ERCOT's plan to evaluate outage requests. They plan to bring the revised methodology to the Board of Directors for its approval during its June 21 meeting.

In the meantime, staff agreed to hold a workshop on the MDRPOC calculation and to give the Technical Advisory Committee a chance to consolidate the three sets of comments generation members provided. They have said ERCOT's goal is to allow as much capacity and flexibility as possible for planned outages while maintaining reliability.

The complex calculation takes installed thermal resources' seasonal capacity, installed intermittent renewable resources' capacity and other available capacity, and adds them together. It then subtracts from that targeted reserve capacity, forecasted reduction from price-responsive demand and other inputs.

TAC pauses during their May meeting for a moment of silence in remembrance of the Uvalde victims. | *Swagit*

Staff said using planned outages from last year, the highest since 2019, the proposed methodology's calculated maximum outage capacity provides at least 20% additional margin for through 2026. They said the MDRPOC would require some outages to be moved earlier in the spring and later in the fall.

Woody Rickerson, ERCOT vice president of system planning and weatherization, said staff compared the calculation with what has been used in the past as an aggregate for the fleet and found the new methodology allows 10 to 15% more outages.

Woody Rickerson, ERCOT | *Swagit*

"I think that the methodology is such that there are some places that can be adjusted," he said. "If we started having a number of planned outages that can't be fit, then we can look at some of these dials."

Staff have agreed to stakeholders' request to regularly review the methodology and provide annual updates to TAC. They offered to track the number of outages denied for being over the MDRPOC but said it would be too time-consuming to post inputs used to calculate the cap, noting that the process will be automated.

"For any given point in time, we could do *ad hoc* reports," Rickerson said. "Setting up something that shows every hour for five years is a bigger project and takes more time. This whole process is meant to be adjusted."

The board in April granted staff's appeal of a revised nodal protocol revision request (NPRR1108) that gives the grid operator the authority to review, coordinate and approve or deny all planned generation maintenance outages. Stakeholders earlier rejected staff's version of the measure, unanimously approving an NPRR as amended by several joint commentators. (See *ERCOT Board of Directors Briefs: April 28, 2022*.)

Staff drafted NPRR1108 to meet the requirements of legislation passed last year in the wake of the February winter storm that led to the near collapse of the Texas Interconnection. Senate Bill 3 included a provision that the grid operator "shall review, coordinate and approve or deny requests by providers of electric generation service ... for a planned power outage during any season and for any period of time."

ERCOT's Credit Limits Align with Others

ERCOT staff told the committee that the grid operator's unsecured credit limits process aligns with those of the six other U.S. grid operators. They limit counterparties to a $50 million cap in unsecured credit, as does ERCOT, with the total amount of outstanding unsecured credit ranging from approximately $100 million to $1.75 billion. ERCOT currently has about $1.4 billion in outstanding unsecured credit.

The ERCOT board requested the information after tabling NPRR1112 in April. The revision request lowers the unsecured credit limits to $30 million and was approved by TAC in April over staff's objections. ERCOT then appealed the decision to the board.

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Director John Swainson said during the April meeting that TAC's argument "should raise a level of doubt in the board about the wisdom of proceeding" with the approach.

"We're not going there to propose anything other than providing information they wanted," ERCOT's Mark Ruane said. "If the board feels it's appropriate, we are certainly at any time willing to discuss looking at the credit rules as they currently stand."

A 2013 decision by the Commodity Futures Trading Commission exempted grid operators from some legislative provisions. It disallowed the use of unsecured credit to cover credit exposure from financial transmission rights and reduced caps on unsecured credit limits to no more than $50 million per counterparty.

TAC Vice Chair Bob Helton, with Engie North America, said he will work with ERCOT staff to ensure the committee has an advocate for its position when the issue comes up again before the board.

TAC vice chair Bob Helton, Engie | *Swagit*

Members to Work on Board Relationship

TAC's leadership is working with ERCOT staff to set up a work session, tentatively scheduled for June 14, to consolidate around new processes for interacting with the grid operator's new board.

Helton said he and Chair Clif Lange, who was absent from the TAC meeting, have had several discussions with the new board members that he termed "very positive."

"It was apparent that the board was trying to indicate they completely see the need for the stakeholder process and TAC, and that they want to take full advantage as they can … of the talent and the knowledge of the stakeholder process and TAC," Helton said. "We felt really pretty good about that coming out of" the meetings.

He said there is no plan to have the committee report to the board's new Reliability and Markets committee, but that TAC will need to decide how it communicates with both the full board and the new committee. TAC members also plan to review the appeals process at the board and develop a way to consider revision requests requested by the Public Utility Commission on a separate track, Helton said.

The board wants TAC to comprise members that "have the ability to make the decisions and move things forward," he said, "rather than having to take things back to their company all the time."

"You don't need to be an officer of the company," Helton said, referring to an issue first raised last summer. (See *ERCOT Technical Advisory Committee Briefs: July 28, 2021*.)

Helton and Lange plan to take the work session's results back to the full TAC for its June 29 meeting. They face a July 11 deadline to get their information back to the board.

$1.2M to be Uplifted to Market

Staff told the committee that more than $1.2 million in nonemergency short pays from the 2021 winter storm won't be covered by securitization and will have to be recovered by an uplift to the market. ERCOT was to begin invoicing the funds on Friday and will begin distributing the funds to short-paid entities during the next several weeks.

Retailer Entrust Energy, which went into bankruptcy last year, owes the bulk of the $1.2 million.

ERCOT issued a *market notice* May 20 with the estimated cumulative aggregate short-paid amount at $2.3 billion. Much of that is owed by Brazos Electric Power Cooperative, currently in bankruptcy proceedings over the nearly $1.9 billion it owes the market.

TAC Honors Uvalde Shooting Victims

Helton asked for a moment of silence for those who died in the mass shooting the day before the meeting in Uvalde, only 160 miles away from ERCOT's Austin headquarters.

"We live in a cruel world, an unsafe world, an unforgiving world," he said. "I can't imagine as a parent going through that … having to go through the tragedy of the loss of a child."

Disconnected Load Still to be Served

The committee unanimously approved *NPRR1100*, which clarifies that a generation or energy storage resource (ESR) may serve customer load when the customer and the resource are both disconnected from the system because of a transmission or distribution outage. It is limited to configurations where the resource and customer load are using privately owned transmission and distribution infrastructure during a private microgrid island operation. The NPRR recharacterizes the load from wholesale storage (WSL) to non-WSL on an operating day basis as necessary to ensure the ESR load not eligible for WSL treatment is not provided WSL treatment.

The measure was voted on separately from the combination ballot, which also passed unanimously. The combo ballot included five other NPRRs and single changes to the Nodal Operating Guide revision (NOGRR) and the Planning Guide (PGRR):

- *NPRR1110*: modifies the black start service (BSS) confidential information, contract period and backup fuel requirements; increases the BSS procurement period from two to four years; and adds an on-site 72-hour priority fuel requirement that can be waived in whole or in part to procure a sufficient number or preferred combination of resources.
- *NPRR1119*: deletes extraneous protocol language that should have been removed as part of *NPRR978*.
- *NPRR1121*: automates the market notice used in the exceptional fuel cost submission process to notify market participants when the costs have been submitted for the operating day.
- *NPRR1129*: allows ERCOT to post on its website a list of electric service identifiers for transmission-voltage customer opt-outs from the securitization of $2.1 billion for load-serving entities' extraordinary costs incurred during the 2021 winter storm.
- *NPRR1130*: extends the sunset date for weatherization inspection fees from Sept. 1, 2022, to July 31, 2023.
- *NOGRR240*: establishes frequency and voltage ride-through requirements for new DC ties interconnecting with ERCOT after Jan. 1, 2021, and the ties that will be modified.
- *PGRR100*: revises the annual planning model base case update frequency from triannual to biannual, aligning it with the Steady-State Working Group's plan to adjust its current case-building schedule to a biannual basis.

The ballot's passage also approved the Large Flexible Load Task Force's *charter* and leadership. Bill Blevins, ERCOT director of grid coordination, will chair the group, and consultant Bob Wittmeyer, who primarily represents municipalities and cooperatives, will serve as vice chair.

The task force is developing policy recommendations for integrating large flexible loads into the ERCOT system. It met May 24 to discuss interconnection issues and divvy up work assignments. ■

— Tom Kleckner

Overheard at Grid Enhancing Technologies Summit

Clements: GETs 'Top of Mind' at FERC

By Tom Kleckner

DALLAS — Grid-enhancing technologies (GETs) took center stage last week at a WATT Coalition summit on ways to wring efficiencies out of existing transmission facilities. Held in conjunction with the May 23-25 Distributech/PowerGen International Tradeshow, the summit laid out actions utilities can take to optimize the existing grid and transition to a decarbonized economy.

"Grid-enhancing technologies could save U.S. energy customers billions of dollars every year," WATT (Working for Advanced Transmission Technologies) Coalition Executive Director Rob Gramlich said, setting the tone. "Grids in Europe, Australia and South America are tapping into these benefits, but the U.S. is lagging. U.S. electricity customers pay the price for inaction on grid-enhancing technologies, and it's time to fix that."

The summit focused on three primary technologies:

- Dynamic line ratings (DLRs) that adjust ratings based on actual weather conditions, including ambient temperature and wind, in conjunction with real-time monitoring of line loading;
- Advanced power flow controls that inject voltage to increase or decrease resistance, pushing power off overloaded facilities or pulling it on to under-used facilities; and
- Topology optimization, which automatically re-routes flow around congestion while respecting reliability criteria.

FERC Commissioner Allison Clements compared GETs to the early days of VHS tapes and web search engines.

"I think we're all here because we're hopeful that this is the future we see," she said. "Everyone makes an iPhone joke, but that transition happened through a heavily regulated industry. How do we make the changes that provide for those competitive forces to take hold [on the grid]?"

Clements said GETs have been top of the mind at the commission for some time. She pointed to FERC's December ruling that requires all transmission providers to use ambient-adjusted ratings to evaluate near-term transmission service (*RM20-16*). (See *FERC Orders End to Static Tx Line Ratings*.)

FERC Commissioner Allison Clements responds during a Q&A session. | *© RTO Insider LLC*

In February, the commission also opened an inquiry on whether dynamic line ratings should be incorporated in ratings as well (AD22-5). (See *FERC Opens Inquiry on Dynamic Line Ratings*.)

Then there's FERC's April Notice of Proposed Rulemaking on regional transmission planning requiring consideration of DLRs using advanced power flow control (RM21-17). (See *FERC Issues 1st Proposal out of Transmission Proceeding*.)

"So, there's a lot of opportunities," Clements said. "But it's very far from … that more seamless platform upon which all these services could be of interest."

Incentives for GETs

Stacey Crowley, CAISO's vice president of external affairs, said the evolution of the grid has accelerated with the increasing integration of renewables.

"The operators are learning how to work in a different world," Crowley said. "We continue to look at all types of technology when we go through our transmission planning process. We've had a couple of occasions [in which] we have approved projects that were pretty simple technology, smart wires, data storage as a transmission asset and a couple other things.

"We need to see more of that. [We need] transmission owners … to see the value and find a way for that to work in our business model," she said.

"In my career, I never saw an infrastructure project I wanted to say no to," said former FERC and Texas Public Utility Commission chair Pat Wood, now CEO at Hunt Energy Network. "The nice thing about where we are now with the transition to a cleaner and more decarbonized grid is that you need plenty of … plain ol' transmission service. We need that in spades."

Wood noted that two of his successors on the PUC, Commissioners Will McAdams and Jimmy Glotfelty, have taken a keen interest in DLRs and ambient line ratings. "I'm happy to see that with this issue, which we knew about when I was at FERC, but we didn't quite know what to do with it."

Gramlich, who served with Alison Silverstein as aides to Wood at FERC, said the three often talked about carrots and sticks when discussing how to encourage changes.

ERCOT News

"We need carrots and sticks and orange sticks," Gramlich said. "It's really important to make sure that there's incentives as well as the planning requirements" because requirements can be overly prescriptive. "Who's to say where's the exact transmission facility to deploy — what technology or what time and in what degree?"

He called for action "very soon" on interconnections. "That's another area where GETs can come in."

Addressing Congestion

Participating on a panel of renewable developers discussing the cost of curtailments, Enel Green Power's Betsy Beck recalled a GETs presentation she saw almost 10 years ago. "I just remember thinking how perfectly built this technology was to deal with [curtailment and congestion] issues that we were starting to face then. [The issues have] really grown and exacerbated since then," she said.

"Seeing deployment and case studies out there … is really exciting. … These technologies could not come at a better time."

"Transmission bottlenecks can kill your project," Invenergy's Venkata Ajay Pappu said. "You have wind and solar being curtailed because of the constraints that you're seeing on the system on multiple 345-kV paths. We're talking about not just developers not being able to build and deliver the power but also future savings back to the ratepayers."

"We're now actively thinking about creative ways to meet, to make sure that we meet our renewable energy goals. It's our view that all options need to be on the table," Amazon Web Services' Craig Sundstrom said. "We are driving as much renewable energy deployment on the grid as we can to offset our load, but we also have a significant load and we are major customers. [To have] a proactive and productive discussion [with utilities] around grid modernization is something that we would welcome."

RTOs, Utilities Weigh In

Grid operator and utility representatives agreed GETs will play a key role in integrating renewable resources. The RTOs and ISOs may be generation agnostic, as SPPs Casey Cathey said, but they also follow the markets. "Obviously, the market is moving towards renewables," he said.

Enel's Betsy Beck (left) and Invenergy's Ajay Pappu wait for their panel to begin. | *© RTO Insider LLC*

Casey Cathey, SPP | *© RTO Insider LLC*

Cathey asked the audience to imagine themselves as a CEO out to improve existing assets, saying, "If you can extend the value of the transmission system that you already have, then you made a good call as a CEO."

With 14,000 wind turbines totaling 31 GW across its 14-state footprint, SPP has a lot of existing assets. A 2009 study forecast wind accounting for 40% of the RTO's fuel mix. Today, wind penetration regularly eclipses 70% and has hit as much as 90%.

"We export to MISO, but by and large, a lot of our renewables sink within us," Cathey said.

"When you see 100 [GW in the interconnection queue], that's actually pushing the bounds a bit. There's a massive amount of benefit" with GETS.

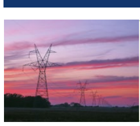
National Grid's Babak Enayati said the grid operators need to move quickly to take full advantage of GETs.

"We're going to have to adapt and adapt quickly to get everything that we want done in the next three or five years," he said.

Enayati said two roadblocks must first be resolved: the slow pace of adopting solutions and the planning process.

"The [RTOs' and ISOs'] process of adopting DLR solutions has been going slow because they have their own concerns with … upgrades and how all that data will be adopted and accepted by their operations," he said. "The other thing is the planning practice so we can quickly move towards combined solutions and merge solutions, like DLR plus power flow control. … Then we're going to see a significant shift." ■

South news from our other channels



Texas RE Knocks AEP for Communication Breakdown

NetZero Insider

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

ISO-NE News

FERC Accepts ISO-NE's MOPR Transition Plan

By Sam Mintz

FERC late Friday night accepted ISO-NE's plan to remove its minimum offer price rule after a two-year transition period, putting an end, for now, to a twisting saga that has consumed the region's policymakers in recent months (ER22-1528).

The order offered deference to the grid operator. While FERC's Democratic majority expressed disappointment that the contentious rule will remain in place for another two years, they wrote that the plan met the Federal Power Act's just-and-reasonable standard and that they had no other option but to accept it.

The outcome is a disappointment to renewable industry and environmental advocates in New England, who had hoped that the commission would step in and use its authority to order ISO-NE to immediately ditch the rule, which sets a price floor in the capacity market for state-sponsored resources.

"FERC's decision today fails to end once and for all the reign of this harmful rule," Melissa Birchard, director for clean energy and grid reform at the Acadia Center, said in a statement. "The last thing we need is more delays to decarbonization and reliable clean energy. FERC and ISO New England need to take decisive action now to show they're behind state clean energy policy. They didn't do that today."

But the commissioners' opinions in the order make clear they did not ultimately see that as an option, because the grid operator did not put it forward.

"Simply put, ISO-NE could have, and should have, done better," Chairman Richard Glick wrote in a concurrence. "Nevertheless, ISO-NE submitted a different proposal — one that delays reform of the MOPR by two years — and we must evaluate the filing before [us]."

In fact ISO-NE had been, for months, working on a proposal to immediately get rid of the MOPR, before a late pivot to the transition proposal, fueled by a group of gas generating companies in the NEPOOL stakeholder process. (See *In Late Twist, ISO-NE Calls for 2-Year Delay on MOPR Elimination*.)

The Democratic commissioners pointed to a significant silver lining from their perspective: that the rule will be gone in two years.

"Ending the federal-state antagonism over the MOPR represents a significant step forward toward ensuring resource adequacy at just and reasonable rates, which is, after all, the entire purpose of a capacity market," Glick wrote.

Writing jointly, Commissioners Allison Clements and Willie Phillips said ISO-NE's filing "sets the region on course to eliminate the MOPR, a likely unjust and unreasonable tariff mechanism that, if left uncorrected, could force customers in New England to pay millions or even billions to prop up capacity that they do not want or need."

Opponents of the transition plan have noted that it carries with it no binding commitment to actually finalize the changes to the MOPR at the end of the two-year period.

Republican Mark Christie, who joined the Democrats in supporting the proposal, wrote separately that "RTO capacity markets ... should attempt to accommodate the public policies of the states as long as the impacts, both in costs and reliability, of one or more states' public policies are not being forced onto other states not sharing those public policies."

While Christie opposed PJM's proposal to narrow its MOPR, it was in large part to the opposition of Pennsylvania and Ohio. "Here, however ... no state in ISO-NE has filed in this record opposing the MOPR's reform in ISO-NE," he said.

ISO-NE and supporters of the proposal praised FERC's decision. The grid operator said in a statement that it was "pleased that the commission saw this proposal for what it is: a reasonable step forward on New England's transition to a decarbonized future."

The New England Power Generators Association applauded the order as well. "NEPGA appreciates FERC's decision, keeping with the commission's longstanding practice of encouraging compromise solutions that reflect the geography, politics and specific needs of a given region," NEPGA President Dan Dolan said in a statement.

"I think that I'll have a celebratory drink tonight," *tweeted* Brett Kruse, a vice president at Calpine and a vocal proponent for gas generators in the NEPOOL stakeholder process.

Danly's Dissent

Republican Commissioner James Danly was the lone opponent of the proposal.

"This scheme will fail," he wrote in a dissent, which contains several exchanges dueling with Glick's concurrence. "This order will compromise reliability. All-in ratepayer costs will increase substantially."

Danly, a long-time proponent of the MOPR, wrote that "a market rate design cannot be just and reasonable if it is not competitive, and it cannot be competitive when it permits states to freely manipulate prices."

The dissent also responded to comments Glick made at a press conference after the commission's monthly open meeting May 20.

"Chairman Glick says that I am 'prone to hyperbole' when I warn that blackouts are the likely outcome of the majority's misguided policies to prop up renewables at the expense of competitive markets and existing fossil resources," he wrote. (See *Summer Forecasts Spark Warnings of 'Reliability Crisis' at FERC*.) "Chairman Glick appears to be confusing 'hyperbole' with 'reality.' California and Texas have already experienced blackouts. Over two-thirds of the nation faces 'elevated [reliability] risk' this summer. I prefer a policy correction before we have more blackouts. Today's order makes blackouts in New England, and their grave attendant consequences, far more likely." ■

The Mystic Generating Station in Everett, Mass.. | *Fletcher6, CC BY-SA 3.0, via Wikimedia Commons*

ISO-NE News

ISO-NE Offers up Governance Tweaks

By Sam Mintz

ISO-NE is touting several "enhancements" to its current governance practices in a recent memo to state energy officials, with minor changes intended to appease frustration that has been bubbling among the New England states in recent years.

The *memo*, published May 20 ahead of the annual New England Conference of Public Utilities Commissioners Symposium last week, lays out what the grid operator calls "targeted governance and communications enhancements."

"The changes reflect ISO New England's independent, but collaborative, role and its commitment to the clean energy transition," the RTO's Board of Directors wrote in the memo.

The grid operator is planning a public board meeting in Boston for November of this year, focusing on market issues.

The board also promises in the letter that it will continue to try to center consumers and costs in its considerations, pledging to review "existing documents to identify any additional reasonable needs for enhanced public communications with non-technical audiences" and discuss "potential actions to memorialize its current practice and commitment to considering the costs of significant ISO proposals."

ISO-NE will also explore boosting its public communication by hosting more webinars on recently completed studies and reports, the memo says.

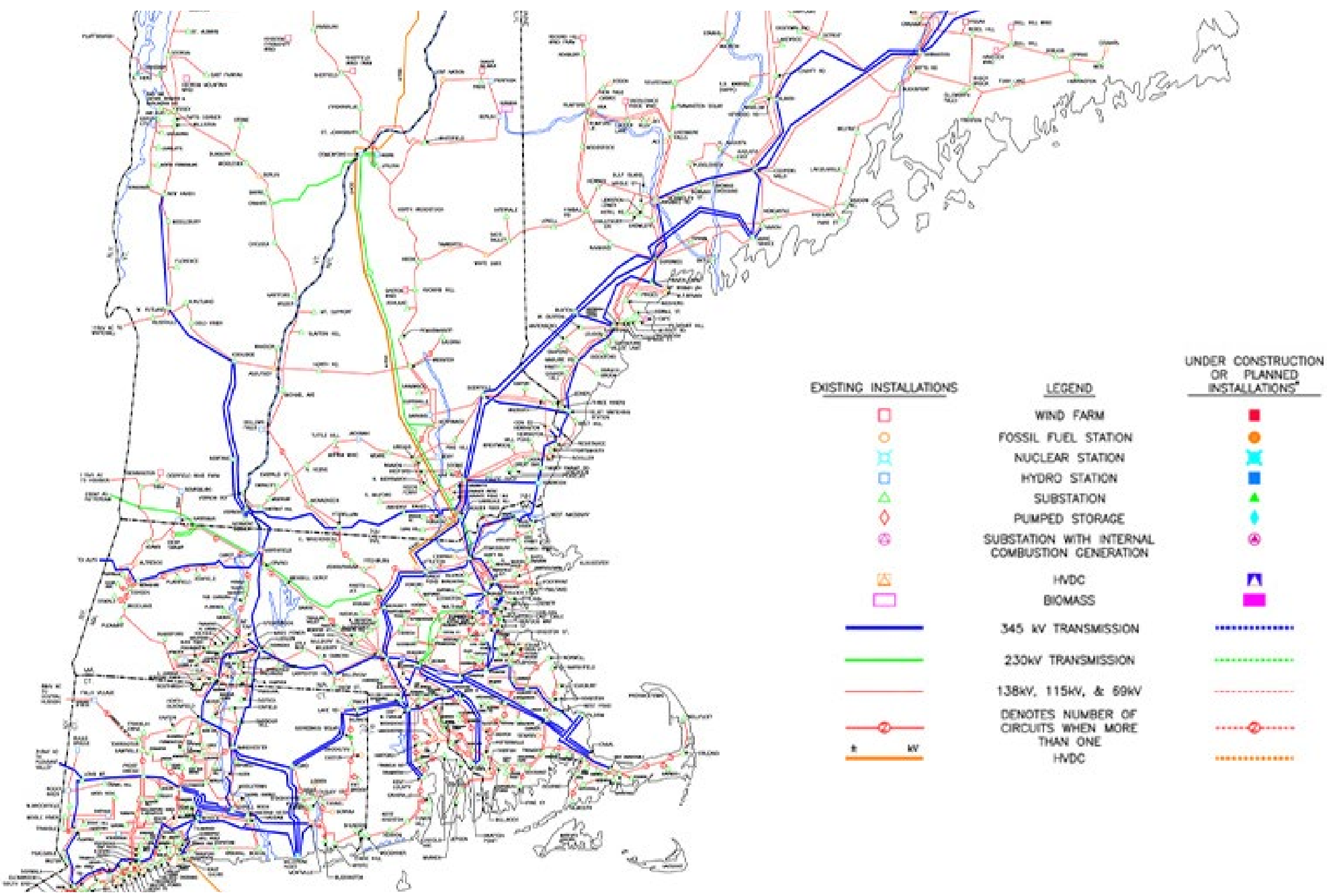
Finally, the memo says ISO-NE will try to boost its communication directly with the states by offering additional meetings. And significantly, it promises that when developing regional proposals regarding state policy, like a potential Forward Clean Energy Market, ISO-NE will "develop and propose designs that provide states with decision-making authority."

Philip Bartlett, chairman of the Maine Public Utilities Commission, told *RTO Insider* that he appreciates the grid operator's willingness to engage.

"It doesn't go as far as we've been asking for," he said, but several of the changes laid out in the memo are good steps. "We need to institutionalize these changes … and I think that's going to be a big part of the discussion going forward."

The New England State Committee on Electricity has *asked* for other changes, including more public board meetings, a standing board committee on state and consumer responsiveness, and a process for giving the states shared rights under Section 205 of the Federal Power Act when developing certain new regional rules. (See *ISO-NE, States Seek to Build on 'Alignment' Efforts*.)

Vermont Public Service Commissioner June Tierney called the memo a "promising indicator that we can work together effectively to address our regional market design challenges in the coming months." ■



The New England states have been pushing ISO-NE to make changes to its governance practices. | *ISO-NE*

ISO-NE News

RI Senate Set to Vote on 100% Renewables Bill

State Senator Wants to Send OSW Procurement Bill for Vote 'Soon'

By Jennifer Delony

The Rhode Island Senate is scheduled to vote this week on a bill that would set the state's Renewable Energy Standard (RES) to 100% by 2033.

Senate Commerce Committee members voted May 24 to send an amended version of the proposed bill (*S2274*) to the floor, striking language that would allow regulators to delay interim compliance dates based on renewables' availability.

The state updated its RES in 2016, extending a 16%-by-2019 standard to 38.5% by 2035. As amended, the bill would set annual increases in the amount of renewables state utilities must procure to reach 100% by 2033.

"The electric sector accounts for 25% of our emissions in Rhode Island, but it has an outsized importance because the key to decarbonizing our transportation and our buildings will lie in getting those sectors onto high-efficiency, renewable electric sources," Kai Salem, policy coordinator for the Green Energy Consumers Alliance, said during a webinar co-hosted by the alliance Wednesday.

Rhode Island Gov. Dan McKee signed a climate law last year that requires the state to reduce greenhouse gas emissions economy-wide 45% below 1990 levels by 2030 and 80% by 2040, and reach net-zero emissions by 2050.

Passage of a 100% RES would raise the importance of procuring more offshore wind to fulfill the standard, Salem said.

Revolution Wind, a 400-MW OSW joint venture of Ørsted and Eversource Energy, is the largest renewable energy contract in the state right now, she said, adding that "one or two more big offshore wind projects could help Rhode Island get even closer to that goal."

With the backing of McKee, Sen. Dawn Euer, chair of the Senate Environment and Agriculture Committee, introduced a bill (*S2583*) in March that would require Rhode Island Energy — formerly National Grid subsidiary Narragansett Electric — to issue a request for proposals for up to 600 MW of OSW by Aug. 15. (See related story, *PPL Completes Acquisition of Narragansett*.)

"The reason this legislation is so important is because … as offshore wind leasing has been developing in the northern Atlantic, Rhode Island has the opportunity to lead in this space by setting a really strong standard as it relates to our state's procurement goals," Euer said during the webinar.

The bill, she said, would ensure that OSW procurements are "done responsibly" by placing issues related to workforce, fisheries, environment, supply chains and marine wildlife protection into the solicitation process.

Requirements for bids, as outlined in the bill, include:

- an environmental and fisheries mitigation plan;
- a site layout plan;
- estimated economic benefits;
- a diversity, equity and inclusion plan;
- offshore wind supply chain opportunities associated with the project; and
- project labor agreement plans.

"The framework that we put together in this legislation … sets the stage for us to continue to have sustainably developed offshore wind in a way that I hope sets the tone for the region as the industry continues to grow," she said.

Ørsted Deputy Head of Market Affairs Stacy Tingley said the developer supports the bill, but it would like to see a higher procurement amount for the state.

Rhode Island Sen. Dawn Euer hopes to send a bill to authorize procurement of 600 MW of offshore wind for the state to the full Senate for a vote soon to secure passage before the end of the legislative session next month. | *Climate Jobs Rhode Island*

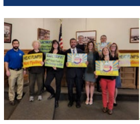
"With a larger procurement of 800 MW, to maybe 1,000 MW or more, you can really achieve economies of scale, and then it gives us some more flexibility to build out those benefits that come along with a larger procurement," Tingley said during the webinar.

In March, the Environment and Agriculture Committee held a hearing on the bill and agreed to consider it further during the current session.

"I'm hoping to be able to post the bill soon for passage," Euer said.

The legislature is scheduled to adjourn June 20. ■

Northeast news from our other channels



Climate Advocates Make Last-minute Push for NY All-electric Buildings Bill

NetZero Insider

Enviros Say It's Too Soon for Liberty's Long-term RNG Contract in Mass.

NetZero Insider

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ISO-NE News

Fears Already Mounting About Next Winter in New England

By Sam Mintz

Optimism and happy thoughts are not the dominant mood in New England right now as the energy sector starts thinking about how to prepare for next winter.

Despite dire pre-winter warnings from ISO-NE, the region sailed through the 2021/22 season without any serious emergencies or incidents, thanks to mild weather with no long stretches of extreme cold.

Six months before the air starts to chill again, the warnings are starting anew, and they could get even louder this time around.

During the New England Conference of Public Utilities Commissioners Symposium last week, speakers laid out a grim possible scenario for next winter, in which familiar fuel constraints, massive uncertainty from the war in Ukraine, and extreme weather create a dangerous, confusing situation for energy consumers.

"When we look at modeling the weather pattern of 2013/14 against today's resource mix, it comes up short. That's the thing we worry about," ISO-NE CEO Gordon van Welie said.

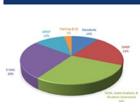
He said he's equally concerned about the coming winter as the last, with positives and negatives bouncing off each other.

The RTO's decision to prevent the Mystic Generating Station (and its LNG import abilities) from retiring, which was made three years ago and goes into effect this year, will help, he said. But hurting the region will be "massive global competition for LNG," with scarcity and prices already around $35/MMBtu.

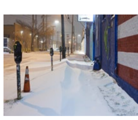
"As a region, we've tied ourselves to imported LNG. There's no quick way of getting off it," van Welie said.

A Boston street during a February 2022 blizzard | *© RTO Insider LLC*

National/Federal news from our other channels



NERC Plans Big Budget Hike for 2023



Cold Weather Standards Team Seeks Industry Support

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ISO-NE News

Pain from Ukraine

Last winter, van Welie said, the conflict between Russia and Ukraine was "just beginning to emerge."

"Russia was supplying only to meet its contracts going into last winter, so you could see the gas markets tightening up," he said.

New England is looking at an "outlier" winter this time, warned Patrick Woodcock, commissioner of the Massachusetts Department of Energy Resources.

"We really do have to look at this upcoming winter with clarity and the assessment that we don't have a rational market, but one that is completely transformed" by the war, Woodcock said.

Winter Insurance?

The one near-term solution tossed around by sector leaders at the conference last week was a one-year oil program to compensate generators to ensure that they have on-site fuel, like the *Winter Reliability Program* that was put forward for two years in the 2010s.

"I think we do need to come together as a region to think about a one-year program that would … have additional insurance for us," Woodcock said. "I think there's certainly a chance that we would not take advantage of the additional insurance. But I think at this point we have to have that conversation and do it urgently."

Craig Hallstrom, Eversource Energy's president of regional electric operations, said he thinks "we absolutely have to have a plan, insurance, to make sure this [scenario] doesn't happen."

"I don't love the Winter Reliability Program … but I accept it, because it's relatively targeted," said Doug Hurley, an energy consultant who used to represent consumer advocates and environmental groups and recently joined the firm Icetec Energy Services.

But van Welie threw cold water on the prospect of revisiting the program.

"I look at the oil program, and I think, do we want to pay oil units more money to do what they have a massive incentive to do anyway?" he said. "What's the likelihood of success of us trying to stand up a program like that, get it through the system, and have it implemented in time?"

Then there are issues of cost and regulatory uncertainty that would slow or halt its progress.

"The customer is getting hit from all angles," said Heather Takle, CEO of the energy procurement firm PowerOptions. "We're very sensitive when we talk about investments in transmission or reliability, about how are we coordinating those efforts to make sure it is the least-cost approach to those challenges?"

The reliability problems on hand are not ones that the RTO or markets can easily solve, said van Welie.

"When it comes to this winter, I just don't see any easy solution. There's a part of me that wishes I could just wave a magic wand, spring into action and … go buy the 25 Bcf it's going to take," he said. "But there are no solutions. We've painted ourselves into a corner."

'Anger and Confusion'

As energy officials worry about scenarios in which they might have to turn out the lights temporarily, the response of customers is top of mind. If New England is hit with a capacity shortage in the winter, it would manage the situation through conservation and controlled outages.

"That doesn't feel like reliability if one is a customer and your lights go out," van Welie said.

When storms roll through the region and knock down infrastructure, it's easy for customers to see why they lost power, albeit still frustrating and dangerous.

But in the case of a capacity deficiency?

"I'm not sure our customers are going to understand what's happening," said Hallstrom. "There's going to be anger and confusion, and it's going to be a tough event to manage. I don't think our customers are going to understand how we ran out of energy."

The Long Run

The longer-term view, said van Welie, is that it's clear renewables entering New England are going to lower the use of fossil fuels.

"But when we hit periods where the renewables can't produce, or when the supply chain gets constrained, we're going to end up with a peaking requirement that will have a fairly long duration. That's what we'll need to solve for," he said.

The view that risks on ISO-NE's system are large and growing isn't a universal one. Hurley said that he thinks some in New England are overplaying the winter reliability risks.

"I don't see a reason why we're less prepared this winter than we have been in prior winters," Hurley said. "And I hope we don't think of it as binary, that we have to fix the whole solution, or we can't fix any of it." ■

Siting NE's Biggest Tx Challenge, Region's Energy Leaders Say

By Sam Mintz

Massachusetts Department of Public Utilities Chair Matt Nelson (left) and FERC Commissioner Willie Phillips | *© RTO Insider LLC*

BREWSTER, Mass. — "Transmission, transmission and transmission."

Those are the top three near-term priorities of FERC Commissioner Willie Phillips, and his message was well received in New England last week, where energy regulators and officials were gathering for the New England Conference of Public Utilities Commissioners' annual Symposium.

The region's energy experts are well aware that the clean energy transition, and states' goals to add thousands of megawatts of clean energy a year, will require new wires to carry that electricity to consumers.

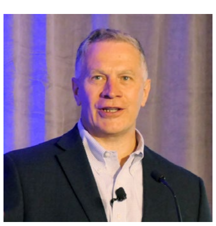
FERC is hoping to send help as they work on a Notice of Proposed Rulemaking, issued in April, that would require longer-term regional transmission planning and new cost allocation procedures for projects (*RM21-17*).

"The NOPR proposal … can help us ensure reliability of our system, and I believe it can bring costs down for our consumers, if we do it right," Phillips told the NECPUC audience.

Johannes Pfeifenberger, Brattle Group | *© RTO Insider LLC*

Johannes Pfeifenberger, an economist and principal at the Brattle Group, said the NOPR is "an opportunity to … create a tariff structure that allows more proactive, multivalue planning to come to this region."

To some of those tasked with putting up wires in New England, however, the broader planning issues aren't the main barrier.



Bill Quinlan, Eversource | *© RTO Insider LLC*

"The planning of the system I think is well in hand between [ISO-NE] and transmission owners," said Bill Quinlan, Eversource Energy's president of transmission and offshore wind projects. "We can engineer these projects; we certainly know how to finance these projects. Where most large infrastructure projects get held up is either in siting or disputes about cost allocation."

He said the rulemaking is a "very positive framework" to operate in, but that siting is the biggest hurdle.

Jared des Rosiers, Pierce Atwood | *© RTO Insider LLC*

The opposition to transmission projects has gotten both more political and more sophisticated, said Jared des Rosiers, a partner at Pierce Atwood who focuses on siting.

"These siting processes really are political campaigns. The messaging is messaging of the political process," he said. "It's not so much about the facts and the benefits of the project and what it does in terms of investments or jobs or taxes. It's soundbites or messages that attract or support or oppose different groups."

Des Rosiers also said the fact that there are now competitive solicitations for transmission projects creates new, challenging dynamics. It's no longer just "abutters or neighbors or NIMBYs" (not in my backyard) who are stepping up to challenge projects.

"We've gone to a competitive process for transmission. By its nature, that means there are winners and losers in the procurement for transmission," des Rosiers said. "Once you lose the solicitation, you may now participate in the siting process in a way that is not necessarily constructive for getting the project sited."

He called on political leaders in the region to step up their messaging efforts around building transmission and focus on the process in addition to the policy. ■

MISO News

Midwest Capacity Shortage Leads to Must-offer Talk

By Amanda Durish Cook

CARMEL, Ind. — MISO's capacity auction shortfall has nearly doubled its probability of load shed in its Midwest region over last year, prompting stakeholder calls for an expansion of must-offer requirements and sounder supply predictions ahead of the auction.

The capacity shortage will lead to a one-day-in-5.6 years loss-of-load risk (or 0.179 days/year) in the Midwest beginning June 1, instead of the targeted one-day-in-10-years (0.1 days/year) MISO reported Wednesday.

Auction results indicate a 7.7% reserve margin in the Midwest, one percentage point below the planning reserve margin MISO prescribed heading into the auction.

MISO Independent Market Monitor David Patton said he doesn't expect an increase in load shed during the 2022-23 planning year, but said next summer seems fraught. (See *MISO Exec, IMM Debate Next Steps After Capacity Auction Shortfall*.)

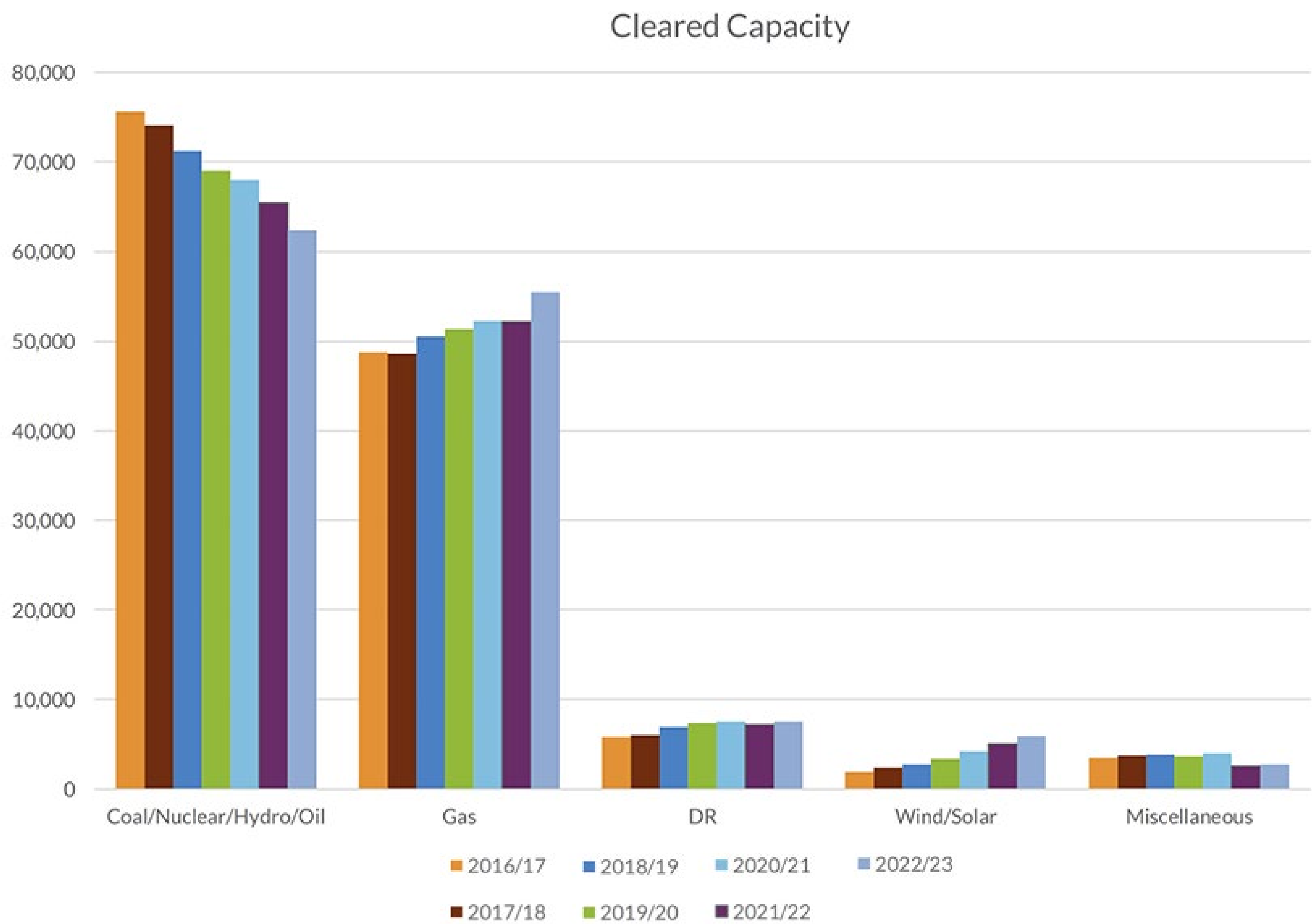
The April capacity auction cleared MISO Midwest at a $236.66/MW-day cost of new entry for generation, reflecting a 1.2-GW shortfall across the subregion. Staff have told stakeholders to prepare for the possibility of temporary, controlled load shedding over the summer months. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

MISO said its Zones 4, 5 and 6 "relied significantly on the auction" to meet resource adequacy requirements. Southern Illinois' Zone 4 needed outside resources to cover 20% of its requirements before the auction, while Zones 5 and 6 in portions of Missouri, Indiana and Kentucky needed about 15% each.

During Wednesday's Resource Adequacy Subcommittee meeting, MISO Director of Resource Adequacy Coordination Zakaria Joundi pledged future discussions with stakeholders on how the RTO can improve its public-facing and preliminary supply data before auctions.

MISO said this year's planning resource mix "shows the continuation of a multiyear trend toward less solid fuel and increased gas and nonconventional resources." It said the capacity supplied by load-modifying resources increased 4.4% planning-year-over-planning-year.

The grid operator said 21 generation resources representing 3.4 GW in the Midwest footprint choose not to participate in the voluntary auction.



MISO cleared capacity by resource type, 2016-2023 | *MISO*

MISO News

The RTO's and the Organization of MISO States' annual resource adequacy survey last year indicated 10 of the resources were deemed "high certainty" to be available for the 2022-23 planning year.

The other 11 resources were rated "low certainty." The Monitor granted all 11 auction participation exclusions.

Minnesota Public Utilities Commission staffer Hwikwom Ham asked whether MISO tried to reach out to members to ask why they chose not to offer.

Eric Thoms, senior manager of resource adequacy operations, said MISO is still parsing through auction results data and has not communicated with those resource owners.

"I think now we're trying to internalize some of the data," he said.

Ham said those energy resources that didn't offer should be considered "speculative." MISO resources that are not classified as capacity planning resources do not have a must-offer requirement.

Monitor staffer Michael Chiasson recommended that the RTO extend a must-offer requirement to energy resources. He said the Monitor's hands are tied by the MISO tariff to mitigate withholding resources that are not deemed planning resources and that it can't recommend withholding sanctions on any resources other than capacity resources.

The IMM's Taylor Martin also pointed out that MISO excludes resources with planned summers outages from auction participation.

WEC Energy Group's Chris Plante asked whether staff has considered that some unit owners are using up to three-year suspension status to maintain MISO interconnection rights so they can retire and replace generation. Plante said such unit owners might be keeping a grip on their rights and never had the intention to participate in the auction.

Stakeholders have also asked MISO to evaluate how it calculates its capacity import and export limits between the 10 local resource zones in the auction given the changing generation fleet.

The grid operator has said new intermittent resources and baseload generation retirements impact base transmission system line loadings and the ability to import and export power, in some cases reducing necessary counterflow or increasing constraints. The RTO said the "location and availability of generators to ramp up during transfer and to redispatch around identified constraints is shrinking."

MISO and stakeholders will continue dissecting the auction's results and tee up possible process changes stemming over the summer.

The RTO's plan to alter its annual capacity market into four seasonal capacity auctions with an availability-based capacity accreditation is still pending before FERC. Joundi said MISO hopes to have a decision from the commission within the next few months.

Meanwhile, staff plans to register their first energy storage resources for participation in its wholesale markets, including the capacity auction, by Sept. 1. FERC in 2020 *accepted* MISO's Order 841 compliance plan to fully incorporate electric storage resources (ER19-465).

The grid operator hopes to finalize its business practice manuals accompanying the compliance plan by July 29. Stakeholders have asked for a refresher on the RTO's market storage participation plan. ■

MISO Customers Ask for Penalty-free Load Reductions

Complaint at FERC Comes After Auction Shortfall

By Amanda Durish Cook

MISO transmission customers filed a complaint with FERC last week that the grid operator should allow its customers to reduce their load without penalty to lessen the possibility of summer blackouts.

The Coalition of MISO Transmission Customers (CMTC) said in a filing that the load reductions will help address a 1.2-GW capacity shortage following MISO's 2022-23 Planning Resource Auction for its Midwest subregion. The shortfall triggered a $236.66/MW-day cost of new generation entry clearing price for MISO Midwest. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

The RTO has said the capacity deficit might force it to order temporary, controlled load sheds this summer and it predicts insufficient firm resources to handle summer peak forecasts under typical demand. The grid operator's management has also said members must build new generation or risk future blackouts.

CMTC argued that when the capacity auction fails to procure enough supply, it should allow some load to exit the system, bolstering reliability by trimming demand while also avoiding the steep capacity prices.

The group said it has members "actively assessing the need to reduce operations" by more than 200 MW at least through May 31, 2023.

"A significant factor in the customer's operational decisions is the ability of the customer to avoid the PRA charges that it would otherwise incur," CMTC told FERC.

The group argued that MISO's tariff shouldn't regard PRA charges as "unavoidable and sunk" for load. The group said the tariff is unjust and unreasonable because it doesn't contain any options for load to leave the system when it faces threats to resource adequacy.

"Because the exit of the customer's load and possibly other loads would provide reliability benefits to MISO as MISO addresses looming resource adequacy issues in its footprint and the shortage of capacity procured in the 2022/2023 PRA, load should have an opportunity to exit the system without being charged," CMTC wrote. "MISO's tariff should be revised to enable MISO to create an orderly process in which load could nominate to exit the MISO system for the remainder of the planning year, in exchange for avoiding PRA charges, to help MISO address the insufficiency."

The group suggested that MISO could allow load exits equivalent to the 1.2-GW auction shortage and stop accepting any further load reductions once it resolves the supply and demand imbalance.

CMTC asked FERC for expedited treatment of its complaint, requesting a response no later than early July. It also said it had been in touch with MISO about its proposal before it filed the complaint. ■

Vistra's Coffeen Power Station in downstate Illinois was retired in 2019. | *Vistra*

MISO News

MISO Curbing Use of Emergency Commitment Statuses

By Amanda Durish Cook

CARMEL, Ind. — MISO said it will limit when some resources can use an emergency commitment status outside of emergency conditions, hoping to prod a more available resource fleet.

The restriction is poised to mostly affect units designated to meet the grid operator's resource adequacy requirements. Currently, such resources can use an emergency commitment status in the energy markets, making their entire output unavailable unless there's a generation emergency. The emergency commitments don't affect the resources' capacity credits. (See *MISO Moves to Restrict Emergency Commitments*.)

MISO market design adviser Dustin Grethen said the proposal will allow the RTO's operators to deploy units designated for resource adequacy requirements in anticipation of tight conditions, much like MISO's registered load-modifying resources.

"Operators are counting every megawatt when they are tracking a potential shortfall of needed capacity," Grethen said during a Resource Adequacy Subcommittee meeting Wednesday.

MISO reported that during the 2020-21 planning year, approximately 22 GW of resources used the emergency-only commitment status about 20% of the time.

Grethen said MISO will allow emergency commitment status's use under four conditions. He said the grid operator is proposing three conditions where a unit can use the status without first seeking permission from the Independent Market Monitor:

- when the unit is at its permit limit, where its top range can only be accessed in a declared emergency;
- when the unit is experiencing a "severe" energy limit, such as a fuel shortage, that keeps the unit from responding to capacity emergency conditions; or
- in situations where operating the unit would go against "good utility practice" because the unit risks damage if it operates under high temperatures, high pressure or vibrations, or leaks or cracks in equipment.

MISO is also proposing a "catch-all" condition, where a unit can use the status if it consults with and receives permission from the IMM ahead of time, or while a limiting factor is occurring.

Grethen said MISO wanted a "catch-all" category because the three conditions won't likely cover all scenarios where a unit needs to use the emergency commitment status.

Stakeholders have said that a unit sometimes uses an emergency-only status for inspections, tours, testing, quick maintenance or because of emissions limits.

MISO wants the changes enacted in time for the 2024-25 planning year. ■

MISO's May 25 Resource Adequacy Subcommittee underway | © *RTO Insider LLC*

MISO News

FERC OKs New Queue Priority for MISO, SPP Seams Studies

By Amanda Durish Cook

| *Pattern Energy*

FERC on Friday approved MISO's and SPP's plan to assign a new prioritization of projects to study in their respective interconnection queues.

The new priority will employ a "first-ready, first-served" approach in which the RTOs study the projects that are primed for interconnection first, rather than based upon the order in which they entered the queue (*ER22-1533*).

FERC said the new arrangement will provide more certainty by establishing a rank when the projects pass the queues' first decision points instead of when they submit an interconnection request (SPP) or when they pay study fees (MISO).

The commission said the queues' first decision-point deadlines are an appropriate touchstone because they're "a point in time after most delays in the interconnection study processes occur." The new priority should "reduce the possibility that lower-queued cycles or clusters will not have affected systems information from higher-queued cycles or clusters when major commercial decisions are made," FERC said.

The priority will be used for the RTOs' system impact studies, affected system studies, and cost assignments for network upgrades. The grid operators study each other's nearby IC generation projects for potential effects that might require transmission upgrades in their footprints. MISO and SPP assign network upgrades costs identified in interconnection studies based on queue priority.

The grid operators said their ongoing joint targeted interconnection queue (JTIQ) transmission planning study compelled them to reexamine queue priority to ensure higher-queued generation projects aren't holding up more prepared but lower-queued projects. (See *Midwest Energy Policy Series Addresses JTIQ Projects*.)

The new approach is effective with the 2020 cycle of MISO interconnection requests and the 2017 cluster of SPP requests.

The RTOs said their current practice "can lead to situations where interconnection customers are required to make significant commercial decisions about the viability of their projects without knowing what network upgrade costs they will be assigned after projects with higher queue priority have been studied."

EDF Renewables supported the change, saying that it is "often faced with having to execute a generator interconnection agreement 12 to 18 months prior to receiving final affected system cost responsibility."

Invenergy said the new prioritization will improve cost certainty for IC customers but said the effective date leaves out customers that entered the MISO queue in 2018 and 2019 and are still awaiting SPP study results. (See *CGA Requests MISO Help for Late-stage Interconnection Projects*.)

But FERC said the "proposed transition point appropriately respects the expectations of existing interconnection customers while improving the affected system study process for new interconnection customers." It declined Invenergy's request to include the 2018 and 2019 MISO queue cycles in the new ranking.

The change comes as MISO and SPP are proposing to do away with their affected system study process and instead conduct more frequent interregional studies like the JTIQ to get more generation online near their seams. (See *SPP, MISO Propose Scrapping Affected System Studies*.) ■

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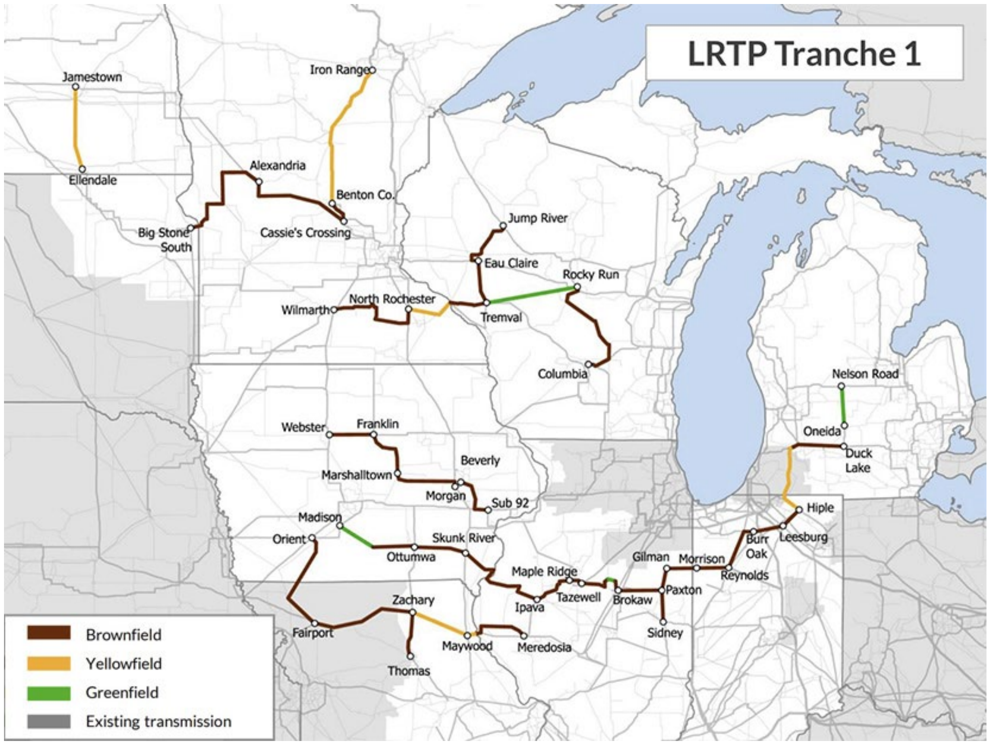
MISO News

MISO Makes Business Case on Long-range Tx Plan

Members Voting on $10B Buildout Package

By Amanda Durish Cook



MISO says 90% of the long-range portfolio will utilize existing and adjacent rights of way. | *MISO*

MISO members began an email vote last week on whether to recommend MISO's $10 billion long-range transmission plan to the Board of Directors as staff made final pitches for the project portfolio.

The members' advisory vote was originally slated to take place during a special Planning Advisory Committee (PAC) teleconference Friday, but some requested voting by email.

Voting will conclude June 6. The $10.3 billion, 345-kV package will then advance to the board's System Planning Committee for its consideration. The full board will hold a final vote on the portfolio in July.

Presenting the long-range transmission plan's (LRTP) business case to board members on Thursday, Vice President of System Planning Jennifer Curran said the plan is "critical" to MISO serving load as the footprint transitions to a new resource mix.

Curran called the initial search for long-range projects "one of the most if not the most complicated studies" MISO has ever undertaken. She said staff have been studying the transmission "in earnest" since 2020.

"That seems like a long time, but it's really quick considering the amount of transmission analysis and the magnitude of it. … It's been a lot in a short amount of time," she said.

Curran said the package is MISO's "least-regrets" assembly of projects based on a "conservative view" of members' clean energy and decarbonization goals. She said staff will soon begin studying the LRTP's second phase of possible projects "because the world continues to change aggressively." That portfolio will contemplate a more rapid resource evolution and could yield projects with higher voltages than 345 kV.

MISO plans to continue monthly stakeholder workshops to discuss the second batch of LRTP solutions.

The RTO said its first portfolio will mitigate future excessive loading on existing lines and prevent possible voltage collapse across the Midwest. It anticipates the LRTP portfolio will yield anywhere from $23 billion to about $52 billion in financial benefits over 20 to 40 years of the projects, a 2.6:1 overall benefit-to-cost ratio. The grid operator estimates Midwestern cost-allocation zones will see cost-to-benefit ratios ranging from 2.1:1 to 3.2:1.

During the PAC teleconference, Clean Grid Alliance's Natalie McIntire said MISO's benefit estimates are cautious and said there are likely more unquantified benefits, especially reliability improvements.

The RTO has reduced the portfolio's costs to $10.32 billion from $10.38 billion. It expects the 20- to 40-year present value of the projects' total revenue requirement to range from $14.2 billion to $16.9 billion.

"Some of the projects increased in cost, some decreased in cost," Jarred Miland, senior manager of transmission planning coordination, said. He said the portfolio is targeted to be in service by 2030, but that final in-service dates and costs are still subject to change.

MISO's Joe Reddoch said staff will monitor long-term inflation trends and update cost projects if inflation materially affects construction costs.

Making Use of Existing Routes

Aubrey Johnson, the grid operator's vice president of system planning and competitive transmission, said about 90% of the first LRTP portfolio will use existing and adjacent rights of way, or "yellow fields." He said the planning team paid careful attention to where transmission lines could use existing rights of way.

"We think this will be a significant contributor to the speed of the regulatory process," he said.

Director Nancy Lange, a former Minnesota commissioner, asked whether MISO expects any of the projects to be delayed or rejected by state regulators.

Johnson said though all state regulatory processes are different, using existing transmission routes should maximize the projects' prospects.

MISO President Clair Moeller said states realized that the grid operator's last long-range transmission projects in 2011 worked as a portfolio and were "quite responsive" to the proposal. He acknowledged that the Cardinal-Hickory Creek line remains in legal limbo a decade later over a planned river crossing route in Wisconsin. (See *Enviro Groups Push Wisc. DNR to Scrutinize Cardinal-Hickory Creek Line*.)

However, Minnesota Public Utilities Commission staffer Hwikwon Ham warned during an

MISO News

earlier Market Subcommittee meeting last week that the first LRTP portfolio could temporarily increase the already high congestion levels because construction will be carried out very close to existing lines in the footprint.

OMS Hears Different Benefits Perspective

The Organization of MISO States recently hired an engineering firm to conduct an independent review of the LRTP, which the firm called a "comprehensive assessment."

RLC Engineering's Rick Conant said during an April OMS board meeting that the first cycle of projects doesn't resolve all of MISO's overloading issues. He said more thermal fixes would likely arrive with the second cycle of long-range projects.

However, RLC said it arrived at a 1.4:1 B/C ratio for the first group of projects, smaller than MISO's overall projection of 2.6:1. The firm's Waine Whittier said despite the findings, the projects still are beneficial to pursue.

OMS has not made the RLC study public, though its members have discussed the results in open meetings.

Competitive Bidding Question Remains Open

MISO will release a draft list of long-range facilities that will be considered for competitive bidding by June 1. Johnson said staff are still analyzing "the competitive landscape."

Also last week, the RTO made a FERC filing to change its competitive transmission process to exclude "short segments and conductor-only" work from competitive bidding eligibility (*ER22-1955*). Brian Pedersen, senior manager of competitive transmission administration, said some smaller projects will be necessary to accommodate the long-range projects and "are not best suited for competition."

Some members said they were taken by surprise that MISO would file the tariff changes without first consulting the stakeholder community. ■

MISO's benefit estimates for the first cycle of its long-range transmission plan | *MISO*

MISO News

MISO to Limit Market Error Resettlement Times

By Amanda Durish Cook

MISO intends to adjust the time it allows itself to retroactively correct market-pricing errors, stakeholders learned during a Market Subcommittee meeting Thursday.

The RTO's markets can experience two types of pricing errors: implementation errors and continuing errors. Market-implementation errors are meant to be remedied near the operating day, with corrections made in time to be used in settlements. Continuing errors, on the other hand, are those discovered after settlement and could require up to two years of resettlements "from the date of MISO's formal acknowledgement."

MISO will seek FERC permission to impose a two-week limit on implementation errors and a one-year resettlement timeframe for continuing errors that begins ticking when the grid operator acknowledges the error in writing. Staff's Daric Moenter said the RTO intends to file tariff changes in the third quarter for commission approval.

Under the proposal, implementation errors will be "identified, investigated and corrected" within two weeks. If they're not discovered in time to be remedied within the two-week window, they will be subject to corrective settlements through the continuing error process, provided the pricing error meets a threshold of $100,000 or 0.5% of gross market activity per affected operating day.

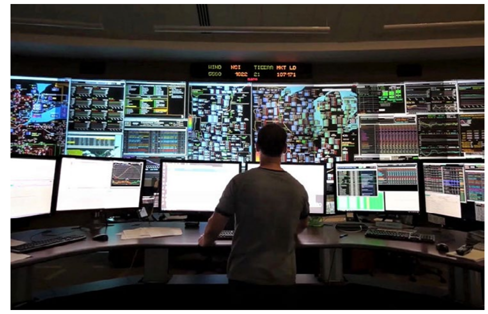
"The recommended changes ensure that price accuracy is as important as certainty and permanency," Moenter said.

Laura Rauch, senior director of transmission planning, said MISO is trying to strike a balance between correcting significant pricing errors and not spending "thousands to chase pennies."

As an example, she said it would take millions of dollars of staff hours to make corrections two years back in addressing a daily settlement error.

Moenter said staff hope to avoid spending "an ordinate amount of staff time" on insignificant pricing errors. He said going back two years to reprice errors in the day-ahead and real-time systems can quickly become burdensome.

WPPI Energy's Valy Goepfrich said she didn't see any problems with the existing repricing policy and said she didn't understand why MISO proposed the changes.


MISO control room | *MISO*

Stakeholders have said that during messy weather events, MISO employees probably don't have time within the two weeks to review pricing and apply substitution logic to correct errors before they're settled.

"Everything isn't always clean and tidy here, and we've seen that," Xcel Energy's Kari Hassler pointed out in April.

Moenter asked for stakeholder feedback on the repricing proposal through June 10. ■

NYISO Management Committee Briefs

Joint Board/MC Resumes In-person

Following two years of remote meetings during the COVID-19 pandemic, the NYISO Board of Directors will resume in-person interactions with the Management Committee at their annual joint meeting scheduled for June 13, CEO Rich Dewey told the MC on Wednesday.

"This is really an important meeting for our Board of Directors to hear directly from market participants what the key concerns are; what their issues are," Dewey said.

Discussion will focus on the ISO's Grid in Transition initiative and what specific challenges market participants are encountering, Dewey said.

While many market participants have expressed intent to attend the event at the Sagamore Hotel on Lake George, COVID infection rates continue to be high in the capital region and New York state generally, so the ISO has procured a larger space than usual to allow for greater distance among participants and is planning most social activities for outdoors, he said.

"We're going to send out some information encouraging people not to attend if they're experiencing any symptoms and just be smart about taking care of themselves and each other as we get ready for an event like this," Dewey said. "We do recognize that there are some individuals who might want to participate remotely, and we're looking at how we might be able to accommodate that."

Dewey closed his report with a reference to the March MC meeting, where he had briefed the participants on the ISO managing some atypically high staff vacancy rates. (See "Staffing Recruitment Improves," *NYISO Management Committee Briefs: March 30, 2022*.)

"We've had two good recruiting months in a row, and we've been able to identify some really top talent that we brought into the organization, so the vacancy rate is down in the range of 9%, which is still a little bit higher than our budget, but we do have a healthy queue of individuals we plan to onboard in the next month," Dewey said. "At least from a recruiting standpoint, things are trending in the right direction."

Adequate Capacity for 2022 Summer

NYISO foresees having adequate generating capacity margins for normal weather conditions this summer, without emergency operating actions, but it would require emergency operating actions to varying degrees depending on the severity of extreme weather conditions, Vice President of Operations Aaron Markham *reported*.

"From a statewide perspective, we expect a surplus of about 2,000 MW for a baseline forecast without operating emergency operating actions, and that dwindles to an approximately 2,300-MW shortfall when we go all the way to the extreme 99-1 [once in 100 years] forecast conditions," Markham said in presenting the Summer 2022 Capacity Assessment.

Last winter the ISO started including a 99-1 extreme forecast in its capacity assessment and plans to continue to do so to advise stakeholders of what that looks like, he said.

"We do have approximately 3,300 MW of emergency [resources], so when we take into account those, we do show positive margin for all of forecast conditions even up to 99-1 on a statewide basis," Markham said.

Projected capacity margins for normal and extreme weather conditions without emergency operating actions:

- 1,918-MW capacity margin for 50-50 peak forecast conditions
- -382-MW capacity margin for 90-10 peak forecast conditions
- -2,287-MW capacity margin for 99-1 peak forecast conditions

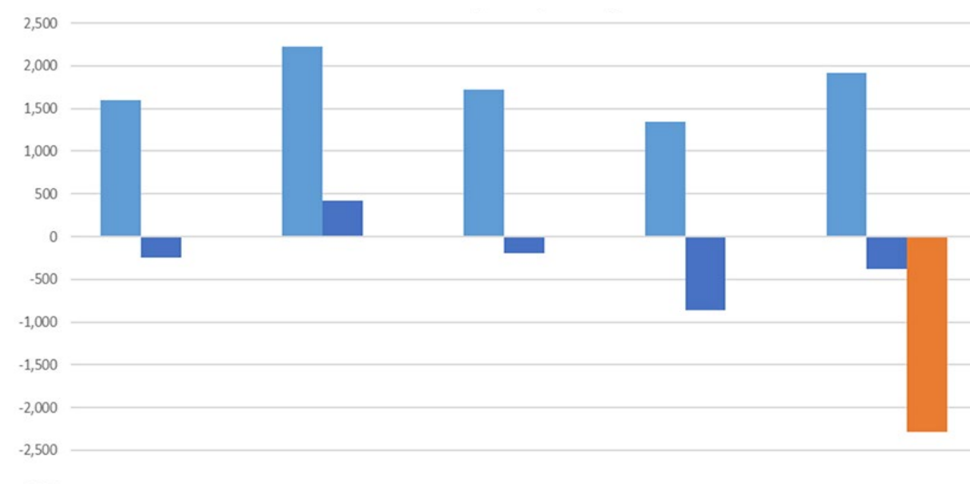
Projected capacity margins for normal and extreme weather conditions with up to 3,294 MW of emergency operating actions:

- 5,212-MW capacity margin for 50-50 peak forecast conditions
- 2,912-MW capacity margin for 90-10 peak forecast conditions
- 1,007-MW capacity margin for 99-1 peak forecast conditions

The ISO is continuing to monitor energy supplies and prices based on global markets and events, and the weekly fuel survey process indicates that the prices for fuel will be higher this summer than in recent history, Markham said. Oil inventories for dual-fuel-capable units are lower than last year but still sufficient for starting the summer.

"We've done our normal coordination with the transmission and generator maintenance outages to ensure that, to the extent possible, any outages scheduled over the summer can be recalled on short notice to make sure that the resources are available to meet hot weather needs," Markham said. ■

— Michael Kuser



	2018	2019	2020	2021	2022
50/50	1,599	2,227	1,721	1,344	1,918
90/10	-241	423	-194	-860	-382
99/1					-2,287

Projected capacity margins for normal and extreme weather conditions without emergency operating actions include 1,918 MW for 50-50 peak forecast conditions; -382 MW for 90-10; and -2,287 MW for 99-1 peak forecast conditions. | *NYISO*

NYISO Monitor Proposes Capacity Pricing Overhaul

State of the Market Report Finds Need for Better Price Signals, Generator Compensation

By Michael Kuser

NYISO's Market Monitoring Unit is recommending a new capacity market pricing structure that it says would lower costs and improve incentives for market participants making long-term investments.

Presenting *highlights* of the Monitor's 2021 State of the Market *Report* to the Management Committee on Wednesday, Potomac Economics' Pallas LeeVanSchaick said that the current processes for setting the installed reserve margin (IRM) and locational capacity requirement (LCR) "aren't well coordinated with each other."

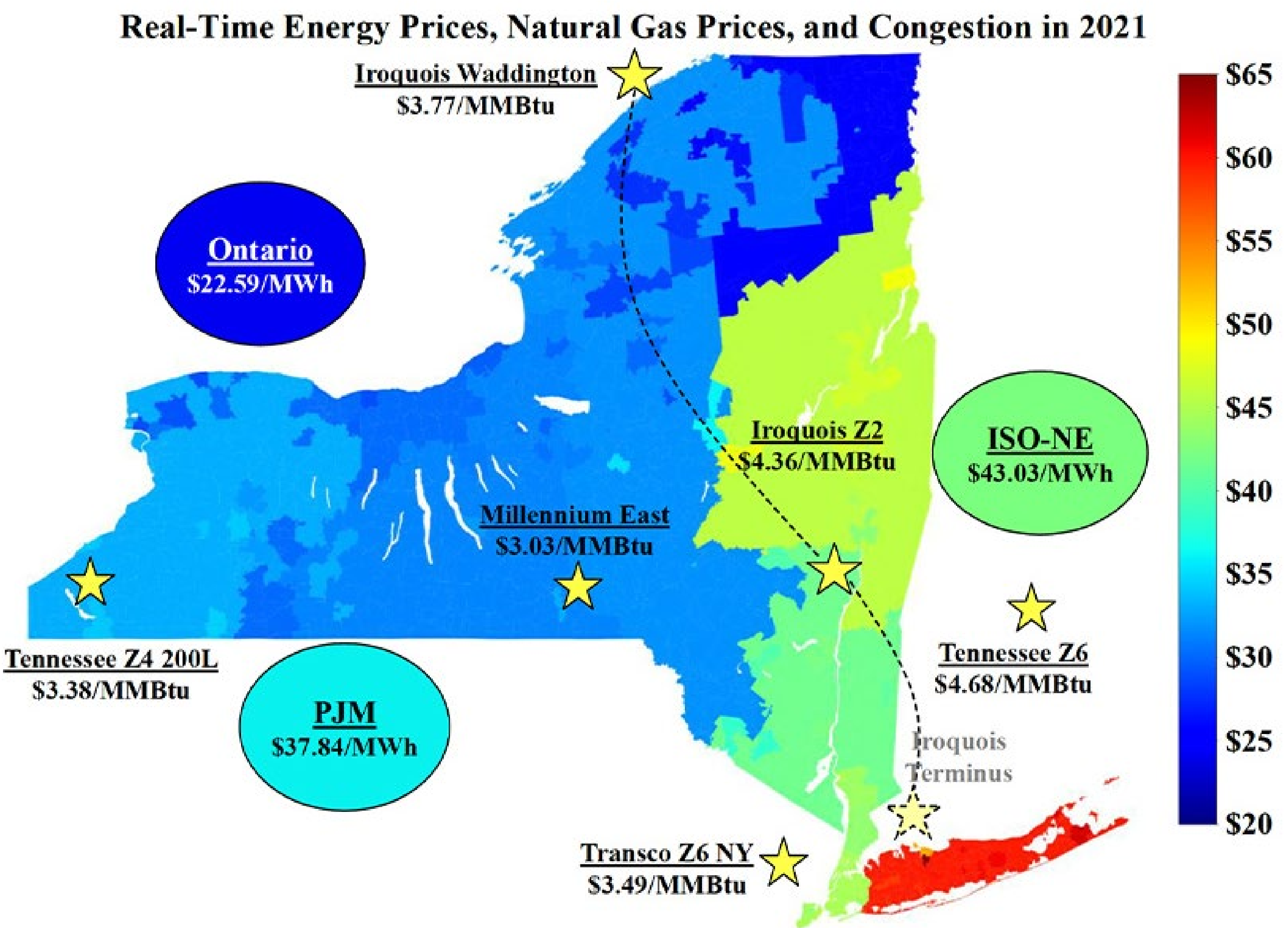
"It is not possible for the NYISO to address the concerns discussed above in a piecemeal fashion," the report says.

It proposes to institute an overhauled capacity market pricing structure, dubbed locational marginal pricing of capacity (C-LMP).

The market has just four fixed pricing regions, so when transmission constraints arise within one, it can lead to inefficient results. For example, in recent years the Monitor has observed bottlenecks going into Western New York capacity zones from Central New York zones, and from Staten Island into the rest of New York City, that are not represented by the current capacity zone configuration, the report said.

"We've seen that the lack of a treatment of constraints upstate has accentuated some of the fluctuations in the IRM and LCRs," LeeVanSchaick said. In addition, "the LCR optimizer has a flawed objective function. ... It's not only that it doesn't find an efficient solution; it's also problematic because there are aspects of it [overly sensitive to small changes in inputs] that contribute to more volatility in the requirements."

These constraints can be a barrier to entry for new resources, which are required to pay for transmission upgrades to receive capacity rights if they are not fully deliverable throughout their entire capacity region. Offshore wind and battery projects in Long Island



The LCR optimizer has a flawed objective function and is overly sensitive to small changes in inputs, which contributes to more volatility in the requirements. | *Potomac Economics*

NYISO News

were recently assigned costly deliverability upgrades that are not required of incumbents that are limited by the same constraints, the report said.

The report says C-LMP would:

- "produce more granular prices that are better aligned with NYISO's planning criteria;
- be more adaptable to changes in resource mix and transmission flows;
- remove unnecessary barriers to new entry in the interconnection process;
- be less burdensome for the ISO to administer; and
- reduce the overall costs of maintaining reliability."

"There are some emerging concerns that we see with potential new entry and retirements," LeeVanSchaick said. "On the new entry side, of course, it's a lot of intermittent renewables that are principally motivated by [renewable energy credit] solicitations, and on the potential retirement side you have of course Indian Point 3 in 2021. But then you've also got a number of dual-fuel peaking units leaving as well through 2025."

Price Trends

LeeVanSchaick also discussed pricing trends over the last few years. Gas prices are clearly driving energy prices, but they are not the single biggest factor, he said.

"We saw a big increase from 2020 to 2021, not only [because of] gas prices but certainly the Indian Point nuke retirements that are ongoing," LeeVanSchaick said. "Between those two years it certainly is contributing to the higher prices in Eastern New York. We [also] saw more planned and forced transmission outages in 2021." Last year also saw extra high levels of forced transmission outages into Long Island.

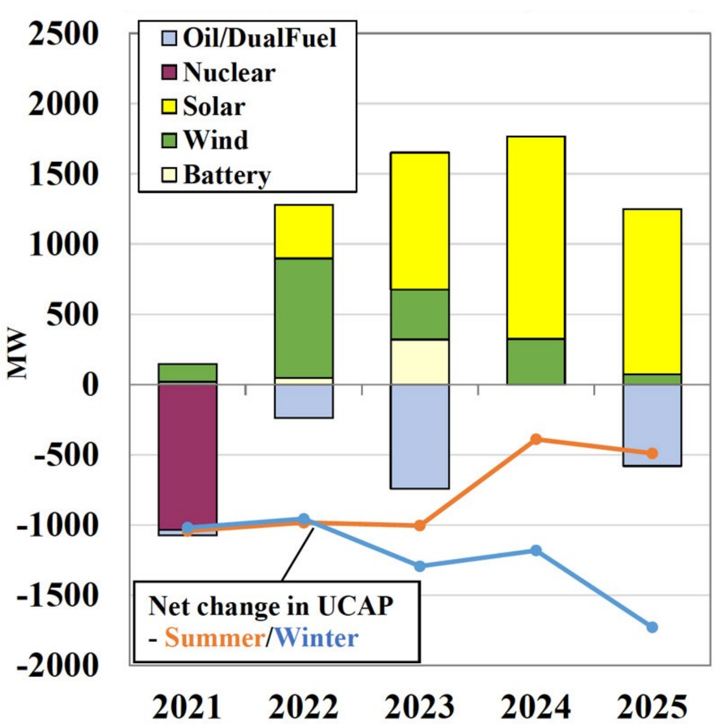
"Lastly we saw the return to normal consumption patterns, or more normal, in 2021 than they were in 2020 from COVID," LeeVanSchaick said. "We saw higher gas prices, higher electric demand [and a] very large reduction in capacity prices in New York City."

EAS Market Recommendations

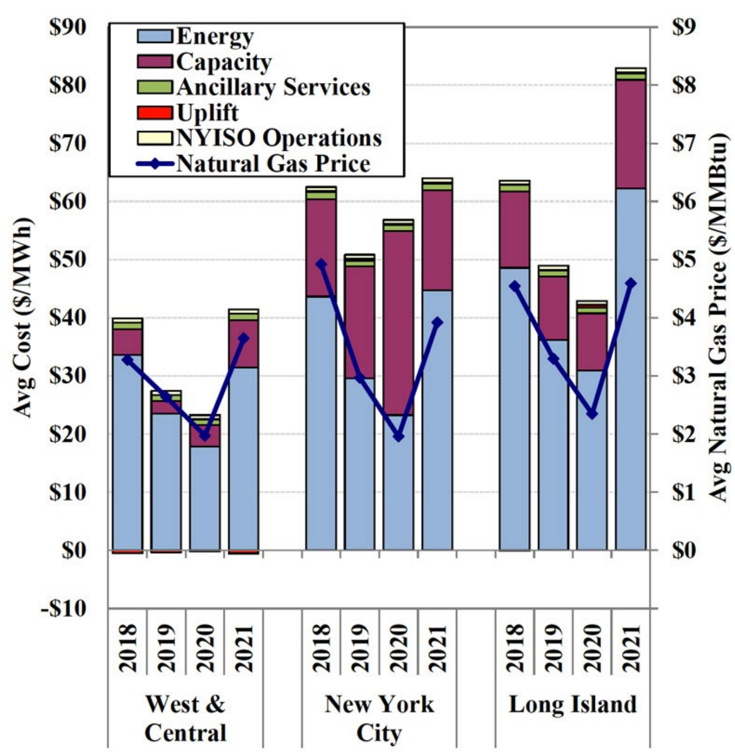
The Monitor also recommended changes to the energy and ancillary services markets, including to compensate reserve providers that increase transfer capability by allowing use of higher line ratings; increase the reserve demand curve for statewide requirements to reduce out-of-market actions and reflect risk to load; eliminate offline fast-start pricing, which undermines incentives for flexible resources; and model transient voltage recovery (TVR) constraints on the East End of Long Island in the energy market.

Increased penetration of intermittent or variable generation will accentuate the need for these changes, the report says, and the evolving resource mix will increase the need for longer lead time reserves to address net load forecast uncertainty.

"This is potentially reserves that don't have to be 10 or 30 minutes; they can be potentially just available in an hour, two hours, three hours or four hours; but it would be in a time frame that would allow the NYISO to meet what are going to be increasing requirements for reserves to deal with that load forecast uncertainty," LeeVanSchaick said. ■



Potential new entries include intermittent renewables principally motivated by REC solicitations and potential retirements include a number of dual fuel peaking units leaving through 2025. | *Potomac Economics*



All in price trends | *Potomac Economics*

PJM News

PPL Completes Acquisition of Narragansett

Utility Rebranded as Rhode Island Energy

By Michael Yoder

Narragansett Electric is rebranded as Rhode Island Energy in its acquisition by PPL. | *PPL*

PPL on Wednesday officially completed the acquisition of Narragansett Electric from National Grid, immediately rebranding the utility as Rhode Island Energy.

The acquisition, which had been stalled in court challenges, received the go-ahead on May 23 when the Rhode Island Attorney General's Office withdrew its opposition after reaching a settlement *agreement* with PPL. (See *PPL Reaches Settlement with RI AG for Acquisition of Narragansett*.)

"We are pleased to welcome the Rhode Island Energy team into the PPL family of companies, and we consider it an absolute privilege to serve the energy needs of Rhode Islanders," PPL CEO Vincent Sorgi said. "Since announcing the acquisition in March 2021, we have been working closely with key stakeholders and National Grid in an effort to facilitate a smooth transition of services and to strengthen our understanding of the needs of customers in these communities."

PPL said the acquisition includes a two-year transition services agreement with National Grid to provide continuity of operations as Rhode Island Energy transitions to the Pennsylvania-based company's systems and processes.

The utility will be led by Dave Bonenberger, a president based in the state, and more than 1,100 local employees. PPL is also establishing a control center in Rhode Island for the state's electric and gas operations and a new customer call center.

"No job we do will be more important than delivering for our Rhode Island customers, and we're pleased to have an experienced team comprised of PPL and former National Grid employees that is committed to providing exceptional service," Bonenberger said. "The PPL name may be new here in Rhode Island, but our companies have been providing essential energy services to customers in Pennsylvania and Kentucky for over 100 years."

The acquisition completes the second portion of a deal first announced in March 2021 in which PPL sold its U.K. utility business Western Power Distribution to National Grid for nearly $11 billion. (See *PPL to Sell UK Business, Acquire Narragansett Electric*.)

PPL said it plans to host a special virtual investor day on June 9 to discuss its business strategy, long-term financial outlook and capital investment plans.

"We are excited to bring to Rhode Island our proven operating model, which emphasizes innovation, customer service and reliability," Sorgi said. ■

PJM News

Proposed NJ Solar REC Program Wins Initial Support

By Rich Heidorn Jr.

Utility scale solar project under construction | *CS Energy*

A New Jersey straw proposal to award solar renewable energy credits (SRECs) through annual procurements, with incentives for projects incorporating storage, won initial support from stakeholders in a Board of Public Utilities meeting Thursday.

Representatives of the Division of Rate Counsel, the Solar Energy Industries Association (SEIA) and a solar developer expressed broad support for the *Competitive Solar Incentive program* (CSI), developed by BPU staff and Daymark Energy Advisors (Docket *QO21101186*).

The CSI program is one half of the Successor Solar Incentive program adopted by the BPU in July 2021 to implement the Clean Energy Act of 2018 and the Solar Act of 2021 and double the state's solar footprint by adding 3,750 MW of new capacity by 2026. (See *NJ Sees Solar Growth in Reduced Incentives*.)

The other half of the BPU's initiative is the Administratively Determined Incentive (ADI) program, which offers a fixed incentive for net-metered residential projects, net-metered nonresidential solar projects of 5 MW or less and community solar programs.

The 2018 law directed the BPU to redesign the state's solar incentives and close the Legacy SREC program once it reached 5.1% of the power sold, a threshold attained on April 30, 2020. (See *Solar Subsidy Program Ending in New Jersey*.)

As required by the 2021 law, the CSI program will use competitive procurements to target an average of 300 MW of new solar projects annually. All grid supply projects — front-of-the-meter projects that sell into the PJM wholesale market and net-metered non-residential projects greater than 5 MW — will be eligible to participate. (See *NJ Solar Proposal Seeks More Market Competition*.)

Five Tranches

The straw proposal recommends that the CSI program be structured as five separate procurement tranches to ensure that a range of types of competitive solar projects qualify to receive payments (called SREC-IIs) despite their different project cost profiles:

1. Basic Grid Supply: All grid supply projects that do not qualify for one of the other tranches below (e.g., greenfield solar projects).
2. Grid Supply on the Built Environment: Solar installed on rooftops, raised carports or similar installations.
3. Grid Supply on Contaminated Sites and Landfills: Any currently contaminated portion of a property on which industrial or commercial operations were conducted and a discharge of contaminants occurred; or a properly closed sanitary landfill facility.
4. Net-metered Nonresidential Projects above 5 MW: Under the Solar Act of 2021, net metered solar projects of 5 MW or less qualify for inclusion in the ADI program.
5. Storage Paired with Grid Supply Solar.

Projects eligible to compete in Tranche 2 or 3 would automatically also be eligible for Tranche 1. If some of the Tranche 1 awards go to projects that qualify in the specialized tranches, they would be removed from consideration in the subsequent tranches.

Price Premium to Reduce Open Space Development

The 2021 law requires that the "development of grid supply solar should be directed toward marginal land and the built environment and away from open space, flood zones and other areas especially vulnerable to climate change."

The straw proposal said that considering the projects in separate tranches "recognizes that NJBPU may choose to select these projects even if they come at some premium over greenfield solar development, while establishing a competitive structure to set an appropriate market price for these projects."

Staff noted that solar on contaminated sites and landfills might face higher costs of mitigating contamination and securing permits but that encouraging projects on such sites would reduce development pressure on open space. The state had 230 MW of solar operating on landfills and brownfields as of the end of February.

Staff said it is uncertain how many qualifying large net-metered projects are likely to compete in the CSI program because of the "unpredictability of a competitive procurement" and limitations on the number of appropriate sites.

"However, the [Transition Incentive program that succeeded the Legacy program] received a robust response from large (> 5 MW) net-metered projects of approximately 120 MW, suggesting that there could be significant potential participation by large net-metered projects," staff said. "In fact, net-metered projects may have some inherent advantages in a competition against wholesale projects, since they already receive some degree of subsidy, compared to wholesale projects, in the form of net metering credits higher than the wholesale cost of power."

To ensure the continued diversification of resources as required by the 2021 law, "it would not be desirable to risk awarding all CSI program capacity to net-metered projects," staff said. "By breaking these projects out into their own tranche, NJBPU will be able to award SREC-IIs to the most competitive net-metered projects, while ensuring that there is still room in the program for other types of projects."

Storage Adder

Although the 2018 law requires New Jersey to achieve energy storage goals, the state currently lacks an independent energy storage program.

The straw proposal notes that solar projects with storage can obtain higher capacity ratings in PJM markets and are able to arbitrage by storing energy produced when wholesale prices are low and selling when they rise.

Staff said the dedicated storage tranche in the CSI program would provide a storage adder to solar projects that qualify for SREC-IIs in competition with other solar projects and also offer storage competitive within the storage tranche.

Solar-plus-storage projects would make two-part bids: a solar-only SREC-II price and a storage adder price. The project would first be considered as a solar-only project; if it receives an award, its proposed storage adder price would then be considered separately in the storage tranche.

The storage incentive would be limited to four times the total megawatts of the solar project (e.g., 4 MWh of storage per megawatt of solar capacity).

Bidding, Maturity Requirements

Staff recommended adopting project qualification and maturity requirements to ensure that selected projects are likely to reach commercial operation.

To prequalify, projects would need to demonstrate "a sufficiently advanced position in the PJM queue (taking into account the realities of the ongoing PJM interconnection reform process)" or a comparable interconnection position in a state-jurisdictional queue. Net-metered projects would be required to show conditional approval of their utility interconnection request.

Projects would be required to pay a $1,000/MW nonrefundable solicitation participation fee and achieve commercial operation three years after registration in the program.

"Using prequalification through queue position would avoid having to engage in a more complex, subjective process relating to permitting, securing right of ways or evidence of public support," staff said.

Staff proposed resources be paid on a price as bid basis with confidential project cost caps. Among the 34 questions staff seeks input on is whether the SREC-IIs should be fixed or indexed to wholesale energy prices.

Staff recommended all tranches be included in a single procurement to be held once per year. "However, some adjustments to this schedule may be appropriate to coordinate with the implementation of PJM's new queue procedures, should these be approved," staff said.

Tranche Number	Tranche	Initial Procurement target
1	Basic Grid Supply	140 MW
2	Grid Supply on the Built Environment	80 MW
3	Grid Supply on Contaminated Sites and Landfills	40 MW
4	Net Metered Non-residential Projects above 5 MW	40 MW
	Total	**300 MW**
5	Storage	160 MWh

Proposed year 1 target procurements by tranche | *NJBPU*

Comments

During Thursday's hearing, Sarah Steindel, of the state's Division of Rate Counsel, expressed support for the tranches. "We think that the proposed five tranches are a sufficient number to recognize the legislature's preferences for certain types of projects, but yet, each tranche is still broad enough to create robust competition."

She said the Rate Counsel "strongly support[s] the proposal to utilize a confidential bid price cap for each tranche" but was still evaluating the proposal for solar-plus-storage. "We have some concern that … some of the tranche targets may be aggressive, and we recommend that the board consider what options it may have should some or all of the specialized tranches go unfilled."

Speaking on behalf of SEIA, Nitzan Goldberger of Borrego Solar Systems, was also supportive.

"A pay as bid system, coupled with strong project maturity requirements for bidders, should avoid overpayment to bidders and avoid windfall [profits], minimize project attrition and ensures that the awarded projects reach completion," she said.

Matt Tripoli, of solar developer *CS Energy*, echoed Steindel's concerns that some of the tranches might go unfilled and suggested the BPU consider annual rather than monthly megawatt limits for the storage adder. We're "glad to see that Daymark and the BPU are drawing lessons from some of those other states and how they're constructing this program," he said.

Fred DeSanti, the executive director of the New Jersey Solar Energy Coalition, said that by adopting a two-step process for storage-plus-solar, "we may be losing some economies because a lot of times when we're pricing projects … if you do it on a joint basis, you can achieve some lower [costs] than you might by doing it independently."

Feedback Sought

Staff will accept comments on the straw proposal until 5 p.m. June 20.

The BPU will hold two additional stakeholder meetings:

- *Wednesday, June 1, 1 p.m.*: Project prequalification, bid participation fees, and commercial operation date requirements.
- *Monday, June 6, 1 p.m.*: Auction price results, SREC-II payment structure. ■

PJM News

PJM MRC Briefs

Dynamic line ratings, such as those provided by LineVision's overhead line monitoring system, can allow increased transmission capacity and provide grid operators with real-time situational awareness of potential problems. | *LineVision*

Start-up Cost Offer Development Proposal Endorsed

Stakeholders at last week's PJM Markets and Reliability Committee meeting unanimously endorsed a revised proposal from the RTO and the Independent Market Monitor addressing start-up cost offer development worked on through the Cost Development Subcommittee (CDS).

Tom Hauske, principal engineer in PJM's performance compliance department, *reviewed* the joint proposal to revise *Manual 15: Cost Development Guidelines*, along with revisions to the *tariff* and *Operating Agreement*.

The CDS initially brought two proposals for first reads to the October MIC meeting, but a vote on the proposals was postponed, allowing for more discussions and stakeholders to reach consensus on a single proposal. (See "Start-up Cost Offer Development," *PJM MIC Briefs: Oct. 6, 2021*.)

Manual 15 allows the start-up costs for combined cycle units to include fuel costs after generator breaker closure and synchronization to the grid, a feature not available to other unit types, such as steam and nuclear plants. The revisions align start-up costs for all units with a soak process, or units that use steam turbines.

For units with a soak process, including steam, combined cycle and nuclear units, some of the soak costs will be included in the start-up costs from PJM's notification to the "dispatchable output" and from the last breaker open to the shutdown process.

Units that don't have a soak process, like combustion turbines and reciprocating engines, maintain the status quo, with start-up costs that include costs from the time of PJM's notification to the first breaker close and from the last breaker open to the conclusion of the shutdown process.

The approved revisions include several other changes to Manual 15 to provide additional guidance and clarification, Hauske said, such as equations to calculate start-up costs, station service calculations for units with and without a soak process, and unit-specific parameter limits on includable costs.

Manual 15 allows generators to include an additional labor cost in their start-up costs, Hauske said, but generators already are permitted to include the labor cost in the unit's capacity offer through its avoidable-cost rate (ACR). The revisions eliminate the labor cost language in the tariff and OA offer cap sections and the start-up cost calculation so that all the operating labor is includable in the ACR.

PJM is providing a six-month window for implementation to allow market sellers the opportunity to have their fuel costs or net generation used for the offset to be reviewed by the Monitor prior to the revisions going into effect.

Hauske described the new start-up cost definition included in Manual 15, which states it will "consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, maintenance adders, emissions allowances/adders and station service power cost. Start costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold."

Adrien Ford of Old Dominion Electric Cooperative offered a *friendly amendment* that was

PJM News

adopted by stakeholders to the end of the definition, which says, "Units with a soak process include nuclear, steam and combined cycle units. Units without a soak process include engines, combustion turbines, intermittent and energy storage resources."

Ford said the suggestion came from ODEC staff to "provide clarity" for the units impacted by the changes.

"We were just looking for it to be better defined upfront when you're first reading this, so that the puzzle has some of the overview pieces up front, and then you can get into the detail pieces later," Ford said.

DEA Proposal Denied

Members rejected a PJM proposal to address changes to the Designated Entity Agreement, sending the issue back for more stakeholder discussions.

The proposal, which PJM was seeking a quick-fix approach to make changes, received a sector-weighted vote of 2.51 (50.2%), falling short of the necessary 3.33 threshold for adoption.

FERC in February rejected a filing by PJM in its Order 1000 compliance docket that would have updated the definition of "designated entity," agreeing with a coalition of stakeholders that it infringed on their due process rights. (See *FERC Rejects PJM Redefinition of 'Designated Entity' Under Order 1000*.)

Ken Seiler, vice president of PJM's planning department, said the proposal was meant to accommodate the "lack of clarity" in the OA regarding the DEA. Seiler said the existing OA language is "a little too broad," and PJM wanted to clear up the definition.

Seiler said PJM wants to look at all construction-related activities in the RTO to make sure the process is being done efficiently.

"We'd like to take a holistic look at everything and consider how this is impacting any risk to any stakeholders, consumers or ratepayers; how it's impacting our ability to get work done; how it's impacting our coordination with all the other projects coming through the [transmission planning] process," Seiler said.

Augustine Caven, manager of PJM's infrastructure coordination department, *presented* the proposal consisting of a *problem statement*, *issue charge* and OA *revisions*.

Caven said the OA language can be interpreted differently because of the "imprecise" use of the term "designated entity," so PJM's proposal called for several revisions to "eliminate the ambiguities" and "align the OA language with the intent and use of the DEA."

"Given the urgency associated with compliance considerations and the narrow scope of the issue charge, PJM believes this issue is well suited for the quick-fix process," Caven said.

Several stakeholders questioned the use of the quick-fix process on the issue, saying the complexity of DEAs warranted more in-depth discussions.

Two different alternatives to PJM's proposal were also presented for stakeholder consideration. Greg Poulos, executive director of the Consumer Advocates of the PJM States, *offered* an *issue charge* on behalf of the Delaware Division of the Public Advocate to allow for more education on the DEA process and the formation of a senior task force to work on any possible OA changes if needed.

Denise Foster Cronin of the East Kentucky Power Cooperative *presented* an alternative *issue charge* from EKPC, Exelon and Public Service Enterprise Group that called for endorsing PJM's OA changes and also starting a stakeholder process to discuss other possible changes to the DEA.

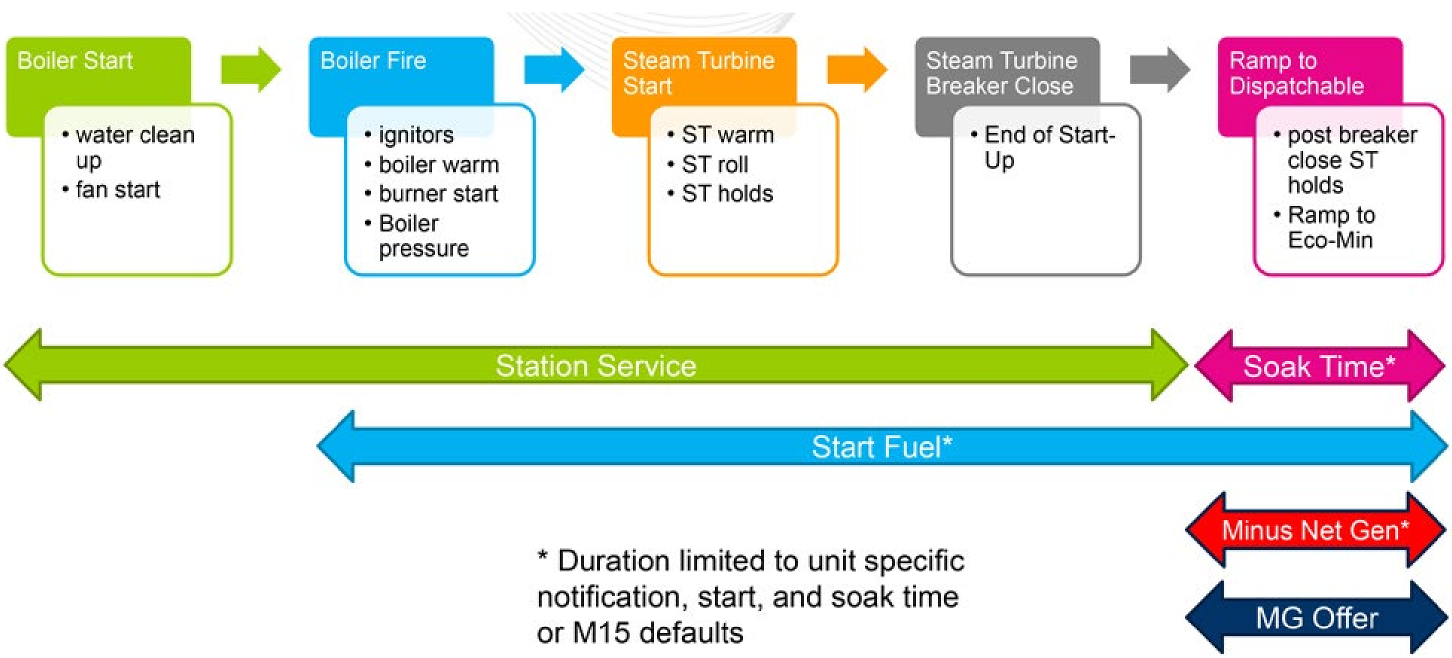
In a sector-weighted vote of 3.95 (79%), members voted to table the two additional proposals until the June MRC meeting.

Dynamic Line Ratings Proposal Endorsed

Members unanimously endorsed PJM's proposal and manual revisions supporting the interim integration of dynamic line ratings (DLRs) into its operations.

Chris Callaghan, PJM senior business solution engineer, *reviewed* the proposal that included corresponding revisions to *Manual 1: Control Center and Data Exchange Requirements*, *Manual 3: Transmission Operations* and *Manual 3A: Energy Management System Model Update and Quality Assurance*.

PPL is tentatively scheduled to go live in June



PJM's revised steam unit start-up cost offer procedure | *PJM*

PJM News

with a DLR system on some of its transmission lines, Callaghan said, and PJM wanted to "enable the operational implementation of dynamic ratings" through temporary manual revisions, which will be in place pending submission of the RTO's FERC Order 881 compliance filing.

In December, FERC ordered transmission providers to end the use of static line ratings in evaluating near-term transmission service and required transmission providers to employ ambient-adjusted ratings for short-term transmission requests of 10 days or less for all lines that are impacted by air temperature. (See *FERC Orders End to Static Tx Line Ratings*.)

The manual revisions are meant to have new guidance and requirements related to the operational and technical implementation of DLR systems, Callaghan said. Some of the manual revisions include adding timeline requirements to notify PJM about any new DLR systems to be installed on the grid and to provide details on requirements for real-time and forecasted DLR submissions.

Rate and Waiver Filings

Steve Pincus, associate general counsel of PJM, *reviewed* a proposed *problem statement* and *issue charge* addressing service to members' tariff rate and waiver filings under the RTO's governing documents.

In 2018, Pincus said, PJM proposed a new OA requirement as part of a larger group of changes from the Governing Document Enhancement and Clarification Subcommittee (GDECS) that called for ensuring the RTO is "properly served with members' and interconnection customers' rate and waiver filings" impacting PJM and stakeholders' rights and obligations.

Pincus said a motion was made at the September 2018 MRC meeting to defer the consideration of the revisions after some stakeholders objected to the scope of the changes coming from the GDECS. PJM approached stakeholders earlier this year about reviving discussions on the issue.

The proposed problem statement says that PJM has experienced incidents when relevant FERC filings are made by members but are not served to the RTO, including tariff and service agreement filings.

"Service of such filings on PJM is important to ensure PJM is able to intervene and participate in such proceedings to protect the interests of PJM members and markets," the problem statement said.

Key work activities in the issue charge include education on PJM's need to be served with rate, waiver and other filings and the development of a solution to include any changes to governing documents or manuals.

Pincus said work on the issue charge is planned for special sessions of the MRC and is expected to take six months.

Consent Agenda

Stakeholders unanimously endorsed several manual changes as part of the MRC consent agenda. They included:

- revisions to *Manual 3: Transmission Operations* resulting from a periodic review. The changes include updating stability limitation process language in accordance with docket ER21-1802 and aligning language with the current TO/TOP matrix language.
- revisions to *Manual 11: Energy & Ancillary Services Market Operations*, *Manual 12: Balancing Operations* and *Manual 28: Operating Agreement Accounting* addressing conforming changes for stability limits in markets and operations. FERC ruled in February that PJM has the right to refuse lost opportunity cost payments to generators that are temporarily required to limit output to prevent loss of synchronization and additional strain on the system during transmission outages.
- revisions to *Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis* addressing an effective load-carrying capability model run timing update. PJM rules allow voluntary submission of unit-specific wind and solar parameters for development of backcasts for newer resources, but manual language has an expiration date of March 1 for voluntary submissions. The quick fix removes the March 1 expiration date.
- revisions to *Manual 36: System Restoration* resulting from a periodic review. The minor changes include replacing the System Restoration Coordinators Subcommittee with System Operations Subcommittee and updating the under-frequency load shed table with new data. ■

— Michael Yoder

Company Briefs

BLM Approves 416-mile PacifiCorp Tx Line

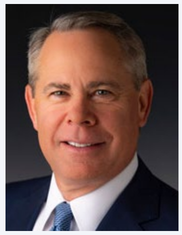
The Bureau of Land Management last week announced it has notified PacifiCorp that it can proceed with its 416-mile Energy Gateway South Transmission line that will run from Wyoming to Utah.

Gateway South is part of a broader plan by PacifiCorp to install roughly 2,000 miles of new transmission lines across the West.

Construction is expected to begin in June, with the line going into service in 2024.

More: *The Colorado Sun*

John Ketchum Appointed Chairman of NextEra



The NextEra Energy Board of Directors last week appointed President and CEO **John Ketchum** as chairman of the board, effective July 2.

Ketchum became president and CEO on March 1. Prior to that, he had served in several senior executive positions since joining the company in 2002.

Ketchum will succeed Jim Robo, who is retiring.

More: *NextEra*

TotalEnergies to Buy 50% of Renewables Company Clearway

TotalEnergies last week said it has agreed to buy 50% of the Clearway Energy Group, which is the fifth-largest renewables company in the U.S.

The company said the acquisition would see it team up with Global Infrastructure Partners (GIP). As part of the deal, GIP will receive $1.6 billion in cash and an interest of 50% minus one share in the TotalEnergies subsidiary that holds its 50.6% ownership in SunPower Corporation.

Clearway has 7.7 GW of wind and solar assets in operation through its subsidiary CWEN and a 25 GW pipeline of renewable and storage projects.

More: *Reuters*

Federal Briefs

Supreme Court Allows Greenhouse Gas Cost Estimates

The Supreme Court last week said it would allow the Biden administration to account for the costs of greenhouse gas emissions in regulatory actions, rejecting an emergency application from Louisiana and other Republican-led states to block the use of a formula that assigns a monetary value to changes in emissions.

The case concerned an interagency working group created by President Barack Obama that in 2010 announced a framework for assessing the costs of greenhouse gas emissions. President Donald Trump disbanded the group; Biden revived it. In January 2021, Biden instructed the group to develop "estimates of the monetized damages associated with incremental increases in greenhouse gas emissions."

In February 2021, the group published interim estimates that were identical to those in place in 2016 but adjusted for inflation. Louisiana and other states sued, saying the group's actions had not been authorized by Congress and had not followed administrative procedures.

More: *The New York Times*

G-7 Puts Coal on Notice, Could Boost Climate Aid

Officials from the Group of Seven wealthy nations last week announced they will aim to largely end greenhouse gas emissions from their power sectors by 2035, making it highly unlikely they will burn coal beyond that year.

G-7 ministers also announced a target to have a "highly decarbonized road sector by 2030" and recognized the need to provide developing countries with additional financial aid to cope with loss and damage caused by global warming.

More: *The Associated Press*

MCLB Becomes First US Base to be Net Zero

The Marine Corps Logistics Base (MCLB) in Albany, Ga., last week announced its net-zero status and became the first defense base in America to produce 100% of the energy it uses.

MCLB, which began the net zero process in 2005, said it now saves $10 million per year.

More: *WALB*

US Installs Clean Power Record in Q1

The U.S. installed 6,619 MW of utility-scale clean power capacity in the first three months of 2022, marking a record first quarter for such installations, according to a report by American Clean Power.

The 6.6 GW was an increase of 11% compared to the first quarter of 2021.

The growth was driven by battery storage installations, which expanded 173% to 758 MW. Utility-scale solar additions rose 11% to 2,997 MW, while wind installations declined by 3% to 2,865 MW.

More: *Renewables Now*

Report: Climate Inaction Could Cost $178T over Next 50 Years

A report released by consulting firm Deloitte last week suggested that if the world fails to act on climate change and reduce carbon emissions, it could cost the global economy $178 trillion over the next 50 years.

However, the report said zeroing out global greenhouse emissions by 2050 could add $43 trillion over the same period.

The report said if the world warms by 3 degrees Celsius (5.4 Fahrenheit) compared to pre-industrial times, it would hinder economic growth in every region. Economic opportunities would dwindle because countries would spend money on repairs instead of innovations.

More: *Grist*

Greenhouse Gases Trapping 49% More Heat than 30 Years Ago

The National Oceanic and Atmospheric Administration last week released an assessment that found that human-caused greenhouse gas pollution trapped 49% more heat in 2021 than in 1990.

The NOAA found that carbon dioxide, which can last 1,000 years in the atmosphere, is the biggest contributor and is responsible for 80% of the increase.

More: *The Hill*

Forecasters Predict Above-average Hurricane Season

The National Oceanic and Atmospheric Administration last week announced it is predicting an above-average hurricane season with as many as 10 storms.

Three to six of those hurricanes could be major, meaning wind speeds of 111 mph or higher. Between 14 to 21 named storms are possible. If the predictions hold, it will be a record seventh consecutive year of above-normal hurricane activity.

The hurricane season runs from June 1 through Nov. 30.

More: *NJ Spotlight News*

State Briefs

COLORADO

Xcel, PSCo to Pay Fine Over Coal Ash Storage at Comanche Power Plant

The EPA last week announced a settlement with the Public Service Company of Colorado (PSCo) that will result in a $925,000 fine regarding the storage of coal ash at the Comanche power plant.

The agreement commits PSCo to improved monitoring of the area's groundwater, the EPA said. The company must also collect and analyze data on groundwater, make the information public, and stop using coal ash ponds beyond their closure dates.

Xcel Energy originally planned to retire the Comanche plant by 2040 but has since moved the date up to Jan. 1, 2034.

More: *KCNC*

ILLINOIS

Peoples Gas Wipes Out Balances for Thousands of Overdue Bills

Peoples Gas last week announced it will help Chicago-area customers by wiping out the balances of about 12,000 residents with overdue heating bills by the end of June.

Peoples Gas has seen record profits due to increased federal funding and state aid. Meanwhile, a Sun-Times analysis found that nearly half of all households in some Chicago ZIP codes were behind on their gas bills this spring.

Customers have until May 31 to apply for assistance.

More: *Chicago Sun-Times*

IOWA

Clinton County Approves Solar Farm

The Clinton County Board of Supervisors last week unanimously voted to approve the $250 million Hawkeye Solar Project.

The 1,500-acre farm is expected to start construction in the fall and take 12 to 18 months to complete.

More: *WQAD*

Des Moines Approves Franchise Agreement Extension with MidAmerican

The Des Moines City Council last week voted 4-1 to extend the city's electric and natural gas franchise agreements with MidAmerican Energy. The current agreement expires on June 15.

The city also added a provision for developing an implementation plan for clean energy goals. The agreement would allow the city to amend the 13-year agreements after five years, if necessary. Des Moines hopes to reduce its greenhouse emission from 2010 levels by 45% by 2030 and achieve net-zero emissions by 2050.

The implementation plan will outline processes, responsibilities, costs and ways to achieve the goals. The tentative deadline for the plan is Dec. 30.

More: *Des Moines Register*

MINNESOTA

Judges Say Customers Should Bear Costs from February 2021 Storm

Administrative Law Judges Jessica Palmer-Denig and Barbara Case last week concluded that state natural gas utilities acted "prudently" during the February 2021 storm and should be allowed to pass on $660 million in extra costs to customers.

The Public Utilities Commission last year ordered an investigation into the prudency of the charges — 62% of which were run up by CenterPoint Energy. The Department of Commerce and Attorney General's Office concluded that CenterPoint, Xcel Energy, Minnesota Energy Resources Corp. and Great Plains Natural Gas made critical mistakes in their gas procurement procedures before and during the storm. However, the judges ruled that the utilities' strategies were sound and the $660 million in extra costs were "prudently" incurred.

The PUC is expected to decide on the matter this summer.

More: *Star Tribune*

MISSOURI

PSC Approves Liberty Rate Increase

The Public Service Commission recently approved a rate increase for Liberty, which will see its electric revenue increase by about $35.5 million.

The average residential customer will see their bills rise by $10, effective June 1.

More: *Missouri PSC*

MONTANA

Supreme Court Rules in Favor of Con Ed Dev

The state's Supreme Court last week ruled against the Public Service Commission and NorthWestern

Energy for requiring wind farm developer Consolidated Edison Development (CED) to pay $267 million to connect to the utility's transmission system.

CED planned to build wind farms in three counties with NorthWestern as its target customer under a 44-year-old law requiring utilities to purchase power from small generators. Those plans got hung up when NorthWestern billed CED $267 million for network upgrades. After the PSC sided with the utility, CED sued.

The court said the commission erred in requiring CED to pay for upgrades to the transmission system and that the costs went beyond what could reasonably be considered CED's share.

More: *Billings Gazette*

NORTH DAKOTA

Commission Approves Loans for Carbon Capture Projects

The Industrial Commission last week approved two loans for three carbon capture projects in the latest round of funding.

The commission approved a $100 million loan for Minnkota Power Cooperative's Project Tundra and a $15 million loan for a capture and store project at Midwest AgEnergy Group's Blue Flint Ethanol plant. The commission also approved a $1 million grant for Enerplus Resources, which seeks to capture emissions from generator engine exhaust in oil fields.

Lawmakers established a Clean Sustainable Energy Authority to help fund the commercialization of low-emissions projects. It has authorized $250 million in loans and $45 million in grant money.

More: *The Bismarck Tribune*

TEXAS

Companies Boycotting Fossil Fuels yet to Respond to Comptroller Inquiry

Twelve of the 19 financial companies accused of harboring oil and gas-boycotting policies have not responded to Comptroller Glenn Hegar's inquiry on their practices despite being past the 60-day period to do so.

In March, Hegar sent inquiries to financial companies in which pension funds are invested. The companies were identified in conjunction with Senate Bill 13, which prohibits state money from going to companies with fossil fuel-boycotting policies.

The comptroller's office said the 60-day deadline was "soft" and that any responses received after will still be accepted. However, companies that do not reply will be treated as if they do harbor boycotting policies.

More: *The Texan*

El Paso Electric Settles Rate Case, Monthly Bills to Rise

El Paso Electric and the city of El Paso announced an agreement last week in which the average monthly residential bill will increase by about $2.20 in July.

Under EPE's original request, the average residential customer might have seen an 11% to 13.4% increase, which would have been about $10 or $11 more per month.

The agreement must still be approved by the Public Utility Commission.

More: *El Paso Matters*

VIRGINIA

Appalachian Power Seeks Rate Increase

Appalachian Power last week filed for a rate increase with the State Corporation Commission that, if approved, would increase residential rates by about $2.37 a month.

Appalachian Power Consultant Teresa Hall cited increased costs from the purchase of the renewable energy, as well as costs associated with equipment installation and system reconfiguration.

More: *Martinsville Bulletin*

W&L University to Generate 100% of Power from Solar Energy

Washington and Lee University last week announced it has completed a deal to purchase enough solar energy to match 100% of the university's annual electricity consumption.

The power purchase agreement with SunEnergy1, which will build, own and operate a 17-MW solar farm in North Carolina, will provide the university with 11 MW — equivalent to 100% of campus electricity use.

More: *Cardinals News*

WASHINGTON

Yakima County Approves Black Rock Solar Facility

Yakima County Hearing Examiner Gary Cuillier last week approved a conditional use permit for the 94-MW Black Rock Solar Energy Project.

The project will feature 264,000 solar panels spread over 1,060 acres.

Developer BayWa r.e. Solar Projects hopes to begin construction in the spring of 2023 with the goal of having the facility operational by the end of 2024.

More: *Yakima Herald-Republic*