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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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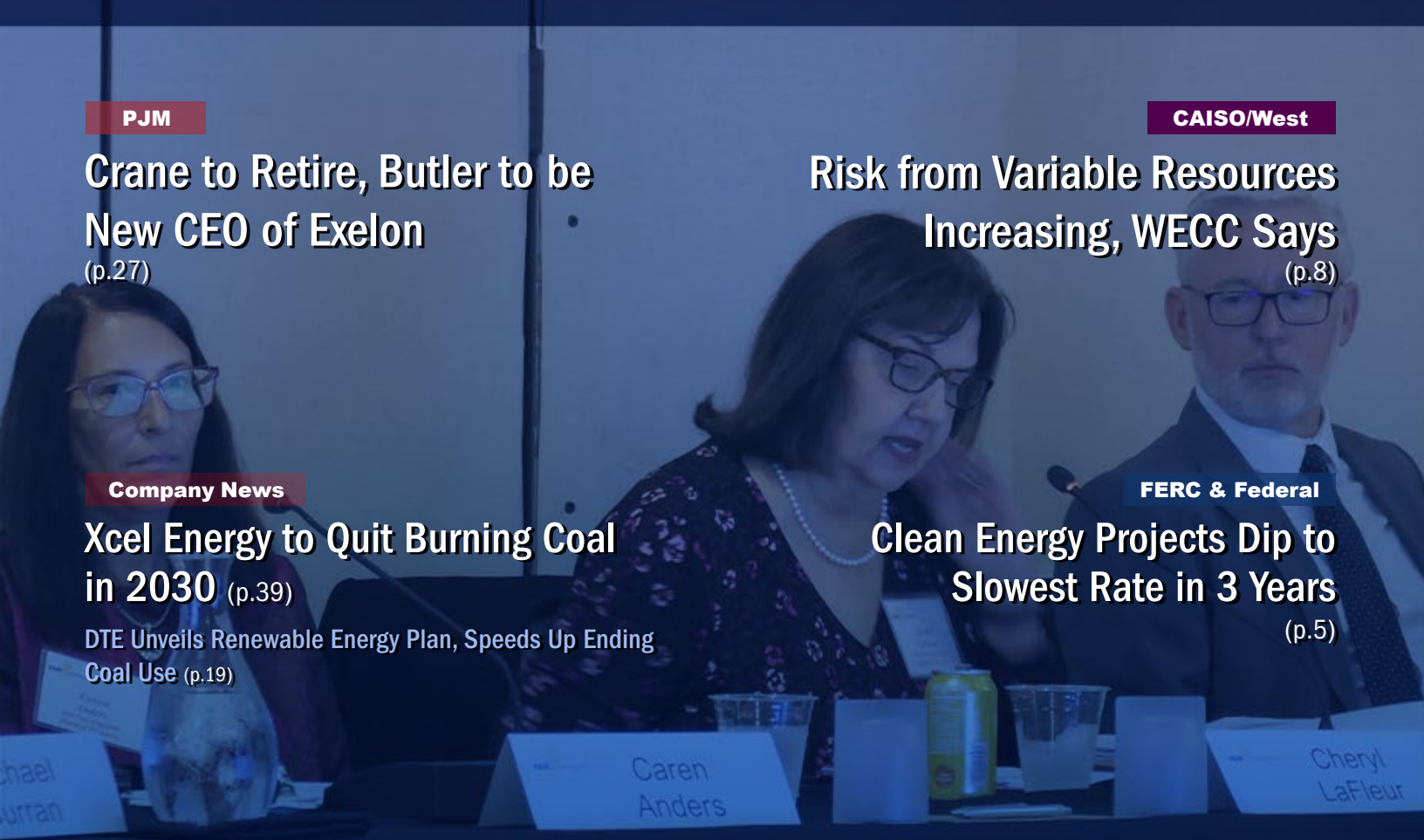

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Eau Rikhotso

Assistant to the Publisher
Tri Bui

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 658-6885

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In this week's issue

Counterflow

By Steve Huntoon

More Happy Talk

By Steve Huntoon

Fact

Steve Huntoon | *Steve Huntoon*

Inside our industry it's no secret that net zero — or anything like it — is going to be incredibly expensive if you want to keep the lights on.

There are the global challenges I've written about,[1] with the U.N. highlighting the most recent shortfalls.[2] There's our national picture, where past attempts to make net zero look easy have been discredited.[3] And we've had rosy state modeling that, as I've pointed out before, would leave California without any electricity for big parts of winter months;[4] ditto for Germany.[5]

The most recent reality checks come from David Rapson and James Bushnell[6] and from *The Economist*.[7] The case mounts for a Plan B.[8]

Fantasy

Meanwhile there remains a fantasy that net zero is feasible and affordable — because it must be.

Thus Hurricane Ian brought not only mass destruction and suffering, but also predictable attempts to find a silver lining for a net-zero future.

CNN, "60 Minutes," *Newsweek*, Yahoo, *Fortune*, Slate, *The Atlantic*, MSN, *Time*, *The Hill*, Axios, RMI and many others, even the *New York Post*, ran gushing stories about the Babcock Ranch planned community in southwest Florida, claiming that the lights stayed on during the hurricane because of solar panels and battery storage.[9] Sample headlines:

- "This 100% solar community endured Hurricane Ian with no loss of power and minimal damage"[10]
- "The U.S.'s 'first solar-powered town' kept its electricity and water running during Hurricane Ian — and became a model for how to adapt to climate change"[11]
- "Babcock Ranch: Solar-powered 'hurricane-proof' town takes direct hit from Hurricane Ian, never loses electricity"[12]
- "Solar-powered town in Florida kept lights on during Hurricane Ian"[13]

Babcock Ranch hosts 150 MW of solar capacity over 870 acres of land in addition to a 10-MW/40-MWh battery that can power 10,000 homes for four hours. | *Babcock Ranch*

Counterflow

By Steve Huntoon

One Wee Problem: Ain't So

Babcock Ranch saw its last sunlight around 3 p.m. on Sept. 26 as Hurricane Ian covered southwest Florida. From then on, there was negligible sunlight for the solar panels to provide power to homes or to recharge the battery, until 9 a.m. on Sept. 29.[14] Total time without sunlight: 66 hours.

After loss of sunlight, the 10-MW/40-MWh battery[15] could have powered 10,000 homes for four hours at average electric home usage of 1 kWh,[16] leaving about 62 hours without anyone getting any power from the solar/battery system at Babcock Ranch.[17]

So how did the lights stay on? The same way they stayed on wherever distribution lines[18] weren't taken out by Ian: fossil fuel and nuclear generation; nothing to do with solar generation and battery storage.

To summarize, the solar/battery system could have supplied power to some homes for four hours during Ian, while fossil fuel and nuclear generation supplied power for about 62 hours.

One News Organization Got it Right

One news organization got the story right by interviewing the CEO of the company developing Babcock Ranch. Ironically, it's not even a U.S. news organization, but Canadian.[19] In an interview this CEO honestly says: "We're the first solar power town in America. We have 150 MW; that's 700,000 panels on about 340 hectares. Now that's all fine and good, but when a storm comes in like Ian did, and there's cloud coverage for a long period of time, you can no longer depend on that solar energy. So we then had to draw from the main utility."

What a concept: interviewing someone who actually knows something. But for major U.S. media, it's the happy talk that matters. ■

[1] https://energy-counsel.com/wp-content/uploads/2022/05/We-are-Going-to-Need-a-Plan-B-RTO-Insider-5-10-22.pdf.

[2] https://wedocs.unep.org/bitstream/handle/20.500.11822/40932/EGR2022_ESEN.pdf?sequence=8

[3] https://www.energy-counsel.com/docs/cue-more-pixie-dust.pdf; https://www.energy-counsel.com/docs/Cue-the-Pixie-Dust.pdf; https://www.energy-counsel.com/docs/Grid-Batteries-Kool-Aid-Once-More-with-Feeling-RTO-Insider-12-5-17.pdf; https://www.energy-counsel.com/docs/Alternative-Facts-and-Global-Warming.pdf.

[4] https://www.energy-counsel.com/docs/No-Carb-California.pdf.

[5] https://www.energy-counsel.com/docs/German-La-La-Land.pdf.

[6] https://haas.berkeley.edu/wp-content/uploads/WP332.pdf.

[7] https://www.economist.com/leaders/2022/11/03/the-world-is-missing-its-lofty-climate-targets-time-for-some-realism.

[8] Please see my column referenced in footnote 1.

[9] In addition to headlines below that are individually cited, please see https://www.newsweek.com/babcock-ranch-hurricane-ian-florida-future-town-planning-1752747; https://www.yahoo.com/video/babcock-ranch-weathered-hurricane-ian-210536177.html; https://slate.com/technology/2022/10/hurricane-ian-renewable-energy-florida-babcock-ranch-solar.html; https://www.theatlantic.com/ideas/archive/2022/10/hurricane-ian-florida-real-estate/671629/; https://www.msn.com/en-us/news/us/america-s-first-solar-powered-town-was-a-hurricane-success-story-as-millions-of-other-floridians-lost-power-see-inside-babcock-ranch/ar-AA12ABss?li=BBnbcA1; https://time.com/6225970/climate-proof-towns-extreme-weather/; https://thehill.com/changing-america/sustainability/infrastructure/3685296-solar-powered-community-kept-the-lights-on-during-hurricane-ian/; https://www.axios.com/2022/10/11/hurricane-ian-solar-power-off-grid; https://rmi.org/our-lights-stayed-on-during-hurricane-ian/; https://www.cbsnews.com/news/hurricane-ian-florida-solar-power-babcock-ranch/; https://www.entrepreneur.com/science-technology/a-solar-powered-florida-town-withstands-hurricane-ian/436750; https://www.businessinsider.com/hurricane-ian-solar-powered-florida-town-didnt-lose-power-babcock-ranch-2022-10.

[10] https://www.cnn.com/2022/10/02/us/solar-babcock-ranch-florida-hurricane-ian-climate

[11] https://fortune.com/2022/10/05/babcock-ranch-florida-solar-hurricane-ian-flood-insurance/.

[12] https://www.cbsnews.com/news/babcock-ranch-solar-power-hurricane-ian-60-minutes-2022-10-09/.

[13] https://nypost.com/2022/10/17/solar-powered-town-in-florida-kept-lights-on-during-hurricane-ian/.

[14] To confirm this, please go to www.wunderground.com and search location "KFLPUNTA222" (Babcock Ranch DM). Under Weather History enter a day, click View, and then scroll down to Solar Radiation data (please note that full sunlight is about 1,000 W/square meter). The data at this location are confirmed by other nearby stations, KFLPUNTA361 and KFLLABEL37.

[15] https://www.utilitydive.com/news/fpl-adds-40-mwh-battery-to-solar-array-claiming-largest-combined-system/518959/.

[16] According to Energy Information Administration data, average home electric usage in Florida is 1,142 kWh/month. https://neo.ne.gov/programs/stats/pdf/145_Residential.pdf. Excluding space heating/cooling (36% of total usage, https://www.myfloridahomeenergy.com/help/library/choices/home-energy-basics/#sthash.TVHeGPY8.dpbs) because temperatures during Ian were 70 to 80 degrees Fahrenheit, leaves 731 kWh/month or 1 kWh. Average home usage of 1 kWh for 10,000 homes aggregates to 10 MWh (the maximum hourly output of a 10 MW battery), thus draining a 40-MWh battery in four hours.

[17] The solar/battery project is reported to power many more homes than in Babcock Ranch proper. If the project had been limited to supplying just Babcock Ranch's 2,000 existing homes (https://babcockranch.com/babcock-ranch-exceeds-2000-home-sales/), the battery could have lasted 20 hours, with fossil fuel and nuclear generation supplying the remaining 46 hours.

[18] Power can also be taken out by loss of transmission (as opposed to distribution) lines, but there was reportedly no loss of transmission lines from the hurricane. RTO Insider, Nov. 1, 2022, page 3.

[19] https://www.cbc.ca/news/canada/nova-scotia/babcock-ranch-florida-climate-change-storm-resiliency-solar-power-1.6615332.

FERC/Federal News

Clean Energy Projects Dip to Slowest Rate in 3 Years

American Clean Power's Q3 Report Cites Supply Chain, Tariffs, Taxes

By John Cropley

The clean energy industry experienced its slowest quarter in three years this summer, an industry group reported Wednesday.

The American Clean Power Association said the federal Inflation Reduction Act — passed in August — holds promise for future growth. But the industry was held back in the third quarter by supply chain constraints, trade and tariff issues, and uncertainty over tax policy.

Clean power projects totaling 14.2 GW capacity were delayed in the third quarter, and more than half of them had been delayed in the second quarter, as well. ACP said it is aware of 36.2 GW of delayed projects and 3.5 GW of terminated or canceled projects.

For the quarter, new utility-scale projects totaling 3.4 GW were installed, 22% less than in the third quarter of 2021.

Wind power installations were down 78% and solar down 23%. The exception was battery storage, which is having its best year on record.

JC Sandberg, interim CEO of ACP, said policy and regulatory issues continue to hamper growth.

"The solar market has faced repeated delays as companies struggle to obtain panels as a result of an opaque and slow-moving process at U.S. Customs and Border Protection," Sandberg said in a news release. "Policy uncertainty around tax incentives constrained wind development, underscoring the near-term need for clear guidance from the Treasury Department so the industry can deliver on the promise of the IRA. Storage was the one bright spot for the industry and had its second-best quarter on record. The aggressive deployment of storage continues to drive down consumer energy costs and enhance grid reliability."

Sandberg said the Inflation Reduction Act should be a major catalyst for the clean energy industry.

The American Clean Power Association reported Wednesday that U.S. construction of new clean energy projects slowed to the lowest rate in three years. | *Shutterstock*

"ACP anticipates that the IRA will give industry the tools it needs to more than triple annual installations of wind, solar, and battery storage by the end of the decade. We expect the IRA to deliver 550 GW of new capacity by 2030, representing $600 billion in capital investment and growing the clean power workforce to nearly a million strong by 2030."

Some highlights of the report:

- Between July and September, 4.6 GW of clean energy projects entered advanced development and 2.5 GW began construction. In total, 93 GW was in advanced development and 39 GW was under construction by the end of the quarter.
- Solar accounts for 63% of delays, wind 23% and battery storage 14%. Detained panel shipments are the biggest cause of delays for solar projects, and wind installations are most frequently hampered by supply chain disruptions and grid interconnection delays.
- Power purchase agreements for green energy totaled 7.2 GW for the third quarter, and the wind and solar market-averaged national price index reached a new high: $45.93 per MWh, 10% more than the previous quarter and 34% higher than a year earlier.
- Texas remains the leader in clean power, with 149.39 GW operational, 11.2 GW under construction, and 12.6 GW in advanced development, each metric the highest among the 50 states. Its third quarter installation total was 1.27 GW, second only to California's 1.4 GW. ■

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Southeast

Duke CEO: IRA Tax Credits Will Offset 15% Corporate Income Tax

Sale of Utility's Commercial Renewables Portfolio Expected by Mid-2023

By K Kaufmann

Duke Energy sees the U.S. clean energy transition — and clean energy tax credits from the Inflation Reduction Act — as providing growth and profit drivers for its regulated utility business, even as the company moves ahead with the sale of the 3.5-GW portfolio of its commercial renewable energy business.

Duke Energy CEO Lynn Good | *Duke Energy*

Speaking during the company's third-quarter earnings call Friday, CEO Lynn Good reported that Duke's board had authorized the sale of the utility's commercial and distributed renewable business. The sale will allow the company to focus on its "core" regulated electric and gas utilities, she said.

"We have indications of interest — robust indications of interest — from credible counterparties and have a high degree of confidence we will transact on this business," Good said. A "definitive" announcement could come in the first quarter of 2023, with the sale closing "as early as mid year," she said.

The commercial portfolio includes 1.53 GW of solar, 1.96 GW of onshore wind and 20 MW of battery story, according to company figures.

As previously announced during Duke's second-quarter earnings call, the proceeds from the sale will be used to pay down the utility's debt "and allow us to fund our clean energy transition," Good said. (See *Duke Considering Sale of 3.5-GW Portfolio*.)

The IRA's production and investment tax credits will also act as a counterweight to the law's 15% minimum corporate tax rate, which, Good said, is not expected "to have a material impact on our cash flows." According to utility estimates, Duke could be eligible for "several hundred million dollars" per year from the IRA's nuclear production tax credits, beginning in 2024.

Producing about half of the utility's electricity in the Carolinas, Duke's nuclear fleet includes 11 units totaling 10.7 GW of capacity, all located at six sites in the two states, according to the *company's website*.

Duke Energy expects its nuclear plants, like the 759-MW Robinson nuclear plant in South Carolina (above), could qualify for hundreds of millions of dollars from the Inflation Reduction Act's nuclear production tax credits. | *Duke Energy*

The utility is also estimating that the solar production tax credit will be worth about $60 million per year given the 13 to 17 GW that it could be putting on its system over the next decade. Potential investments in energy storage, estimated at $2.5 billion to $4.5 billion, would be eligible for the 30% investment tax credit for standalone storage, according to utility figures presented during the call.

Besides providing hefty tax write-offs, Good said the tax credits would be "returned to our customers, lowering our overall cost of service and providing for a more affordable energy transition."

Duke is also capitalizing on the growth of electricity demand from new clean technology manufacturing across its service territory. Good pointed to recent announcements, such as the multibillion-dollar semiconductor plant Wolfspeed is building in North Carolina, and BMW's expansion into electric vehicles and EV batteries in South Carolina.

Inflation, Supply Chains

With such positive business indicators, including ongoing population increases in its service territories, Good said the utility is projecting an earnings growth rate of 5 to 7% from 2023 to 2027.

The company reported net income of $1.356 billion ($1.78/share) for the quarter, compared to $1.435 billion ($1.88/share) for the same period last year.

Good acknowledged that Duke, like other businesses across the country, is facing headwinds in terms of both inflation and supply chain constraints. To counter inflation, the company has upped its cost-cutting efforts from $200 million to $300 million, Good said.

Responding to analysts' questions, she said the cuts will come from digitalization initiatives that will "streamline our governance processes and reporting processes." Duke is also "looking at supply chain and … other things that we could do to potentially move [costs] out of [20]23," she said.

At the same time, the utility is countering supply chain constraints via multiyear contracts with key vendors. "We have confidence around supply into [2026] and beyond, with options to

Southeast

continue. We're putting similar arrangements in place for battery storage," Good said.

Duke's long-term plan for the energy transition calls for $145 billion in capital investments over the next 10 years, with $75 billion earmarked for grid investments, $40 billion for "regulated zero-carbon generation" and $5 billion for "hydrogen capable" natural gas generation.

Carbon Plan Update

But Duke's regulatory landscape, particularly in North Carolina, is still uncertain as the utility works through its compliance with *H.B. 951*, passed in 2021, which requires the Utilities Commission to approve a plan that will cut the state's carbon emissions 70% by 2030. The commission asked Duke to draft the plan, which under the law must be approved by the end of the year.

Submitted in May, Duke's *draft plan* includes the closure of 4.9 GW of coal and the addition of 5.4 GW of solar, but also calls for 3.5 GW of new natural gas generation. The plan also includes alternative pathways to the 70% reduction that would take two to four years longer. (See *Duke Files Carbon-reduction Plan for North Carolina Utilities*.)

Environmental and clean energy groups and state Attorney General Josh Stein have roundly criticized Duke's plan and submitted alternatives of their own. But following recent series of public hearings, Duke filed a *proposed order* for the NCUC to approve its plan, and Good remains confident.

"This process is something that looks reasonable and somewhat predictable to us," she said Friday. "The solar industry is interested in more solar; the industrials are interested in low prices. Low-income [organizations] are interested in the impact to low-income [customers]. The attorney general and the environmental community want us to go as fast as we can to reduce carbon [emissions]."

Good said that the comments and testimony from such stakeholders provide "fertile ground for the commission to make decisions" and defended the company's approach.

"In the near term, it's all about solar and battery [storage], and we have time on the long term to make decisions about some of the more difficult [technologies]: pumped storage; [small modular nuclear reactors]; offshore wind. So, we think there is strength to our recommendation to use the next couple of years to look at development on those key technologies so that we're prepared by the middle of the decade to make the decisions about where to go."

In particular, Good said, the company is in "evaluation mode" on offshore wind.

"It's a renewable resource, but … we also recognize it's expensive. It has transmission requirements, especially here in the Carolinas where you've got to get the power to the load centers that are further west than the coast," she said. "The approach we're taking is one of studying and learning more and also allowing the commission and stakeholders and the communities that could be impacted by both offshore and onshore transmission to be involved.

"We will not move first, and we will not move outside of the regulated business," Good said. "The risk [versus] reward for investors and customers has to be appropriate for us to move forward." ■

CAISO/West News

Risk from Variable Resources Increasing, WECC Says

By Hudson Sangree

Reliability risks from the addition of variable resources to the Western grid will continue to grow, requiring greater planning reserve margins to mitigate the unpredictability of wind and solar generation, WECC said Wednesday in its third annual Western Assessment of Resource Adequacy.

Last year's Western assessment showed a planning reserve margin indicator (PRMI) for the Western Interconnection of 16.9%. The 2023 PRMI increased to 18.3% in WECC's latest *assessment*.

"Additional [variable energy resources] will cause the PRMI to increase further," WECC said. "If nothing is done to mitigate the long-term risks within the Western Interconnection, by 2025 we anticipate severe risks to the reliability and security of the interconnection."

Power producers plan to retire 26 GW of resources, mostly coal and natural gas plants, during the next decade and to add 80 GW of new resources, most of which will be solar and wind generation and battery storage.

"The resource mix in 2032 will look different than it does today, with much higher levels of variability," the assessment said. "This is because resources like solar and wind are variable, meaning their energy output changes constantly and there is limited dispatchability."

Severe weather events and rising temperatures add to the uncertainty, as do electrification, energy efficiency and emerging technologies, WECC said.

All "will affect how demand looks and behaves over the next decade," it said. "This added uncertainty exacerbates the challenges facing planners and operators."

WECC's other measure of resource adequacy, its demand-at-risk indicator (DRI), showed fewer hours at risk of electricity shortfalls in the next few years. WECC measures DRI for every hour of the year for five subregions: California and Mexico, the Desert Southwest and three regions — central, northwest and northeast — of the Western Power Pool (shown as NWPP in the report).

"Compared to the 2021 assessment, the DRI for the Western Interconnection decreases through 2025 due in part to reductions in the load forecasts in the Pacific Northwest and northern Rocky Mountains, and in part to actions taken after the 2020 heat wave to strengthen resource adequacy," it said.

"These actions include the addition of almost 3,000 MW of new or expedited resources, the vast majority of which is battery storage, and the delayed retirement of generator resources," WECC said.

The delayed retirements included the 2,300-MW coal-fired Jim Bridger Power Plant in Wyoming, the 1,600-MW gas-fired Haynes Generating Station in Long Beach, Calif., and the 830-MW gas-fired Scattergood Generating Station in Los Angeles.

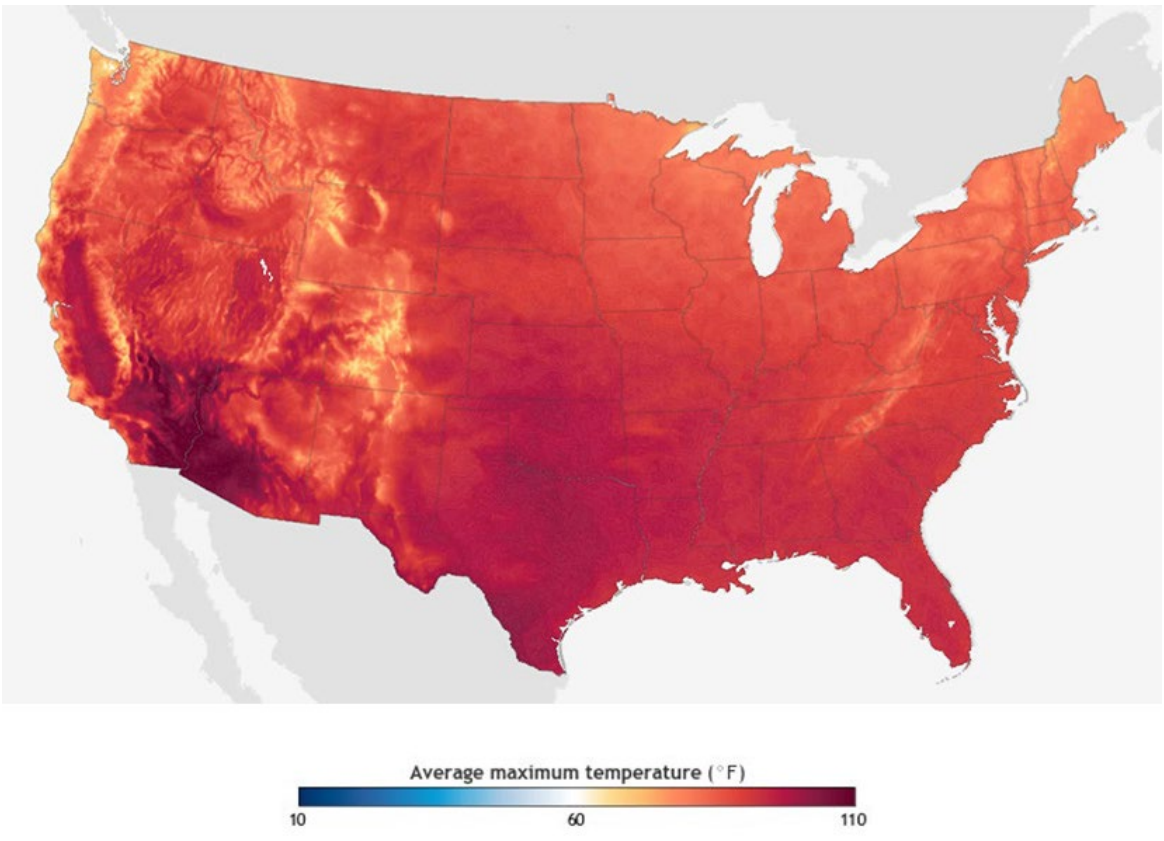
"Once these plants are retired, the risk returns and will need to be mitigated," WECC said. "Delaying the retirements provides entities more time to determine how to mitigate the risks once these plants retire."

After 2025, each WECC subregion shows an increase in DRI because of retirements in the next decade, the reliability organization said.

WECC introduced its Western RA assessment in 2020 to supplement NERC's Long-Term Reliability Assessment because Western stakeholders were concerned that NERC's analysis did not capture all the risks the Western Interconnection faces.

Like the NERC assessment, WECC's Western assessment attempts to identify the biggest threats to the bulk power system over the next 10 years.

WECC has scheduled two *webinars* to discuss its findings, a high-level policy overview this Wednesday and a "deep-dive technical review" on Nov. 16. ■



Daily temperatures are projected to increase from 2030-2039, impacting demand across the West, WECC said. | *NOAA*

CAISO/West News

CAISO Reports on Summer Heat Wave Performance

By Hudson Sangree

CAISO got through September's record-setting Western heatwave without blackouts by importing electricity, calling on the public to conserve energy and coordinating with utilities and government agencies, the ISO said in its 2022 Summer Market Performance Report published Wednesday.

During the 10-day stretch of triple-digit temperatures, from Aug. 31 to Sept. 9, CAISO experienced unprecedented demand, reaching a new high of more than 52 GW on Sept. 6. Demand in CAISO's Reliability Coordinator footprint, which covers much of the Western Interconnection, set a record at more than 130 GW.

"The heat wave of September 2022 was one of the most challenging events in the history of the ISO grid," CAISO CEO Elliot Mainzer said in a news release. "During events like these, it is important to carefully and transparently examine what went well and to identify issues to address and lessons learned that can be carried forward into future operations."

In the *report*, CAISO said new resources procured since the rolling blackouts of August 2020, when demand reached 46 GW, have bolstered reliability. The ISO's territory has added more than 3,500 MW of lithium-ion batteries in the past two years to store the ample solar power produced in the daytime in California.

Blackouts and near misses in the last three summers occurred during heat waves when solar power ramped down in the evening, but demand remained high from air conditioning use.

CAISO cited "enhanced coordination, awareness and communications internally and with neighboring balancing authority areas," including participants in the ISO's Western Energy Imbalance Market, as another reason it was able to keep the lights on. The increased coordination extended to investor- and publicly owned utilities, the California Public Utilities Commission, the state Energy Commission and the governor's office, it said.

Market enhancements enacted the past two years helped, too, the report said. CAISO has reworked its scheduling priorities, beefed up its resource sufficiency evaluations and adopted "market pricing designed to incentivize generation during periods of high demand," it said.

The major factor in avoiding blackouts on Sept. 6, the most strained day of the year, was an emergency text message sent out to 27 million cell phones by the Governor's Office of Emergency Services urging consumers to conserve electricity in the face of imminent blackouts.

When the text message went out at 5:45 p.m., CAISO already had declared a stage 3 energy emergency and told utilities to arm for load shed, but it had not given the final order to start rotating outages.

Demand fell by 2,385 MW in 20 minutes after the governor's Office of Emergency Services issued a text alert on Sept. 6 at 5:45 p.m. | *CAISO*

Within 20 minutes of the alert, demand plummeted by 2,385 MW, to 48 GW, narrowly avoiding blackouts.

Imports from the Pacific Northwest and parts of the Desert Southwest, where the heat was less extreme, also played a large role in maintaining grid reliability, CAISO said.

"This included net imports of more than 6,500 MW during net peak on September 6 as well as an additional 1,000 MW from WEIM transfers," the report said. "The ISO both received emergency assistance energy and provided it to other balancing authority areas experiencing stressed system conditions."

Average daily electricity prices soared to $600/MWh with prices topping $2,000/MWh in some parts of the state. In comparison, the average locational marginal price for September was $106 MWh, it said.

Lessons Learned

The ISO said it learned lessons from the crisis that included the need to improve the use of batteries in the real-time and day-ahead time frames to optimize dispatch and ensure they are used most effectively in heat waves.

"The high prices experienced during the heat wave presented new scenarios for the ISO to learn about the complexities and challenges of managing battery state-of-charge," the report said.

Batteries that bid above $150/MWh to charge during the day were insufficiently charged when they were needed at nightfall because of a software glitch, CAISO said.

"Despite this, ISO operators were able to position storage resources during the September 2022 heat event to meet net-peak requirements by leveraging minimum state-of-charge market functionality that was implemented as part of a package of 2021 summer readiness enhancements," it said. "The ISO has now fixed the software issue."

Another software problem "unintentionally curtailed higher-priority exports … while allowing lower-priority exports to flow," CAISO said. "Although the ISO largely caught and reversed the error in high-priority curtailments, it deployed a software upgrade on Oct. 13 to ensure the appropriate export curtailment order is followed going forward."

In addition, there was under- and over-counting of capacity in the WEIM's resource sufficiency evaluation that resulted in CAISO failing the test two times on Sept. 6 instead of the six times it should have failed, the report said.

Because of the counting errors, "transfers into the ISO were limited, but not material," it said. "This is because the transfer limits were well above the actual available transfers of 1,000 MW from the WEIM, so transfers into the ISO were not restricted."

CAISO said it has corrected some of the counting problems and is exploring additional fixes.

The ISO has scheduled a *stakeholder call* for Nov. 17 to review the analysis and answer questions. ■

CAISO/West News

WEIM Q3 Benefits Top $500M, Near $3B Total

By Hudson Sangree

Participants in CAISO's Western Energy Imbalance Market saw a record $526 million in benefits in the third quarter of 2022 as the market approached $3 billion in total benefits, six months after it passed the $2 billion mark.

The results outstripped the next highest quarter, Q3 2021, by $225 million. The new record was the result of more participants in the interstate WEIM and "economical transfers displacing more expensive generation," especially during September's Western heat wave, CAISO said in its third-quarter *report* Oct. 31.

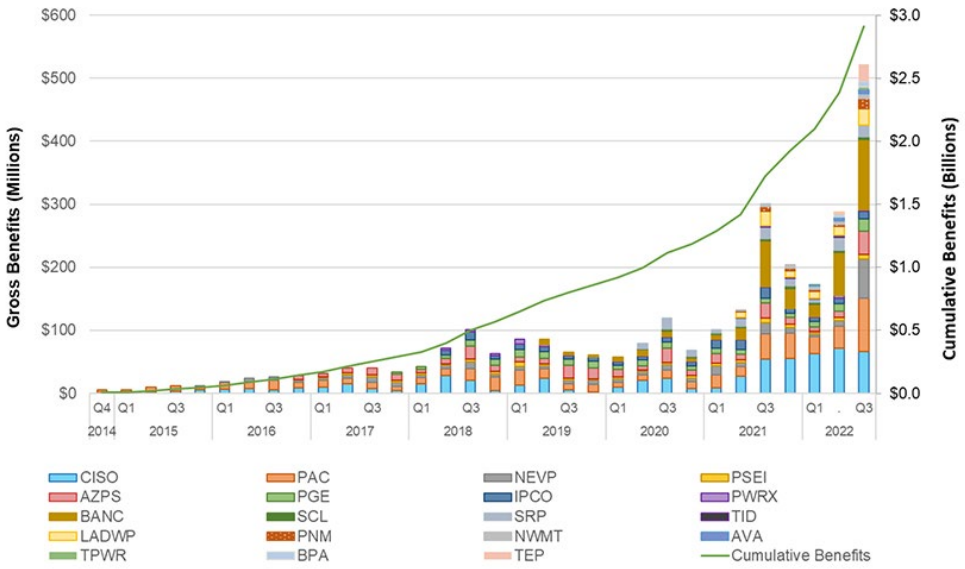
"Resource sharing among WEIM participants during this summer's extraordinary 10-day heat wave provided meaningful economic benefits while helping maintain reliability for millions of consumers in the West," Stacey Crowley, CAISO vice president of external affairs, said in a news release.

The Balancing Authority of Northern California (BANC) had more than $111 million in benefits in Q3. BANC consists of inland areas where temperatures set records in September. One BANC member, Sacramento Municipal Utility District, warned customers of potential outages as the high hit 116 degrees Fahrenheit in Sacramento on Sept. 6.

Other BANC members, such as Modesto Irrigation District and Turlock Irrigation District, also dealt with record-high temperatures and soaring demand.

PacifiCorp obtained $84.5 million in benefits last quarter, while CAISO saw $66 million in benefits. Other large beneficiaries included Southwest utilities NV Energy ($62 million), Arizona Public Service ($36 million) and Tucson Electric Power ($27 million).

The third quarter was the first full quarter of WEIM participation for Tucson Electric Power and the Bonneville Power Administration, which obtained a bit more than $9 million in benefits.



WEIM third-quarter benefits exceeded prior quarters and brought cumulative benefits close to $3 billion. | *CAISO*

With 19 participants, the WEIM "finds and delivers the lowest-cost resources to meet immediate power needs and manages congestion on transmission lines to maintain grid reliability," the news release said.

CAISO expects the WEIM to encompass 80% of load in the Western Interconnection by next year, after the entry of new participants El Paso Electric Co. and the Western Area Power Administration's Desert Southwest Region.

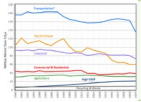
Since WEIM began operations in November 2014, its cumulative economic benefits have totaled $2.91 billion, the ISO said.

"The measured benefits of participation in the WEIM include cost savings, increased integration of renewable energy, and improved operational efficiencies, including the reduction of the need for real-time flexible reserves," CAISO said in its quarterly report.

WEIM surpassed $2 billion in cumulative benefits in Q1 2022, 20 months after it reached $1 billion in total benefits. The entry of new participants accelerated and compounded the market's overall benefits, the ISO said at the time.

CAISO has cited the economic benefits of the real-time WEIM as reason for utilities to join its proposed expanded day-ahead market (EDAM), which it hopes to bring before its board of governors and the WEIM's Governing Body in December. ■

West news from our other channels



Pandemic Brings 'Historic' Decline to Calif. GHGs in 2020

NetZero Insider

Multiple Seaports Needed to Support Calif. OSW Goals

NetZero Insider

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ERCOT News

ERCOT Stakeholders Wait on Bylaw Amendment Changes

TAC Approves Annual Review

By Tom Kleckner

ERCOT stakeholders have submitted comments on proposed amendments to the grid operator's bylaws that have been sitting with the Board of Directors since September.

The *amendments*, drafted by staff at the board's direction, would no longer require members' approval of such changes. It would require that members be provided notice and the chance to comment on any proposed amendments or other "fundamental actions."

Members had until Sept. 30 to comment on the revisions. The board was to discuss the amendments during its October meeting but did not do so in a public forum.

Jupiter Power's Caitlin Smith filed comments on behalf of 26 other members , saying it is "imperative to emphasize the chilling effect the proposed amendments could have on decisions to enhance and maintain the health and reliability of the ERCOT grid, including continued investment in generation."

"A successful energy-only market requires that its participants have a vested interest in the activities of the organization," Smith said, referring to the development and refinement of market policy and rules.

"Corporate members must vote to amend the ERCOT bylaws," she said. "Eliminating this right of ERCOT stakeholders is a clear signal to investors of regulatory and market uncertainty, which sends a negative investment signal that, all else equal, will impact operations, reliability and the provision of energy to consumers within the state."

Smith said that if the proposed amendments are adopted, ERCOT's governance structure will "most closely resemble" CAISO's.

ERCOT Assistant General Counsel Jonathan Levine was unable to clarify the board's next steps on the amendments during the Technical Advisory Committee's short, virtual meeting Oct. 26.

"It's a pretty fluid situation at this point. It's up to the board and the board chair of what they want to do," he said. "I apologize for not having any better information about where we're heading on the bylaws amendment. I'm just a mouthpiece here."

The Protocol Revision Subcommittee said it is working on a priority revision process that TAC shared with the board's Reliability and Markets Committee in October. A draft will be presented during TAC's Dec. 5 meeting. (See "TAC Shares Changes with R&M," *ERCOT Board of Directors Briefs: Oct. 18, 2022*.)

Caitlin Smith, Jupiter Power, during a recent panel discussion. | © *RTO Insider LLC*

Combo Ballot Approves TAC's Annual Review

TAC's combination ballot last month included the results of its *annual structural and procedural review*, two nodal protocol revision requests (NPRRs), a revision to the Load Profiling Guide (LPGRR), an other binding document request (OBDRR) and a change to the Retail Market Guide:

- *NPRR1128*: would set a 1-cent/MW lower ancillary service (AS) offer floor for fast frequency response (FFR) responsive reserve (RRS), thereby allowing, depending on relative AS offers, FFR procurement up to the current limit without proration with other RRS categories in the ancillary procurement process.
- *NPRR1148*: would resolve protocol gaps found during emergency contingency reserve service's creation of its system change requirements.
- *LPGRR069*: would add Lubbock Power & Light's service address zip codes to the guide and updates the ERCOT service territory map to include Lubbock County. The LPRR also corrects zip code counts that were omitted in the count column.
- *OBDRR043*: would align the operating reserve demand curve's methodology with NPRR1148.
- *RMGRR170*: would define the inadvertent gain/loss (IAG) process and an IAG; clarify its appropriate use; and clarify the IAG process' appropriate use. ■

ERCOT News

Vistra's Generation Produces During Texas Summer

Vistra said its generation fleet provided 96% commercial availability during Texas' record-breaking summer, helping smooth the volatility of fuel prices, weather and rising inflation.

CEO Jim Burke told financial analysts during the company's third-quarter earnings call Friday that its thermal fleet reached maximum capacity on July 13, when wholesale prices reached the $5,000/MWh cap three times.

"A well maintained fleet is key to delivering reliable power for our customers and our communities and ensuring value is captured during these weather events," Burke said.

Vistra *reported* quarterly earnings of $1.04 billion as measured by adjusted EBITDA from ongoing operations, as compared to $1.19 billion for 2021's third quarter. The company uses adjusted EBITDA as a performance measure because, it says, outside analysis of its business is improved by visibility into both net income prepared in accordance with GAAP and adjusted EBITDA.

Burke said management has been pleased with how its Vistra Zero assets performed this summer in Texas and California. It is attempting to *extend by 20 years* the operating licenses at generation subsidiary Luminant's Comanche Peak Nuclear Power Plan. That would keep the 2.4-GW plant's two units operating until 2050 and 2053.

"We continue to see how important a role our diverse set of assets are playing throughout the U.S. and ensuring reliable, affordable and sustainable power," he said.

The Irving, Texas-based company said its full-year results are tracking at the midpoint of their $2.96 billion to $3.16 billion guidance. It is amid an upsized $3.25 billion share repurchase program, having bought back about $2.05 billion in outstanding shares (18%) as of Nov. 2.

Vistra's share price lost 40 cents on Friday, closing at $22.85. ■

— Tom Kleckner

Vistra is attempting to re-license its two nuclear units at Comanche Peaks into the second half of this century. | *Vistra*

ERCOT News

Texas PUC's Proposed ERCOT Market Design to be Released Soon

Commission's Solutions Expected to Favor Dispatchable Generation

By Tom Kleckner

AUSTIN, Texas — Keynoting the Energy Bar Association Texas Chapter's Energy Symposium last week, Lori Cobos, the only lawyer sitting on the state's Public Utility Commission, said ERCOT stakeholders will soon get a look at the market's long-awaited redesign.

"Around Nov. 10," a consulting firm will release its review of the PUC's market redesign blueprint, Cobos said, which the commission agreed to almost a year ago. The PUC has since added an open meeting to its calendar for that date. A spokesman confirmed the commissioners plan to take up and discuss the consultant's report and recommendation.

Expect the recommendations to be heavy on dispatchable generation, which includes the usual thermal resources and energy storage. Since the February 2021 winter storm crippled ERCOT's system, the PUC, ERCOT and Texas legislators have prioritized baseload generation over renewable resources. (See *PUC Forges Ahead with ERCOT Market Redesign*.)

"If Texas is to continue to lead the country as an economic powerhouse, that will require a reliable, resilient and affordable supply of power to fuel our economy and serve our growing population base," Cobos said during the symposium Nov. 1. "Texas must maintain year-round reliability under all weather conditions, and to do this, we will need to drive investment in new and existing dispatchable generation through market-based price signals and a reliability-driven framework."

She said the market must incentivize "fast-responding dispatchable generation" that can respond to wind's and solar's variability and retain the existing baseload generation "that is available 24/7 to meet our continuously growing electricity demand and extreme weather conditions."

A load-side reliability mechanism, proposed in a study funded by generation heavyweights NRG Energy and Exelon, is expected to be the central recommendation. Referred to as the load-serving entity obligation (LSEO), the study's authors have said it will directly address resource adequacy concerns by introducing a formal reliability standard and the mechanism to ensure an LRE has sufficient resources to meet this standard.

PUC Chair Peter Lake quickly latched onto the LSEO proposal late last year. The other commissioners at the time offered some pushback but agreed to include it on the new market blueprint.

Moderator Michael Tomsu (far right), a partner with Vison & Elkins, introduces his panel during EBA's Texas Energy Symposium (from left): Alison Silverstein, Silverstein Consulting; Todd Staples, Texas Oil & Gas Association; Bill Barnes, NRG Energy; and Liz Jones, Oncor. | *© RTO Insider LLC*

Indirectly responding to criticism from some that the LSEO would be a "capacity-light" market, NRG's Bill Barnes, senior director of regulatory affairs, said, "People think, 'Oh, NRG, they just want a capacity market.' No, we want a competitive market that can survive through reliability events, so that we can preserve our successful market structure. That's the No. 1 priority for us."

Barnes did not mention that the consultant reviewing the PUC's blueprint, E3 Consulting, is the same firm that produced the NRG-Exelon report. The commission chose E3 over ERCOT's Independent Market Monitor, the only other bidder on the *contract*.

Alison Silverstein, Silverstein Consulting | *© RTO Insider LLC*

Energy consultant Alison Silverstein, a former PUC and FERC staffer, has worked with the Texas Consumer Association (TCA) and ICF International, a global consulting services firm, to produce an analysis on the cost and reliability impacts of ERCOT's recent and proposed market changes. She said deep concern over "a teeny bit of bias and conflict of interest" of E3's ability to fairly review the PUC's proposal led to their own analysis.

"The PUC hired E3, apparently untroubled by that same concern, and E3 went off and did the study, and nobody's heard anything," Silverstein said, speaking on the same panel with Barnes.

The commission's blueprint also includes a backstop reliability service (BRS) and the use of dispatchable energy credits (DECs).

BRS would procure accredited new and existing dispatchable resources as an insurance policy to help prevent emergency conditions. Its principles include nonperformance penalties and clawbacks for noncompliance; deploying resources in a manner that doesn't negatively affect real-time energy prices; and allocating costs to load based on a load-ratio share basis measured on a coincident net-peak interval basis.

The DEC proposal would establish a dispatchable portfolio standard for certain qualifying generators to create the DECs, which would be bought, sold or traded is the same manner as ERCOT's existing renewable energy credit program.

"Does our market structure provide the right incentives for reliability?" Barnes asked, referring to the market design discussions. "It's efficient. It's cost efficient; brutally efficient. So, you're getting the lowest-cost solution out of our current market design, but that doesn't always mean reliability."

ERCOT News

Cobos assured her EBA audience that the commission will take public comment before making a final decision in January. She said the Texas Legislature, which begins its 2023 session on Jan. 10 and runs through Memorial Day, will also provide feedback on the blueprint, "in addition to looking at investments in dispatchable generation."

PUC's Market Design Costs

The PUC "had three primary options that have been sitting around, and to date, there has been minimal information released about what the specifics of those proposals were, or what the design and cost and reliability implications of those would be," Silverstein said.

ICF *analyzed* the proposed designs using available public information and various models. Based on that, it said none of the current proposals would, by themselves, improve reliability enough to yield one outage every 10 years, the industry's generally accepted standard of 0.1 loss-of-load expectation (LOLE).

"We thought it was a very reasonable set of assumptions and scenarios and methodology," Silverstein said.

Texans should expect, on average, about five outages every 10 years (a 0.5 LOLE), ICF said. It noted reliability is expected to further deteriorate by 2030 if no further policy measures are taken.

Calling the LSEO proposal a "California-style redesign" of the ERCOT market, in that consumers would pay more for power plants that might not operate, ICF's study found it would cost Texans an additional $22.8 billion from 2025 to 2030, including $8.5 billion more in 2025 alone, without significantly increasing the grid's reliability. It forecast the LSEO would add another 2.5 GW of gas generation by 2030.

ICF said the BRS proposal, based on an energy storage entity's recommendation, would yield less than two outages a decade (0.17 LOLE) at a total cost of $2.6 billion from 2025 to 2030. It projected the BRS would also retain about 8 GW of capacity that would otherwise retire under the current market construct.

The DEC proposal would cost consumers $1.3 billion during its first three years (2023-2025) but would then reduce the total costs to consumers by approximately $2 billion each year from 2027 to 2030, ICF said. It forecasts DEC, based on an energy storage provider's recommendation, to bring online 3.4 GW of additional two-hour battery storage by 2030.

"Yes, there's a wide range of uncertainty around LSEO cost," Silverstein said during an Oct. 26 virtual press conference unveiling the study. "The one thing that is not uncertain, that is absolutely clear, is the LSEO costs are potentially huge. And as of now, the program is so significantly undefined that there is no way to narrow in the parameter for how expensive it could be or how effective it could be at improving reliability.

"Texans need a reliable grid, but not at any cost," she said.

New Study on Energy Efficiency, DR

TCA plans to release a companion report later this month comparing the cost and reliability effects of using high levels of demand-side resources to improve reliability, with the results contrasted with its supply-side analysis.

Silverstein called it a follow-up, parallel piece to "the one scenario that the PUC chose not to study."

"What happens if we actually do what customers do a lot more of with energy efficiency and demand-responsive distributed assets?" she said. "What does that do for reliability and affordability in ERCOT?"

Silverstein said Texas energy efficiency requirements are tied for last among the 28 states with such requirements. "We deliver such minimal energy efficiency to so few Texans, it's criminal," she said.

Liz Jones, Oncor | *© RTO Insider LLC*

Liz Jones, Oncor's vice president of regulatory affairs, said she expects energy efficiency to be one of the key issues debated within the legislature next year.

"There is a cottage industry about what kinds of programs are effective and efficiently implemented," Jones said. "There is always a struggle because when we undertake energy-efficiency measures, we are collecting funds from all customers, and we are dispersing them to the customers who are qualified for the energy efficiency. It turns out it takes a lot of money to weatherize. Is it crucial for the person that lives in that home? Yes, and so we're going to see a fight, I think, at the legislature about how we spend on energy efficiency."

"The programs today are all over the map. They are not always focused, and they are tiny," Silverstein said, agreeing with Jones. "The reason the winter storm caused so much damage is because Texas homes are under-insulated, because Texas heaters are ineffective and because the energy demand before the power started going out was 20% above anything that ERCOT had forecast. That was because of a lack of energy-efficient homes and lack of energy-efficient heaters. We deserve better, both for winter and for summer."

Market Provides Expert Feedback

Jones and NRG's Barnes both said market participants need to have a greater role in the rulemaking process. They and other ERCOT participants have seen their input sharply reduced with *Senate Bill 2*, which passed by last year's 87th Legislature. The legislation created an independent board at ERCOT and gave more accountability to the PUC.

"One of the issues is how much should market participants — like Oncor; like NRG; like the city of Austin — have in making ERCOT rules. I would contend that you need us," Jones said. "First of all, we're free labor. We can provide feedback about how a particular rule would or would not be able to be effectuated in real-time operations or in planning. One of the things that I'm personally very interested in is making sure that the ERCOT rulemaking process, like the PUC rulemaking process, incorporates the feedback of interested parties in making those rules. It's procedural due process, substantive due process. It's a sensible way to try to do this."

"I completely agree with Liz's comments on Senate Bill 2," Barnes said. "As a stakeholder in a marketplace, we have a stake in it. We have invested a lot of money [and] people time, and we should have a voice. Our folks are the experts. They're the ones that turn the wrenches to start the power plants, and ERCOT needs to hear from us."

Barnes added that he hopes the legislature avoids "tinkering" with market rules that have already passed. He pointed to the PUC's weatherization requirements for power plants and transmission facilities as an example of changes that have already been instituted and that work.

"We like to have rules that are predictable and are certain to be done," he said. "It would be great for the legislature to let that process play out, but they're not going to. I would hope that there will be a lot of robust debate and discussion at the legislature, but let's let the process play out at the PUC where the experts are. It will take time. It's not like we're going to be to snap our fingers and have an answer. These things are complicated, and we want to make sure we get them right." ■

ERCOT News

Texas PUC Briefs

ERCOT to Add Reliability Monitor to its Responsibilities

The Texas Public Utility Commission last week approved staff's recommendation that ERCOT serve as the footprint's reliability monitor, formalizing a two-year collaboration that has resulted in several enforcement investigations (*54248*).

The commission agreed to *direct* ERCOT to assume the reliability monitor duties and responsibilities as part of the consent agenda during its open meeting Thursday. With Chair Peter Lake out on personal leave, Commissioner Will McAdams led the meeting.

PUC staff said ERCOT has for years adopted reliability-related regulations that are found in the organization's nodal protocols, operating guides and other binding documents. For the past two years, it has worked with the commission's Division of Compliance & Enforcement to jointly monitor and investigate potential noncompliance with the grid operator's reliability rules.

As the reliability monitor, ERCOT will gather and analyze data; protect confidential information; provide expert advice to commission staff during the investigation, prosecution and litigation of reliability-related enforcement proceedings; and work under the PUC's direction.

A spokesperson said the grid operator will need additional staff to perform the monitor's duties. Its budget will be funded through the system administration fee that has historically included the function's costs, she said. ERCOT staff will begin performing the function "immediately."

The Texas Regional Entity had served as the grid's reliability monitor from 2010 until 2020. The PUC ended its contract with the agency over concerns it wasn't getting its money's worth. (See *PUC Cancels Texas RE as ERCOT's Reliability Monitor*.)

The Texas RE enforces NERC's federal reliability and security regulations, which are subject to FERC oversight, in the state. Most entities operating on the transmission system in the ERCOT region are subject to NERC's standards.

The state's Public Utility Regulatory Act requires the PUC to adopt and enforce rules related to ERCOT's reliable operation of the region's system. It also allows the commission to delegate the responsibility for adopting or enforcing these rules to an independent organization.

Will McAdams (right), alongside commissioner Jimmy Glotfelty, chairs the PUC's Nov. 3 open meeting. | *Admin Monitor*

ENGIE Case Set for Hearing

The commission approved in part and denied in part ENGIE's and Viridity Energy Solutions' complaint against ERCOT regarding the settlement of ancillary services during the February 2021 winter storm (*53377*).

The PUC approved a *preliminary order* that sets issues to be addressed, but it denied ENGIE's request to depose commission staff. It also denied its staff's request for a protective order from providing depositions as being too broad.

"The commission can't be deposed, given our quasi-judicial role in this matter," Commissioner Lori Cobos said. She said ENGIE could request to depose specific commission staff by name as fact witnesses, making staff's request too broad.

Commissioner Lori Cobos | *Admin Monitor*

The companies allege that the grid operator did not properly credit Viridity for providing responsive reserve service (RRS) during the storm and that ENGIE was assessed $47.7 million in charges for replacement RRS. They argue that Viridity should be credited $67.4 million to $140.6 million for providing RRS and that ENGIE should not be charged for the replacement service.

The commission referred the docket to the State Office of Administrative Hearings (SOAH) to conduct a hearing and issue a proposal for decision to resolve any contested issues.

Entergy Power Plant not Considered

The PUC did not take up Entergy Texas' application to construct its 1.22-GW Orange County Advanced Power Station in Southeast Texas, despite an *administrative law judge's approval* of the project (*52487*).

The ALJ in September recommended the project's approval but removed a hydrogen component and imposed a cost cap. The project's costs have already risen from $1.19 billion to $1.58 billion in a year. Entergy's plans the facility to be able to burn 30% hydrogen upon commercial operation and eventually support 100% hydrogen operation.

"We continue to believe that Day 1 hydrogen co-firing capability for [the facility] is in the best interest of our customers," Entergy CEO Drew Marsh said during the utility's third-quarter analysts call Nov. 2. (See related story, *Entergy Learning from Florida to Improve Resilience*.) He noted that Texas Gov. Greg Abbott

ERCOT News

has "indicated" his support for the plant's hydrogen capability.

"Capped hydrogen capability is less than 5% of the total investment, and it provides a critically important option for fuel diversity and ensures the plant's continued value at the low-carbon future," Marsh said.

PUC Adds OK to ADER Pilot Project

The commission formally approved ERCOT's Aggregate Distributed Energy Resource (ADER) pilot project, which was also approved last month by the grid operator's Board of Directors (*53911*). (See *ERCOT Board of Directors Briefs: Oct. 18, 2022*.)

The project will evaluate how ADERs can support reliability, participate in the wholesale market and play a role in emergency situations.

"This is a victory for the stakeholder process all the way around, from the commission to ERCOT staff to the industry stakeholders to the average everyday consumers who were able to participate," said McAdams, who spearheaded PUC's involvement in the project with Commissioner Jimmy Glotfelty. "Big things have small beginnings, and I think this is going to be a big thing."

"I think that this puts us in a driver's seat of leading again. ... We're going to learn a lot from this," Glotfelty said.

In other actions, the PUC:

- denied El Paso Electric's rehearing request to correct an error in one of its rate schedules. The utility filed an uncontested settlement with other parties to the proceeding in July that was approved by an administrative law judge in September (*52195*).
- assessed a $72,000 administrative penalty to South Texas Electric Cooperative for failing to telemeter the appropriate resource status code and for failing to timely and properly assign its ancillary service capacity obligation in 2019 (*53691*).
- agreed to open an investigation into Texas Excel Property Management for possible violations related to the denial of tenants' rights to choose a retail electric provider in ERCOT's footprint where retail customer choice has been introduced (*54225*).

— Tom Kleckner

ISO-NE News

ISO-NE Gets an Earful at its First Public Board Meeting

By Sam Mintz

PROVIDENCE, R.I. — ISO-NE's Board of Directors had the rare experience of staring public criticism in the face on Nov. 1 as the grid operator held its first open board meeting at a Renaissance Hotel.

A series of speakers offering public comments came up one by one, addressed the board and told them what they think ISO-NE is doing wrong.

Most of the roughly 15 commenters were there to push ISO-NE to transition more quickly off fossil fuels and take the climate crisis seriously.

The meeting came about as part of a set of governance changes the grid operator is making to appease the New England states, which have been pushing for it to become more transparent and accessible. (See *ISO-NE Offers up Governance Tweaks*.)

One of the most attention-grabbing comments came from Kendra Ford, a Unitarian Universalist minister from Exeter, N.H., who walked to the microphone and looked into the eyes of each of the board members before speaking.

"We are in an emergency, and you are not acting like this is an emergency. We have to rearrange and reorganize the way we think about everything. Energy is at the leading edge of that," Ford told the board.

"You have done some things, but you need to do so much more, and you need to do it immediately to save lives," she said.

Later, as the board continued its largely standard business with an update from ISO-NE CEO Gordon van Welie, Ford stood up again and cut in.

"You're describing a carefully measured, convenient transition that doesn't inconvenience anyone and doesn't cause anyone to lose money. That can no longer be the way," she said. "I am begging you to respond to the emergency. It may not be affecting you personally in this moment, but it is coming to all of us."

Another commenter, Jonas Kaplan-Bucciarelli, a Boston University student from Amherst, Mass., asked the board to walk a mile in his shoes.

"I think that you don't understand the level of urgency and despair around the climate crisis, especially that my generation is experiencing as we're growing up in this world, and grew up having climate change on the radar as we were going through middle school and elementary school," he said.

Many of the commenters spoke out against the region's minimum offer price rule, which ISO-NE is phasing out instead of immediately removing, to the frustration of climate advocates in the region.

They also took ISO-NE to task for a stakeholder process that's widely seen as the least accessible of any grid operator in the country.

"It's been a struggle to engage with you all," said Amanda Nash, an activist with No Coal No Gas and 350 Massachusetts.

"You are all well trained and paid to create and administrate these procedures, but for the vast majority of us, this is work we do on top of our jobs and other responsibilities," Nash said. "It seems like obfuscation is the name of the game."

ISO-NE board members (from left) Caren Anders, Cheryl LaFleur and Gordon van Welie | © *RTO Insider LLC*

ISO-NE COO Vamsi Chadalavada offered a response to the commenters later in the meeting.

"The passion and urgency that we heard is unmistakable," he said. "But I also wanted to offer some comfort that that's the same level of urgency that all of us at the ISO feel in making sure we get through the clean energy transition.

"I didn't want to leave you with an impression that we are pro-fossil. … We are equally motivated to move towards the future," Chadalavada said.

And he urged people to reach out to the RTO for information and to answer questions, technical or otherwise.

At the meeting, van Welie gave a presentation on the organization's strategic plan, and the grid operator's managers also updated the board on market projects, energy adequacy and winter planning. And MIT Energy Initiative Director Robert Armstrong gave a presentation to the board on the future of energy storage. ■

ISO-NE News

NEPOOL Splits with ISO-NE over Pumped Storage Eligibility for IEP

By Sam Mintz

ISO-NE will not incorporate an amendment approved by the NEPOOL Participants Committee to include pumped storage resources in its Inventoried Energy Program, yet another wrinkle into the implementation of the chronically uncertain winter fuel security program.

The D.C. Circuit Court of Appeals in June ordered FERC and ISO-NE to narrow the eligibility of the program, removing certain resources — including hydroelectric — that the court found would benefit from the IEP without any functional change to their behavior. (See *Court Strikes a Blow to ISO-NE Winter Plan*.)

ISO-NE has moved to comply with that order by preparing a filing to send to FERC for consideration.

But Brookfield Renewable Partners appealed to the PC during its Wednesday meeting to allow pumped storage to remain eligible for the program, arguing that the technology shouldn't be ruled out.

Brookfield operates the 633-MW Bear Swamp pumped storage facility in Western Massachusetts.

"Brookfield's view is that when the court ruled to remove hydroelectric resources, it contemplated conventional hydro with pondage but did not contemplate pumped storage hydro operating as storage (i.e., daily pump/charge to generate/discharge)," Aleks Mitreski, the company's senior director of regulatory affairs, said in a *presentation* to the PC.

The economic rationale for when to operate pumped storage hydro and a chemical battery resource, for example, is identical, he argued; either all storage should be allowed to participate, or none.

The PC voted to approve Brookfield's amendment to the ISO-NE compliance filing, which would simply specify that pumped storage is allowed to participate in the IEP. But ISO-NE will ultimately not include the amendment in its filing, the grid operator said.

"We believe the directive from FERC was clear that hydroelectric resources are not eligible under this program, and our filing will adhere to that directive," ISO-NE spokesperson Matt Kakley said in an email to *RTO Insider*. "That being said, we welcome FERC's resolution on this issue and will be prepared to implement the program in accordance with the commission's ruling."

The filing isn't eligible for "jump ball" filings, which would formally pit ISO-NE's stance against NEPOOL's. Instead, NEPOOL will file comments to FERC explaining the votes shortly after ISO-NE submits its filing, according to NEPOOL counsel.

Brookfield has estimated that the additional cost to the IEP of inserting pumped storage back into eligibility is about $1.5 million.

Other PC Action

The committee briefly discussed a *proposal* to raise the age limit for members of the ISO-NE Board of Directors to 75, but it ultimately tabled it for further consideration at its next meeting in December.

It did approve the Hydro-Québec interconnection capability credit and installed capacity revenue values for the upcoming annual reconfiguration auctions.

It also approved by voice vote conforming changes to ISO-NE's Financial Assurance and billing policies to reflect the implementation of the IEP.

Finally it rejected a request for a waiver of the NEPOOL Generation Information System Operating Rules by NuPower Cherry Street, which has been trying to get corrected renewable energy certificates for February and March of this year. ■

Brookfield Renewable's Bear Swamp hydro project | *State of Massachusetts*

MISO News

DTE Unveils Renewable Energy Plan, Speeds Up Ending Coal Use

By John Lindstrom

DTE Energy unveiled its latest proposed integrated resource plan Thursday, pledging to end its use of coal by 2035 and go carbon free by 2050.

The utility's proposed "Clean Vision Plan," released in a 141-page *report*, also calls for DTE to boost its renewable energy generation to 60% by 2040, as promised at its most recent earnings call. (See *DTE Energy Pledges Fast-tracked Energy Transition*.) CEO Jerry Norcia also said the plan would invest $9 billion into the Detroit area's economy over the next 10 years.

Under the proposal, DTE will significantly increase its electric storage capacity to 1,800 MW.

DTE, the electric generating source for 2.3 million people and businesses in Detroit, unveiled the plan about five months after Michigan's Public Service Commission approved a similar IRP for CMS Energy.

DTE released its plan shortly after the PSC revised the parameters of IRPs in line with the state's MI Healthy Climate Plan.

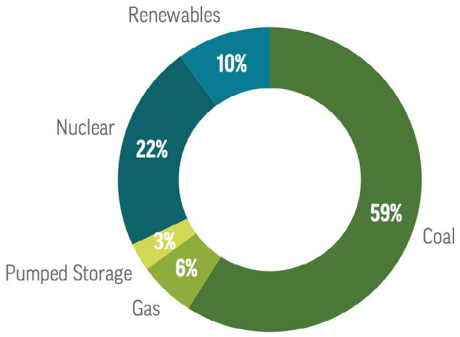
Norcia said across the U.S. and Michigan the energy landscape is changing "as coal gives way to natural gas and renewables to power what we call the modern grid."

Norcia said DTE intended to cut carbon emissions by 32% in 2023, two years ahead of a similar statewide goal in the state's MI Healthy Climate Plan. Carbon emissions would be further slashed by 85% by 2035 and 90% by 2040. In 2017, DTE had called for cutting carbon emissions by 80% in 2050.

Now, the DTE plan calls for eliminating carbon emissions by 2050, the deadline set in the Healthy Climate Plan.

In cutting carbon emissions, DTE plans to end coal use at the Belle River Power Plant by 2026 and repurpose it to run on natural gas.

The Monroe Power Plant, one of the largest coal-fired generators in the U.S., will close by 2028. | *DTE Energy*



DTE's current generation mix | *DTE Energy*

The 3,280-MW Monroe Power Plant, one of the largest coal-fired generators in the U.S., will close by 2028. The closure could affect the southern Michigan city's economy. The Monroe harbor, which has handled coal for the power plant as one its major commodities, has received an $11 million federal grant to help convert part of its piers along Lake Erie to handle wind turbine components.

DTE *said* it will provide retraining for plant workers and "partner with the local communities."

DTE's plan calls for increasing renewable energy production to 15,000 MW by 2042. Renewables currently represent only 10% of the company's 11,840-MW system capacity, with coal representing 59% and nuclear 22%.

Bob Allison, deputy director of the Michigan League of Conservation Voters, said DTE was falling short in what it should achieve. Blasting DTE for its electric rates and its struggles with power outages during major storms, Allison said, "We are at a pivotal moment in our state's clean energy future, and DTE must meet the moment with more ambition."

Reacting to the criticism, DTE spokesperson Cindy Hecht said, "In preparing our Integrated Resource Plan, DTE Electric undertook a year-long, comprehensive analysis that reflected insights shared by the company's customers and other stakeholders to build the plan, and we look forward to continued collaboration." ■

Northeast news from our other channels

Mass. Rejects Request for Delay on Offshore Wind Review

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MISO News

MISO's $4B MTEP 22 Clears 1st Board Vote Despite Criticisms

By Amanda Durish Cook

MISO's 2022 transmission planning portfolio cleared its first vote before the Board of Directors, though some stakeholders have lodged complaints over the package.

During a teleconference Nov. 1, the board's System Planning Committee voted unanimously to send the $4.3 billion, 382-project 2022 Transmission Expansion Plan (MTEP 22) to a full board vote in early December.

MTEP 22 earned just four votes in favor of recommendation and five abstentions from MISO's 11 stakeholder sectors. (See *Stakeholders Endorse MISO's Final MTEP 22*.) The Transmission Developers sector voiced complaints over a lack of a meaningful project alternative process, while the Environmental sector said MTEP planning cycles need to incorporate more preparation for grid-enhancing technologies, increasingly common extreme weather events and advance notice when transmission owners' age and condition projects are going to come due.

The Environmental sector also said it had concerns over MISO's wording in MTEP 22 that carbon-reduction goals alone are driving the footprint's resource transition and that gas generation can help navigate the changeover.

Vice President of System Planning Aubrey Johnson said the "vast majority" of projects to address age and condition of existing equipment — which represent the largest spending share of MTEP 22 — are not conducive to alternative project proposals. He said lower-voltage lines simply need replacement in many cases.

Johnson said MISO believes it has a comprehensive and transparent planning process and that he didn't notice members taking exception to any projects in particular. He said MISO's separate long-range transmission planning process resolves many of the Environmental sector's concerns over MTEP being too short-sighted.

Some members have asked if the vote tally was concerning to MISO and whether the RTO needs to reassess this year's transmission spending package.

"I think the vote indicates that many feel that there's still a need to improve the MTEP report," Clean Grid Alliance's Natalie McIntire told board members. She said MISO should remove MTEP 22's references to natural gas generation being able to provide a reliable backstop to renewable generation's output and that the RTO needs to keep with its practice of being resource agnostic.

| © RTO Insider LLC

But Prairie Power's Karl Kohlrus said MISO hasn't adequately factored in its planning how removal of all Illinois' fossil generation by 2045 under the state's Climate and Equitable Jobs Act will affect system reliability.

"MISO is heading for a major train wreck," he warned.

Kohlrus has previously said during planning meetings that he was concerned that the RTO isn't reflecting enough future baseload retirements in its 20-year models used for transmission planning.

Johnson said stakeholders' comments are expected, given the accelerating resource shift.

MISO Director Nancy Lange said MISO's review of age and condition projects should consider "factors that all these regions are grappling with."

Johnson said transmission projects related to age and condition and load growth provide the foundation for long-range transmission planning to accommodate the resource transition. He said there's "a lot of connective tissue" between MTEP and long-range transmission planning.

"We're in a state of transition right now. It's taking a tremendous amount of effort from all parties to do this foundational work," he said.

"It's not surprising that we're having a lot of differences of opinion," MISO Director Phyllis Currie said, adding that the board and MISO take stakeholders' concerns seriously.

During an Advisory Committee teleconference Oct. 26, the Union of Concerned Scientists' Sam Gomberg asked if MISO was weighing whether to open an inquiry into MTEP 22's scant support to avoid conflict with approving the transmission package later this year.

"It's certainly something that raised my eyebrows, personally," Planning Advisory Committee Chair Cynthia Crane said.

WEC Energy Group's Chris Plante also said he thought the voting results were "concerning."

MISO Senior Director of Transmission Planning Laura Rauch said the comments explaining why some MISO sectors withheld support of the plan are "helpful."

Rauch said the vote "did not mean stakeholders weren't active and engaged" in this year's planning process. She said MISO looks for ways to continually improve the MTEP process. ■

MISO News

Entergy Learning from Florida to Improve Resilience

CenterPoint Earnings down YoY, but Better than Expected

By Tom Kleckner

Entergy on Wednesday said it is engaging with stakeholders as it prepares regulatory filings related to its proposed $15 billion, 10-year accelerated resilience plan to upgrade its system against future storm damage.

Entergy CEO Drew Marsh | *Entergy*

"We've invested in new infrastructure built to higher standards that will improve the system's resilience," CEO Drew Marsh told analysts during Entergy's third-quarter conference call. "We expect our proposed investments to significantly reduce physical and financial storm risk."

Marsh said the *plan* is "heavily informed" by Florida's recent experience with Hurricane Ian.

"We did our homework," the new CEO said. "Knowing that their hardened assets performed well in Hurricane Ian, along with the strong performance of our own hardened infrastructure over the past couple of years, gives us confidence that we can substantially reduce our exposure to storms and provide meaningful benefits to customers."

The utility has already made its first filing, with New Orleans, where it came under heavy criticism last year after Ida took out all eight transmission lines servicing the city. (See *Entergy Touts Restoration; NOLA Leaders Question Lack of Blackstart Service*.)

The New Orleans City Council has already approved a $206 million securitization recovery for Entergy New Orleans' Hurricane Ida costs and to replenish the company's storm escrow. The company plans to file its resilience request in Louisiana by the end of the year and in Texas next year.

Entergy reported quarterly earnings of $561 million ($2.74/share), up from the same period a year ago when it delivered earnings of $531 million ($2.63). Marsh said the strong quarter allowed Entergy to cut 10 cents off its year-end adjusted earnings guidance, now $6.25 to $6.45.

The utility's adjusted earnings of $2.84/share beat the Zacks Consensus Estimate of $2.67/share.

The earnings call was Marsh's first as CEO. He replaced Leo Denault, who stepped down on Nov. 1 and continues to chair the company's board. (See *Entergy CEO Denault Stepping Down in 2023*.)

CenterPoint Exceeds Expectations

CenterPoint Energy on Nov. 1 reported earnings of $189 million ($0.30/diluted share), a tick down from last year's third quarter of $190 million ($0.32/diluted share).

The Houston-based company updated its capital expenditure plan by $2.3 billion to nearly $43 billion. CEO David Lesar said the incremental capital will be dedicated to further distribution system resilience, reliability and grid modernization, and transmission upgrades in its Houston Electric area.

CenterPoint's adjusted earnings of 32 cents/share beat the Zacks Consensus Estimate of 31 cents, the 10th straight quarter Lesar's management team has met or exceeded Wall Street's expectations.

The company's share price finished at $28.11 on Wednesday, down 48 cents from its pre-announcement close. ■

Entergy plans to spend $15 billion over 10 years to improve its grid's resilience. | *Entergy*

MISO News

MISO Proposes Leaner 2023 Budget

Base Operating Costs Up; Other Expenses Down

By Amanda Durish Cook

MISO plans to spend $364.2 million throughout 2023, a 3.2% decrease from this year's budget.

The RTO plans to spend $310.5 million in base operating expenses, $18.2 million in other operating expenses and $35.5 million in project investments, which include its ongoing effort to replace its market platform.

The MISO Board of Directors' Audit and Finance Committee gave the preliminary budget unanimous support during a teleconference Nov. 1. The full board will hold a vote on the proposed budget in early December.

The grid operator remains concerned about employee salary hikes it might have to institute. It intends to spend about $28 million in base operating expenses, a 10% increase over 2022 and said the increase is necessary to onboard more staff to safeguard reliability

"A lot of these are intellectual efforts," CFO Melissa Brown explained to board members. She said "wage pressures to attract the talent we need" remain a risk to staying within next year's budget confines, noting "ripples" from upping salaries caused the most disruption to the 2022 budget. (See "High employee turnover concerns leadership," *MISO Board Week Briefs: Sept. 12-15, 2022*.)

However, MISO said it can more than offset the additional spending with a 68% ($38.5 million) decrease in its other expenses category because of higher rates earning more interest income. Other operating expenses includes capital labor, capital interest and other income losses.

MISO control room | *MISO*

Brown said overall, the grid operator expects to collect a 44-cent/MWh tariff rate from its members in 2023, lower than its 45-cent/MWh rate in 2022.

Alliant Energy's Mitch Myhre, who chairs the stakeholder-led Finance Subcommittee, said members are concerned over real-world pressures that could impact the 2023 budget. He said MISO could find itself spending $8 million more than expected if it continues to have difficulties maintaining its talent pool and called for staff to "actively manage" the situation.

"It is important that MISO is a judicious and conscientious steward of funds received from its members and remain vigilant against material budget increases or overages," Myhre said. ■

MISO News

FERC Rejects Iowa Coalition's Complaint over ITC Structure

By Amanda Durish Cook

FERC said Wednesday that ITC Midwest can keep the capital structure it has had in place since 2007, blocking an Alliant Energy-led complaint in the process (*EL22-56*).

Alliant's coalition of Iowa utilities, industrial customers and consumer advocates in May challenged ITC's capital structure as excessive and too skewed toward equity. They asked the commission to reduce ITC's equity ratio to 53% and establish hearing and settlement procedures to grant refunds to transmission customers. (See *Alliant Energy Leads Challenge of ITC Midwest Capital Structure*.)

ITC Midwest, an independent transmission company, uses a capital structure reflecting 60% equity and 40% debt in its formula rate to calculate its overall rate of return.

FERC said the coalition did not prove that the utility's existing capital structure is unjust and unreasonable. It ruled that ITC's target capital structure is comparable with those used by other investor-owned MISO transmission owners and is not unusually high.

The commission also pointed to its policy of using the actual capital structure "of the entity that provides the financing, whether that entity is the utility or its parent company."

Iowa customers argued that FERC's approval of ITC's 60% target equity ratio 15 years ago was "based on the expectation that ITC Midwest would have its own credit rating separate from its parent company," ITC Holdings. They argued that both the utility and MISO have undergone seismic changes since the capital structure was approved, with ITC Midwest's rate base increasing 550% since 2008 and ITC Holdings being acquired by Fortis, Inc.

Both the Iowa Utilities Board and the Minnesota Department of Commerce intervened at FERC in support of the complaint.

However, the commission said the Iowa customers didn't establish that either ITC Holdings or Fortis guarantees ITC Midwest's debt or that they would assume its debt obligations if the utility defaulted. FERC also said that contrary to allegations, ITC Midwest has a different bond rating from ITC Holdings and Fortis.

"Although ITC Midwest does not have its own management-level employees and relies on ITC Holdings' management, this does not demonstrate that ITC Holdings guarantees ITC Midwest's long-term debt," FERC said. ■

| *ITC Holdings Corp.*

MISO News

MISO Membership Reelects Incumbent Directors for 2023

By Amanda Durish Cook

MISO's membership voted to retain three incumbent directors, ensuring the board of directors' lineup will remain the same next year.

The grid operator said Thursday that current directors H.B. "Trip" Doggett, Barbara Krumsiek and Todd Raba will take their seats at MISO's U-shaped board table for their final three-year terms.

The trio joined the board on Jan. 1, 2017. Board members are limited to serving three, three-year terms. Raba currently chairs the board.

"Chair Raba and Directors Doggett and Krumsiek have a thorough understanding of the challenges facing our industry, and I look forward to continuing our work together to meet those challenges," MISO CEO John Bear said in a statement. "Their expertise and institutional knowledge will serve us well as we accelerate our reliability imperative efforts."

MISO's board consists of nine independent directors and the CEO.

Although the Nominating Committee interviewed other candidates this year, it ultimately decided to advance for consideration only the incumbent directors up for reelection. (See "Board Will Remain Same in 2023," *MISO Board Week Briefs: Sept. 12-15, 2022*.)

MISO board members in December 2021 | © *RTO Insider LLC*

MISO membership cast votes this year from Sept. 22 to Oct. 28. The board elections are conducted electronically and require a minimum 25% participation rate among its nearly 140 voting-eligible members to achieve quorum. Members can vote for, against or abstain from selecting any of the candidates. Candidates must earn a majority of supportive quorum votes to be installed. ■

NYISO News

Champlain Hudson Power Express Closes on Financing

Construction of $6B Transmission Line to Begin Soon

Champlain Hudson Power Express last week said it has closed on the financing needed to build its roughly $6 billion underground transmission line linking Quebec and New York City.

All major permits for the 340-mile U.S. portion of the 1,250-MW transmission line are in place, and construction will begin this fall in New York, CHPE said. Government permits for the 36-mile Canadian portion of the project are anticipated in summer 2023, and completion is projected in spring 2026.

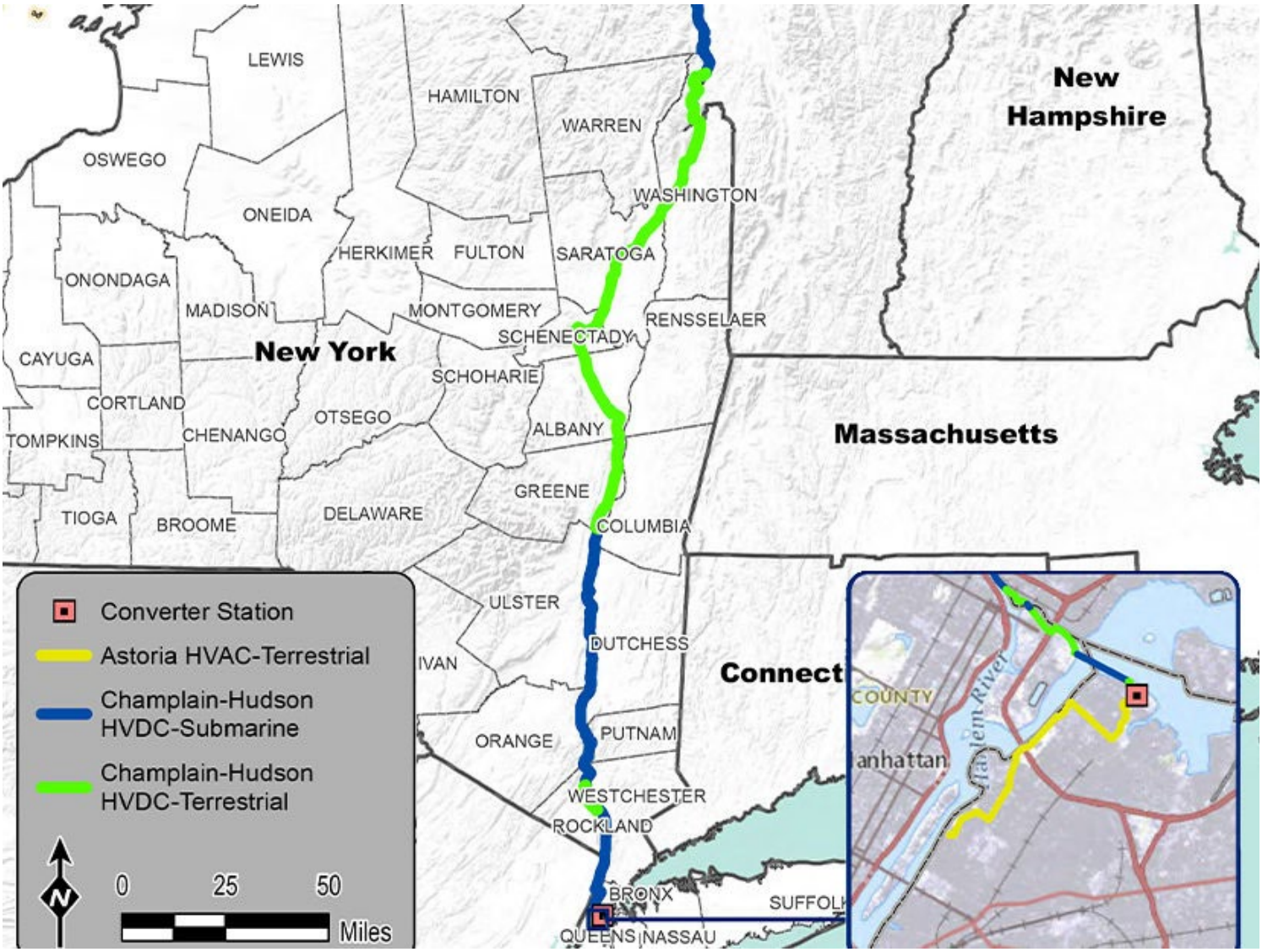
Along with construction costs, the project price tag includes tens of millions of dollars for community benefit projects over the next several decades.

"The project financing announced today is an important step toward starting construction and beginning to realize the tremendous economic and environmental benefits this project will provide to residents, organizations and municipalities throughout the state," Donald Jessome, CEO of TDI-USA Holdings, CHPE's parent, said in a news release. "We look forward to watching our community partners move forward with vital projects that will improve the communities they live and work in, and to soon begin delivering clean, renewable energy to New York City."

CHPE has been in the works for more than a decade: It was first proposed in 2010, and it received approval from the New York Public Service Commission in 2013.

It is an important part of the state's decarbonization strategy, as it will bring more than 1 GW of zero-emission hydroelectric power to a region that now relies heavily on fossil-generated electricity. ■

— John Cropley



The Champlain Hudson Power Express underground HVDC line will carry up to 1.25 GW of power from Quebec to New York City on this route. | *Transmission Developers Inc.*

NYISO News

NYISO Identifies 35 Projects for Narrowed SRIS Scope

By John Norris

| © RTO Insider LLC

NYISO has proposed narrowing the system reliability impact study (SRIS) scopes for 35 generation projects in the queue in order to expedite the interconnection process.

The Transmission Planning Advisory Subcommittee on Nov. 1 unanimously recommended that the Operating Committee approve the proposal at its next meeting, currently scheduled for Nov. 17.

The SRIS evaluates the impact of a project on the existing electric system, including future firm transmission projects. As a growing number of projects request interconnection in New York, the ISO has sought to find ways to move the SRIS process along in a timelier manner without jeopardizing grid or project reliability. (See "Interconnection Queue Streamlining," *NYISO Operating Committee Briefs: Oct. 13, 2022*.)

Thinh Nguyen, senior manager of interconnection projects, said that certain evaluations in the projects' studies were removed because they were identified as being "redundant" or could be "conducted at a later stage." There are also "informal ways" for developers to provide the additional information related to the study, he said.

Not every SRIS scope was narrowed in the same way. Mark Reeder, representing the Alliance for Clean Energy New York, asked how the ISO determined which evaluations to remove from each of the scopes and why they were not removed from every identified project.

Nguyen responded that they went on a "case-by-case" basis because not every scope had a particular evaluation; some projects' evaluations were already ongoing; and other scopes already completed certain evaluations.

Howard Fromer, who represents the Bayonne Energy Center, asked whether removing the evaluations from the SRIS scopes required modifications or updates to any ISO procedures, manuals and tariffs, or if this was simply within NYISO's discretion.

Nguyen responded that no modifications or other changes were needed, with the only requirement being OC approval, as well as transmission owner sign off, as the ISO lacks the "unilateral authority" to make these changes outright. ■

PJM News

Crane to Retire, Butler to be New CEO of Exelon

Utility Reports 'Solid' Q3 Earnings

By John Cropley

Exelon announced a leadership transition on Wednesday and reported "solid" third-quarter financials on Thursday.

Current President and COO Calvin Butler Jr. will succeed Chris Crane when he steps down Dec. 30 as CEO and a member of the Chicago-based utility's board.

Crane, who has been Exelon's CEO since 2012, said he had to accelerate his retirement plans because of significant health issues.

Butler has held a series of leadership roles since joining the company in 2008. He was named executive vice president and COO in February 2022 and was promoted to president just two weeks ago.

Crane presided over his final quarterly earnings call Thursday, updating industry analysts on the company's outlook and performance, which he described as "solid."

For the third quarter of 2022, *the company reported* GAAP net income of 68 cents/diluted share and adjusted (non-GAAP) operating earnings of 75 cents, up from 47 cents and 53 cents, respectively, in the same quarter in 2021. For the first nine months of this year, Exelon reported $1.65/share, up from $1.33 in the same period of last year.

The company narrowed its guidance for the full 12 months of 2022 to $2.21 to $2.29 in adjusted (non-GAAP) operating earnings per share.

Like the rest of the Nasdaq Composite, Exelon's stock is near a 52-week low. The share price was down 2.84% in heavier-than-average trading on Thursday as the index declined 1.73%.

During Thursday's conference call, Crane addressed the monumental transition to clean energy underway in the electric utility industry. Exelon, he said, is well positioned to lead and benefit from the shift.

"Exelon offers an unparalleled exposure to that opportunity," Crane said. "We serve more electric and gas customers than any other utility in the country in some of the largest cities of the country. We have earned the trust of our customers and our commissions by consistently reliably providing top-notch operation performance.

Chris Crane (left) and Calvin Butler | *Exelon*

"And we live our values with steady commitments to our path-to-clean goal as well as through environmental advocacy and support for our communities in a strong governance model. As a result, there is a tremendous demand and support for investments we expect to make in our communities, which, as I said earlier, totals $29 billion of capital from 2022 to 2025."

'Privilege and Responsibility'

Crane has spent his entire career in the energy industry, joining Commonwealth Edison in 1998, shortly before it became part of Exelon.

He was named Exelon's chief nuclear officer in 2004 and took over leadership of its fossil, hydro and renewables facilities in 2007.

Crane was named president in 2008 and CEO in 2012. Under his leadership, Exelon acquired Constellation Energy and Pepco Holdings Inc. in 2012 and 2016 to become the largest U.S. energy company by customer count.

Also on his watch, ComEd became embroiled in a multiyear bribery scandal at the Illinois Capitol, allegedly forking over $61 million in return for legislation that boosted its profits and bailed out its money-losing nuclear plants. A federal investigation ultimately led to the indictment of several former Exelon executives and a *$200 million fine for the company* in 2020.

Crane's successor has three decades of experience in the utilities industry and in regulatory, legislative and public affairs.

Early in his career, Butler worked in government affairs at Central Illinois Light Co. He later had senior leadership roles with R.R. Donnelley, a print, digital and supply chain company. He joined Exelon in 2008 and held various leadership roles at ComEd and Baltimore Gas and Electric before becoming BGE's CEO in 2014.

He holds a bachelor's degree from Bradley University, a juris doctorate from Washington University School of Law and an honorary doctorate of humane letters from Morgan State University.

"Leading Exelon is a privilege and responsibility that I take very seriously," Butler said in a news release. "Chris is a tremendous leader, mentor and friend. As our world has been undergoing significant change, so too has the energy industry, and Chris has been at the forefront of that evolution. At Exelon, we are uniquely positioned to lead the nation and our industry to a clean energy future that is safe, reliable, affordable and equitable for all. I appreciate the Board's confidence in me and will do everything I can to serve our customers and communities, keep our employees safe and move the energy industry forward." ■

PJM News

PJM, NJ Look Beyond SAA Transmission Upgrade Process

'Free Rider' Concern Cited

By Hugh R. Morley

ATLANTIC CITY, N.J. — PJM and the New Jersey Board of Public Utilities (BPU) are considering how to incorporate other states in future public policy transmission upgrades, an acknowledgement that the RTO's State Agreement Approach could benefit "free riders," officials told a conference Oct. 28.

The BPU voted Oct. 26 to award $1.07 billion in upgrades to deliver offshore wind generation to the PJM grid in the first application of the RTO's State Agreement Approach. The SAA allows states to sponsor transmission to support their public policy needs while requiring them to pay 100% of the costs. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

The BPU's award will fund onshore transmission upgrades needed to integrate 6,400 MW of offshore wind, but it does not include any offshore transmission and further upgrades will be needed to meet the state's new offshore wind goal of 11 GW. As a result, the BPU directed its staff to begin a second round of coordinated transmission planning to meet the increased goal, potentially including a new SAA solicitation.

One question that needs to be addressed is how to allocate costs for non-New Jersey projects that want to bring energy to the system through upgrades funded by New Jersey ratepayers, Kris Ohleth, executive director of the independent *Special Initiative on Offshore Wind* told the Time For Turbines conference in Atlantic City.

Ohleth, who moderated a panel before an audience of 125, described a situation in which "New Jersey is paying for this type of upgrade to our system, and the region benefits from offshore wind" projects using it.

BPU Executive Director Bob Brabston, who appeared on the panel with Asim Haque, PJM's vice president of state and member services, said the BPU is just beginning to consider the free-rider issue raised by Ohleth.

"No one wants to pay for something that they're not getting the benefit of," Brabston said. "And we feel like there are a lot of benefits that will flow out of New Jersey because of this. But it's really conceptual at this point. So, in terms of what that would really look like in terms of how complex cost allocation can be, and the different perspectives among our fellow member states, it's really early to say how that might work out."

Brabston echoed BPU General Counsel Abe Silverman, who said in September that state officials hope to engage in "horse trading" with other PJM states over the cost allocation of transmission needed to meet their climate goals. (See *NJ Foresees 'Horse Trading' with Other PJM States over Tx Costs*.)

PJM's Haque said the cost allocation issue is part of a "robust discussion" underway in the industry about how it can be more proactive in addressing state transmission build-out needs. "Electrons don't know state borders," he said.

"We're finding ourselves in a space where there are multiple states that are actually sort of sharing similar policy initiatives, whether it's renewable portfolio standards or offshore wind initiatives," he said. "Generally speaking, PJM is supportive of the sort of long-term, long-range transmission planning. And we're supportive of thinking about how the states can get more involved in determining what cost allocation should look like."

That's complicated because states are at "different sort of points on the spectrum," he said.

"You've got states in the PJM footprint that say that we, we don't want to pay a dime for something that didn't arise out of our state legislature, or an executive order or whatever," he said. "And you have some states in the middle that said, 'Well, let's look at all the different benefits that would arise from this project. And if some benefits would eventually find a way to our consumers, we can conceivably pay for it.' And you have states that say, 'You know, there are so many states that with similar policy objectives, it makes sense for a lot of our states to go at it together and share costs.'"

John Dempsey is CEO of Blue Point Wind, a joint venture between EDP Renewables and Engie, which won the auction for an offshore wind development lease in the New York Bight in February. | © *RTO Insider LLC*

Cost Reductions Through SAA

New Jersey's process was the first time that any state has used the FERC-authorized SAA process, and conference speakers said the results demonstrate the benefits of the approach.

The BPU approved $504 million for work in and around the Larrabee substation in Central Jersey to FirstEnergy's Jersey Central Power and Light and Mid-Atlantic Offshore Development (MAOD), a joint venture of Shell New

PJM News

Energies US and EDF Renewables North America. The state also will spend $575 million for other upgrades to accommodate OSW generation.

BPU officials say that the $1.07 billion price tag is about $900 million lower than the upgrades would have been without the coordination and competitive bidding overseen by PJM under the SAA. PJM's solicitation generated 80 proposals from 13 developers.

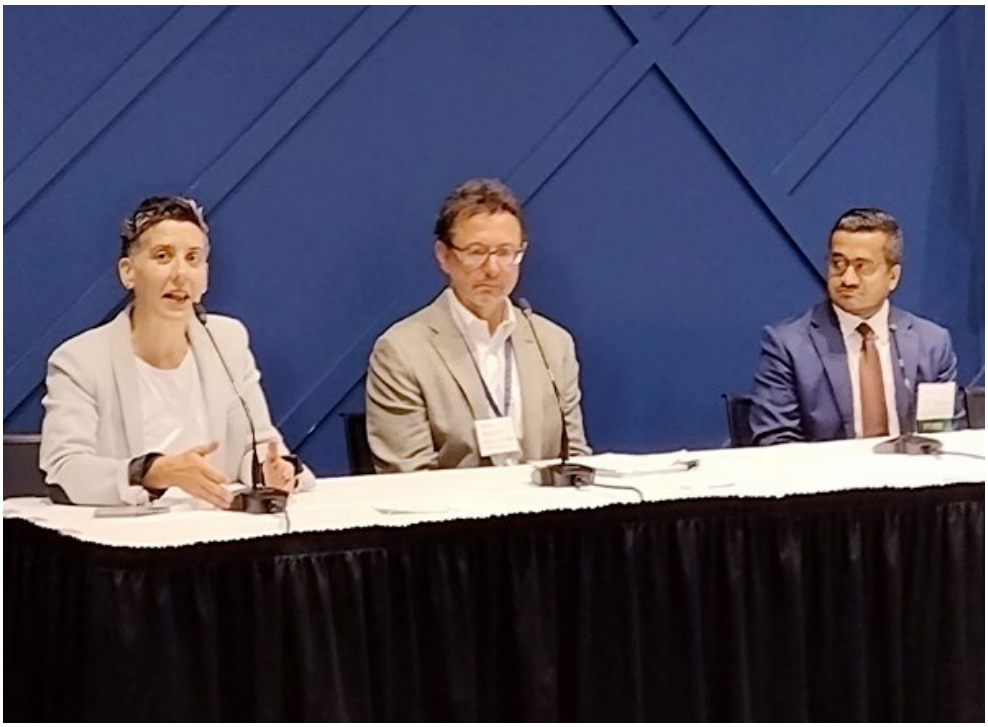
Without the coordinated process and competition the transmission upgrades needed would evolve through "many developers, many projects proceeding on their own timeline with their own decision making, their own priorities," Brabston said. That could mean some benefits, such as "a lot of innovation and competition, but also a lot of duplication, no economies of scale, and a lot of impacts on communities and on the environment," he said.

Although the BPU sought proposals for connections on and offshore, the BPU funded only onshore projects, leaving the offshore work still to be allocated. The board expects the winner of the third solicitation, which is due to take place early in 2023, to include plans for the offshore connections that will tie future projects to the upgraded transmission facilities just approved by the board.

"One of the aspects of the project that we awarded is the expectation that all of the cabling access that's required for all of the offshore generation that we expect to award in future solicitations will come through the same landing point," Brabston said. "And that's a way that future developers will know with certainty where they need to come onshore, and that that particular asset will be there already constructed."

Haque acknowledged that the SAA prompted PJM to change its own strategy.

"We weren't always in the space of trying to figure out how to help states," he said. "PJM was not always the most friendly to state policy endeavors. And so for us to have gone from a space where we had [BPU] President [Joseph] Fiordaliso say, 'We may not be seeing eye to eye with PJM in the future' to where we are now: We jointly figured out a path to build



From left: Kris Ohleth, executive director at the Special Initiative on Offshore Wind; BPU Executive Director Bob Brabston; and Asim Haque, PJM vice president of state and member services | © *RTO Insider LLC*

transmission to bring offshore wind to New Jersey consumers. … I think it's really wonderful."

Helping to De-risk

John Dempsey, CEO of Blue Point Wind, a joint venture between EDP Renewables and Engie, which won the auction for an offshore wind development lease in the New York Bight in February, said the initiative would also help developers and the industry as a whole. Speaking on a panel that focused on OSW project developments off the New Jersey coast, he said the state's SAA was a "tremendous, tremendous effort."

The initiative "really goes a long way at helping de-risk projects, which lowers costs," he said. "The efforts made by the state earlier in the week, I think really go a long way at making New Jersey a really good place for offshore wind developers to land, so we were really pleased to see that."

Dempsey, in an email after the conference, said that as states increase their offshore wind capacity targets the industry will need more "proactive transmission development" like the BPU's initiative to make projects happen.

Blue Point Wind, also known as Ocean Winds East, paid $765 million for its New York Bight lease, giving the developer rights to an ocean parcel 53 miles off the New Jersey Coast that is expected to generate 1,700 MW of electricity. The project will sell its power to either New York or New Jersey and is evaluating "multiple interconnection scenarios" at each location, Dempsey said.

"The BPU award offers clarity to the industry on the optimal cable landfall location and the point of interconnection for the next round of projects, and it will ensure that there is sufficient transmission capacity on the system to accommodate offshore wind," he said. "For developers like Bluepoint Wind, this clarity will reduce uncertainties in their projects and allow them to offer more competitive proposals to New Jersey in its upcoming solicitations." ■

Mid-Atlantic news from our other channels

Dominion, Va. Stakeholders File Settlement over Performance Req for OSW Project

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PJM News

PJM General Session Focuses on Clean Energy Transition

By Devin Leith-Yessian

CAMBRIDGE, Md. — PJM's biannual General Session last week focused on how to ensure both reliability and equity during the transition to a clean energy-based generation mix.

NERC CEO Jim Robb moderated the first panel, introducing it by saying that reliability, environmental impact and affordability will all be challenged during the transition to relying on renewable power. Over the next 10 years, NERC expects to see increased risk from extreme weather and tight supply margins as the decommissioning of fossil fuel generation runs up against increasing demand from electrification.

Jeff Craigo of ReliabilityFirst said the regional entity has had success with an initiative to survey generation facilities' winterization efforts, which has allowed it to share those experiences across the industry.

Peter Brandien, ISO-NE vice president of system operations and market administration, said the RTO is focusing less on specific percentages of capacity, and more on understanding what kinds of resources are available and their characteristics.

The RTO's response to the transition has centered on four pillars, Brandien said: handling the influx of clean energy resources; a supply of balancing resources to preserve reliability; maintaining resource adequacy to meet demand when solar and wind power aren't available; and having adequate transmission to import more renewable energy and to ensure renewable resources aren't constrained when they're needed.

Resource adequacy in particular has been challenging within New England. Unlike other areas of the country where the problem is getting through the peak load day and resetting for the next, New England has limited storage (LNG, oil, hydro or long-duration batteries) and can run short of supply, particularly during extended cold weather. Siting has also proven to be another challenge, and Brandien noted the struggle of the New England Clean Energy Connect transmission line.

Confidence in the reliability of the grid is crucial to industries looking to make investments, which Brian George, lead of Google's energy regulatory and policy engagement team, said is reflected in the company's heavy investments in PJM.

PJM President and CEO Manu Asthana introduced the speakers on two panels addressing the clean energy transition during the RTO's General Session on Oct. 25. | © *RTO Insider LLC*

"Our users expect and demand reliability all the time and everywhere, so that's at home, that's in the office. … Whenever they pull up the browser, they expect us to be there," he said.

To meet the company's climate goals, he said Google has shifted its focus to the procurement of energy for when and where it's needed, rather than the installation of additional renewable resources. He said the open markets, which have created affordable and reliable power in PJM, will play a key part in addressing that focus while meeting its growing demand.

Nancy Bagot, senior vice president of the Electric Power Supply Association, said the transition is the time to double down on competition to encourage more innovation, while shielding customers from the risks of finding the right balance of resources. There will have to be an acknowledgement that markets are being asked to break new ground, she said, and the conversations on how to do so will need to remain grounded in reality and based on the voices of reliability experts.

That will involve reimagining the capacity market in what it signals and procures for different regions of the country, including a look at what the mix of capacity available is, rather than the raw amount in the market, Bagot said.

Bobby Jeffers, program manager at the National Renewable Energy Laboratory, spoke about the lab's efforts to improve the models, tools and calculators available for gauging reliability. Incorporating a better understanding of how supply chains function and geopolitics is necessary for creating modeling for a system that works.

NREL is also upgrading its Interruption Cost Estimate calculator to reflect the societal costs of extended outages, Jeffers said. The economic impacts currently incorporated into the tool fail to reflect the toll outages can take on customers.

Responding to the question of whether FERC should play an activist role or take a more passive, judicial approach to the transition, the panelists largely agreed that stability and deference to RTOs were preferable.

Brandien said that grid operators know their regions best and they can carry out their responsibilities more effectively without NOPRs and filings confusing the waters. George said it's important that if FERC has a preference on a policy, it should make it known and take the lead, rather than leave RTOs in the dark.

Equity and Environmental Justice

The second panel focused on ensuring that the costs of the transition don't fall disproportionately on disadvantaged communities and examining how to reconcile the need to expand energy infrastructure and the burden it often

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places upon the communities that host it.

One of the largest challenges in ensuring the equity of wholesale energy markets remains the lack of public knowledge about their functioning, said Damali Rhett Harding, managing principal for the Regulatory Assistance Project.

"How do we incorporate equity into a marketplace that probably 99% of Americans don't realize exists?" she questioned.

To provide equity in energy, she said companies need to examine the procedures that prevent people from participating in the siting process.

Beyond just educating the neighbors of a proposed project, former U.S. Rep. Joseph P. Kennedy III (D-Mass.), now managing director of Citizens Energy, said developers and utilities should explore ways to ensure that the expansions directly benefit those communities. He pointed to a project in which his nonprofit partnered with a utility to invest in a large transmission project in California's Imperial Valley, and then used the profits it earned to construct a 30-MW community solar installation in the city of Calipatria. In addition to improving reliability, the solar project provides about $500 in annual savings every year over 20 years to 12,000 low-income households in a region where temperatures can exceed 110 degrees Fahrenheit, he said.

Such arrangements can prove worthwhile even to for-profit companies by alleviating residents' concerns that large transmission projects could lower property values or disrupt their neighborhoods with no visible benefit to them, Kennedy said. The costs of the delays or resiting of projects can often well exceed the expense of profit sharing with those communities, he argued.

Delaware Public Service Commissioner Harold Gray, who moderated the panel, said incorporating more voices can help companies find more forms of value than immediate profit alone. In his work on the commission, he has had success showing utilities that by keeping their customer's interests in mind, they can discover new customers and potentially expand profits.

Former FERC Commissioner Colette Honorable, now a partner at Reed Smith leading the firm's energy regulatory group, noted that getting all parties on board with a project in the early phases can reduce the likelihood of prolonged, and expensive, delays at FERC and the federal courts.

"You're in trouble if you have a matter pending and the first time you hear them is when they object," she said.

Likewise, she said incorporating equity into the work done by RTOs can be accomplished by examining what voices are missing at the table and including those stakeholders who aren't represented. On public education, she said FERC's new Office of Public Participation has been making strides in ensuring that individuals at all levels are empowered to make their concerns heard. ■

PJM News

Monitor Finds PJM's 2023/24 Base Residual Auction Competitive

By Devin Leith-Yessian

The 2023/24 Base Residual Auction held by PJM in June yielded competitive results, the RTO's Independent Market Monitor announced in a *report* released last month, owing largely to the implementation of a 2021 FERC order reworking the derivation of the market seller offer cap (MSOC).

Monitoring Analytics' report, released Oct. 28, said the shift from basing the MSOC off the net cost of new entry (CONE) to using the avoidable-cost rate (ACR), as ordered by FERC, addressed concerns about the ability to exercise market power and uncompetitive outcomes leading to customers being overcharged. (See *PJM Capacity Prices Crater* and *FERC Backs PJM IMM on Market Power Claim*.)

"The net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs," the Monitor said. "The logical circularity of the argument, as well as the fact that key assumptions are incorrect, means that the [Capacity Performance] market seller offer cap was not based on economics or logic or math."

Despite believing the auction succeeded in securing competitive results, the Monitor wrote that the Reliability Pricing Model still has many components of a "significantly flawed market design." These include the shape of the VRR curve; the participation of demand response resource in the capacity market; capacity imports; and the overstatement of intermittent capacity offers.

In addition to taking issue with intermittent resources offering capacity at a higher rate than permitted by their capacity interconnection rights, the Monitor said exempting those resources from the must-offer rule raises market power issues stemming from the ability to withhold supply.

Adam Keech, PJM | © *RTO Insider LLC*

"The failure to apply the must-offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases and the level of demand-side resources remains high. The failure to apply the must-offer requirement consistently could also create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk," the report says.

The report called for a consistent definition for capacity that includes being a physical resource at the time of the auction for all resource types. That requirement is not currently being applied to DR, nor to energy efficiency, both of which the Monitor said should be shifted to the demand side of the market. It also wrote that EE is accounted for in PJM's load forecasting and the payments such resources receive don't provide added incentive for participant behavior.

The use of a sloping VRR curve procures excess capacity and masks the flaws of "permitting the participation of inferior demand-side resources in the capacity market" by avoiding the need to rely on those resources, the Monitor argued. It said that the use of a vertical demand curve "equal to expected peak load plus a required reserve margin" would reduce capacity payments by nearly $1 billion. The report noted that the IMM's recommendation was to rotate the curve halfway toward vertical for the current quadrennial review, while PJM opted for a curve rotated a quarter of the way.

"Use of the VRR curve increased the purchase of capacity [by] 10.1% and increased the total load payments for capacity by $983 million, or an increase of 81.1% compared to a vertical demand curve," the report says.

During an Oct. 18 panel at the Organization of PJM States Inc.'s Annual Meeting, PJM Vice President of Market Design Adam Keech said that a vertical curve would temporarily lead to lower capacity prices, but in the long term, it would replicate the very volatility that led to the creation of the capacity market in 2005. That volatility could lead to more generation owners deciding to retire their units, ultimately driving prices higher.

Though it hailed the shift to basing the MSOC on the ACR going forward, the Monitor that the ACR definition should be reworked to be based on the cost of producing additional capacity. Currently it's defined in the tariff as the costs of operating a generator for the given delivery year.

Joe Bowring (right), president of Monitoring Analytics, speaks during the Organization of PJM States Inc.'s annual Market Monitoring Advisory Committee meeting on Oct. 18 while David Mills of PJM listens. | © *RTO Insider LLC*

"Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity, whether a new resource or an existing resource," the report says.

The report found that 139,399.5 MW of generation and DR cleared in the BRA, with a reserve margin of 21.6% and a net excess of 7,835.3 MW over the reliability requirement. The net excess increased 175.1 MW up from the 2022/23 BRA, which had an excess of 7,660.2 MW.

The report said that a vertical demand curve would have reduced revenues by 44.8%, bringing the total from auction clearing prices, quantities and uplift from $2,196,444,791 down to $1,212,977,260.

The accuracy of the peak load forecast also had a "significant impact on the auction results," with the forecast for the third incremental auction being on average 3.1% lower than the forecast for the corresponding BRA. If the forecasted results had been 3.1% lower, total auction revenues would have been $1,729,724,427, a decrease of $466,720,364, or 21.2%, compared to the actual results.

The report found that the 15.5% decrease in the Commonwealth Edison capacity emergency transfer limit (CETL), amounting to 1,058 MW, did not have an impact on the auction results. ■

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PJM Operating Committee Briefs

Stakeholders Approve Winter Weekly Reserve Target

VALLEY FORGE, Pa. — The PJM Operating Committee last week endorsed the *winter weekly reserve target* (WWRT) values, used to coordinate planned outages scheduled during winter, as recommended in the 2022 reserve requirement study (RRS).

The RRS also recommends values for the installed reserve margin and the forecast pool requirement, both of which were approved by the Markets and Reliability Committee on Oct. 24.

The WWRT is used to cover against uncertainties associated with load and forced outages during the winter month with a large enough reserve to handle any contingencies. This year's study recommended a reserve of 21% for December, 27% for January and 23% for February.

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

"When we get to the winter period, we want to make sure that the available reserves are sufficient so that we can handle those uncertainties," PJM's Patricio Rocha Garrido said. The values are fairly similar to last year's, he said.

Maximum Emergency Status Change Advances to MRC

The committee endorsed *changes* to Manual 13 to allow coal generation owners to offer their units as maximum emergency if their fuel inventories fall below 10 days because of issues outside their control and not relating to economic decisions. The proposal is set to go before the MRC for endorsement on Nov. 16.

For a unit to be able to enter into maximum emergency under the proposal, PJM cannot have declared a hot or cold weather alert or conservative operations, and the RTO can deny the use for any reason. A unit granted maximum emergency can remain in that state until they have 21 days of fuel inventory or until either of the previous conditions are met.

Independent Market Monitor Joe Bowring said the proposal could effectively put PJM in the position of managing the fuel supply risk on behalf of companies.

Synchronized Reserve Dispatch

The committee approved a revised *problem statement* and *issue charge* by acclamation to examine synchronized reserve event actions.

The issue charge argues that during an all-call to deploy synchronized reserves, the "market tools for dispatching resources based on economic order are not consistently utilized." Additional lack of clarity around the process for approving real-time security-constrained economic dispatch around a synchronized reserve event presents challenges that the work stemming from the issue charge would attempt to resolve.

The revisions made to the issue charge include education on FERC responses to filings on synchronized reserve deployment and evaluating pricing throughout the deployment events.

Monitor Presents CIP Cost Recovery Proposal

Bowring presented a slate of proposed *revisions* to PJM's issue charge on cost recovery for facilities identified as critical infrastructure, which he said would address the issue charge moving too far into the direction of proposing solutions.

The modified issue charge was initially listed under the OC's first reads, but it was moved to the informational items because no member sponsored the item. Motions to do so will be considered at the committee's next meeting.

Bowring also suggested in the revisions that it should be considered whether non-market approaches under the expected deliverables should be used, even though he believes they shouldn't.

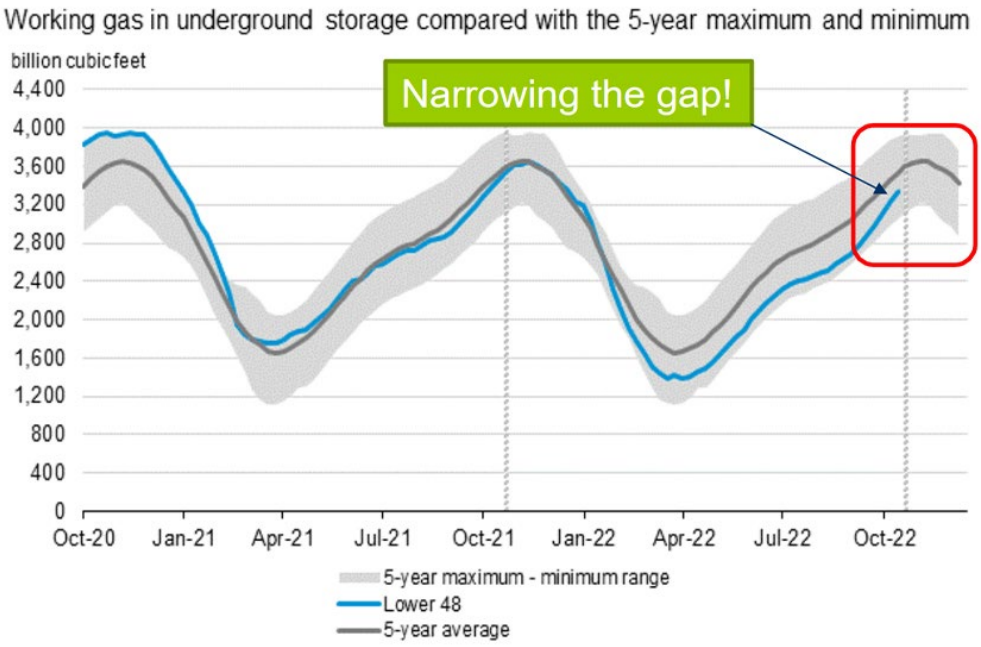
PJM Presents Winter Capacity and Load Projections

PJM's Todd Bickel *presented* the Operations Assessment Task Force study of the capacity projections for the upcoming winter season, which found that the RTO is expected to meet the 30-minute reserve requirement of 3 GW, while having an additional 14 GW on hand.

No reliability issues were identified for the base case and N-1 analysis, though re-dispatching and switching is expected to be required in some areas to control local thermal or voltage violations.

"For this winter we have sufficient margins and no reliability concerns," Bickel said.

There is expected to be 168.1 GW of capacity available this winter, which is offset by 16,510 MW of discrete generator outages. There is also expected to be 4,200 MW lost in net interchange, and 6,100 MW which could be unavailable should there be no wind and solar



Natural gas inventories remain below their 5-year average, but according to the latest Energy Information Administration reports, shown in a PJM presentation, the reserves are on an upward trend. | *PJM*

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available. The largest gas/electric contingency is expected to amount to 6,200 MW in capacity that could be unavailable.

The Load Analysis Subcommittee's forecasted peak load is 136.9 GW, while the 90/10 diversified load is projected at 143.8 GW.

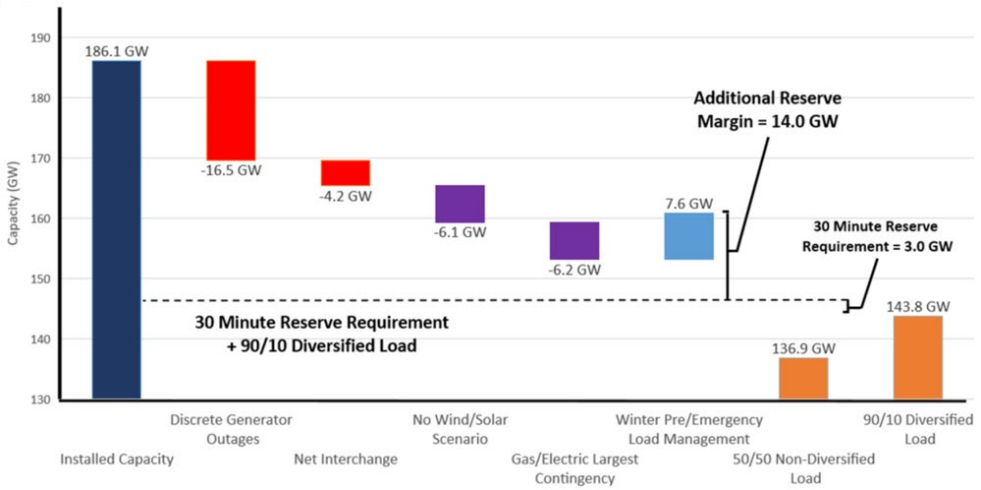
Fuel Inventories Remain a Concern

Fuel inventories are overall improving, though natural gas prices remain volatile, and the possibility of a railroad strike makes coal transportation a concern, *according to* PJM Principal Fuel Strategist Brian Fitzpatrick.

According to the latest Energy Information Administration update, the natural gas storage deficit is now 3.7% below the five-year average, compared to 5.5% in its previous update, Fitzpatrick said. PJM expects that the starting winter inventory will be around 2.5% below the five-year average.

Coal production remains high, he said, but prices remain significantly elevated over the first half of 2021. EIA remains optimistic about inventories, but there are many contingencies that could "derail" those expectations. Chief among the concerns is the possibility of a railroad strike as half of unions in the industry have yet to ratify a contract, with a Nov. 17 deadline approaching.

"It certainly could be a crippling effect," Fitzpatrick said.



The results of PJM's Operations Assessment Task Force 2022-23 Winter Study show the RTO is expected to have adequate reserves through the upcoming winter season. | *PJM*

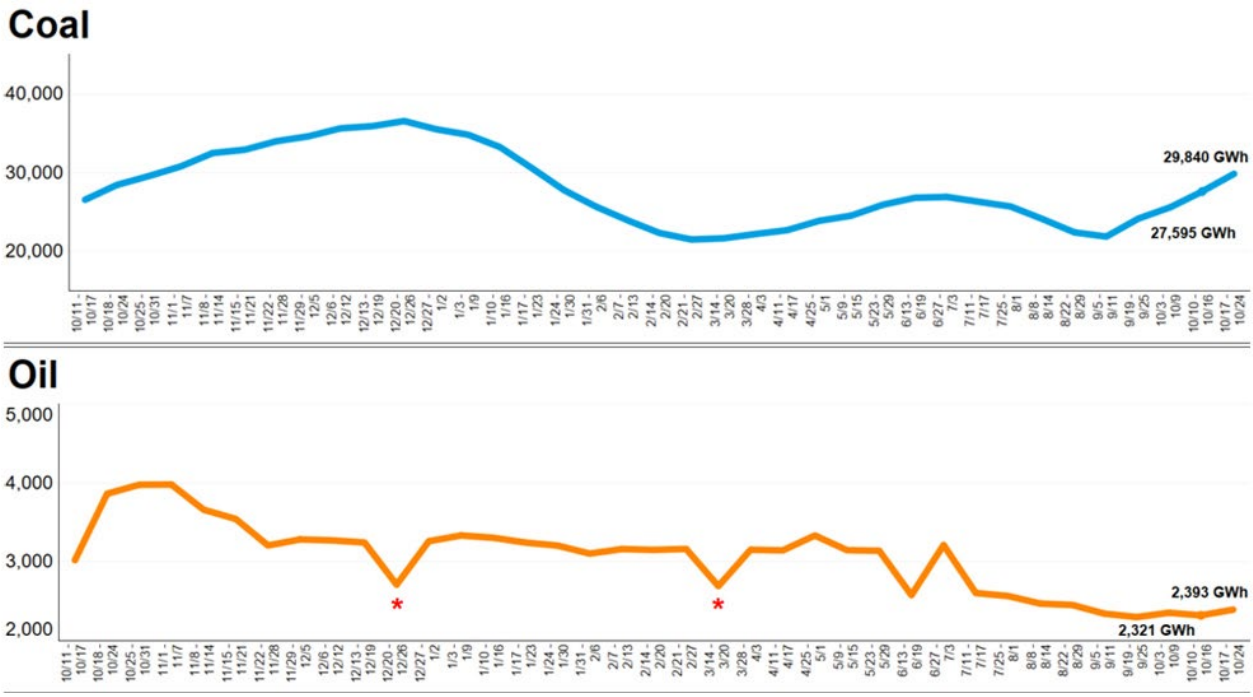
Distillate and residual fuel oil inventory also remain below their five-year averages, and price volatility remains high, with prices in the $80 to $90/barrel range. Recession fears, a strong U.S. dollar, low inventories and geopolitical tension are all driving prices, but Fitzpatrick said there are no specific concerns at this time.

PJM Cybersecurity Update

PJM Chief Information Security Officer Steve McElwee said distributed denial of service attacks remain one of the most prominent digital security issues being seen at this time as offensives continue against NATO allies. While the RTO may not be the primary target, he said there could be collateral impacts seen as the Russian invasion of Ukraine continues.

The RTO is also exploring ways to collect contacts for members' security teams so that in the event of an emergency, that information is more readily at hand. While those contacts are currently asked for in the contact management feature, it is not mandatory to provide and has primarily been used for invitations to events like conferences. ■

— Devin Leith-Yessian



Coal and oil reserves, as shown in gigawatt-hours of fuel inventory, remain below their five-year averages according to PJM's fuel supply update. | *PJM*

PJM News

PJM PC/TEAC Briefs

PJM Presents Changes to CIR for ELCC Resources Proposal

VALLEY FORGE, Pa. — The PJM Planning Committee continued fine-tuning the five remaining packages addressing the level of capacity interconnection rights (CIRs) assigned to effective load-carrying capability (ELCC) resources on Nov. 1.

PJM's Jonathan Kern presented changes to the RTO's Package I to expand eligibility for transitionary headroom studies to include all resources, rather than solely ELCC generators. The studies will investigate permitting facilities to receive a higher level of temporary/annual CIRs and include energy up to this higher level when accrediting the amount of capacity they can offer for the Base Residual Auction. The increased CIRs will be based on existing headroom in the transmission system at the time the studies are conducted. Under the proposal, they would be able to do so until all transitionary interconnection study queues have been completed, in addition to the first queue under the new system. (See *Stakeholders Challenge PJM in Capacity Accreditation Talks*.)

A study of transmission headroom would be conducted each year before the BRA to determine how much is available and how to allocate it. Stakeholders questioned if alternatives have been considered for how to distribute that headroom among generators if requests for CIRs exceed the headroom available, such as prioritizing those units that would provide the most value to load.

Kern said the PJM proposal would prorate the headroom based on factors such as a facility's power flow. If a study finds a generator is close to an electrical overload, it will likely be scaled down more than other units in that area. Kern indicated PJM was considering a final approach to this type of adjustment.

Expanding the use of headroom to all resources was a compromise with generation owners who felt limiting the studies to just ELCC resources was discriminatory. Tom Hoatson of LS Power said expanding the headroom studies met one of his company's concerns with the PJM package. But he said the overriding issue is ensuring that the solution chosen is effective for next year's June auction. He said multiple auctions have been held without the issue being resolved.

"We're getting close to having a resolution; we're getting close to putting this in place," he said.

Economist Roy Shanker said it's important that any issues that come up over the coming months don't create delays that could prevent the new rules from being ready for the auction.

"It's already been three auctions where what we consider an incorrect accreditation has taken place," he said.

Ken Foladare of Tangibl said it's likely many stakeholders will remain interested in PJM's Package D, which he pushed to remain under consideration until the PC takes an endorsement vote. Three additional packages also remain: Package E from LS Power, Package F from Eolian and Package G from E-Cubed Policy Associates. (See "Poll Opened to Gather Support for Packages on CIR for ELCC Resources," *PJM PC/TEAC Briefs: Oct. 4, 2022*.)

$50M+ in Projects Reviewed by TEAC

PJM reviewed several baseline reliability projects totaling more than $40 million as part of its reliability analysis update:

purchasing a spare VAR 345-kV reactor for Penelec's 345-kV Mainesburg substation at a $6.44 million price tag.

installing two new 500-kV breakers on the existing open SVC string, which would be relocated into a new bay location at the 500-kV Black Oak substation near Rawlings, Md. The APS proposal also calls for installing a 500-kV breaker on a 500/138-kV transformer and upgrading relaying in the substation. The work is expected to cost $17.37 million with a June 1, 2027, in-service date.

Baltimore Gas and Electric and PECO Energy recommended replacing and upgrading equipment along the companies' 500-kV Peach Bottom-Conastone circuit, which is overloaded for multiple contingencies. The recommended solution for BGE's side of the work includes upgrading two breaker bushings on a Conastone substation, while the PECO work would involve replacing 4 meters and bus work inside the Peach Bottom substation. The total cost of the work is expected to fall at $5.8 million with an in-service date of Dec. 1, 2027.

PPL has identified that a stuck breaker contingency would result in the 500/230-kV Lackawanna transformer No. 3 being overloaded. The solution recommended is to re-terminate transformers Nos. 3 and 4 on the 230-kV side to remove them from the buses and into dedicated bay positions. The work is expected to cost $10.7 million with a Jan. 30, 2026, in-service date.

Jonathan Kern, PJM | © *RTO Insider LLC*

Dominion also reviewed its own supplemental projects, amounting to nearly $10 million.

Five 230-kV breakers and six disconnect switches at the company's Clover substation are at the end of their lives and experiencing increased maintenance issues and difficulty sourcing replacement parts. The work, which is in the engineering phase, is expected to cost $2.75 million with a projected in-service date of June 1, 2023.

Dominion has identified a need to replace $2.36 million in 230-kV equipment at the North Anna substation in Virginia. The work is currently in the engineering phase and is projected to be in-service on Aug. 30, 2023.

The company is seeking to replace its Davis TX#2 168-MVA, 230/69/13.2-kV transformer bank because of its 32-year age, degradation of components and the basic insulation level being below standard. The project, currently in its engineering phase, is estimated to cost $4.5 million and be completed by June 30, 2023.

Dominion has also submitted three new requests for substations in Loudoun County, each with a total load in excess of 100 MW. The company has also identified overloads on a 230-kV line on the Brambleton-Evergreen Mills for the loss of the Brambleton-Poland Road line. It is in need of a temporary solution to avoid the overload and provide flexibility for future construction outages. ■

— Devin Leith-Yessian

PJM News

PJM MIC Briefs

Examining Local Impacts on Net CONE

VALLEY FORGE, Pa. — The Market Implementation Committee last week overwhelmingly adopted a problem statement and issue charge to explore whether PJM should account for local issues, such as state and local policies, that may impact the development of the net cost of new entry (CONE) in a region.

The measure passed Wednesday with 97% of votes supporting.

While there was general agreement among stakeholders that the issue should be addressed by PJM, there were questions about how far the scope of the issue charge should go.

James Wilson, a consultant to state consumer advocates, likened making changes to the derivation of net CONE to changing the length of one leg of a stool without looking at the others, with the stool in the metaphor being the capacity market and the impact being the tilting of the markets in favor of certain sectors.

"That would cause money to slide off the stool and into their pockets," he said.

That could be mitigated by implementing the changes to net CONE in the next quadrennial review, when other factors related to the capacity market can also be considered, or by widening the issue charge.

Gary Helm, PJM | © RTO Insider LLC

Gary Helm, PJM lead market strategist, said it wasn't the RTO's intention to limit discussion and that he did not believe the stakeholder process would yield such results.

Approval to Merge DER and DIRS Subcommittees

Stakeholders approved by acclamation to support merging the Demand Response Subcommittee and the DER & Inverter-Based Resources Subcommittee into a new Distributed Resources Subcommittee (DISRS).

PJM's Peter Langbein and Scott Baker, the former chairs of the DRS and DIRS, respectively, said the stakeholder composition of the two committees and the materials they reviewed were similar enough that they conduct their work in unison. They said it would be best to work in tandem, particularly when recommending manual changes.

Monitoring Analytics President Joe Bowring | © RTO Insider LLC

The combined charter will also examine behind-the-meter generation and energy efficiency, in addition to the existing scope of the two committees: DR, distributed energy resources and inverter-based resources.

Independent Market Monitor Joseph Bowring said the committee's charge would be too broad, which could institutionalize a separate system being created for inverter-based resources. Since the resources falling under the committee are part of the capacity market, he believes they should be addressed by the existing committee structure, which handles other resources.

MIC Endorses Proposal on Hybrid Resources

The committee endorsed a proposal to expand PJM's hybrid resource rules — which are currently applicable only to solar and storage combinations — to now include all inverter-based resources (IBRs) paired with storage.

The proposal allows IBR and storage hybrids to participate in the energy market model created in the first phase of the hybrid resource design, which was implemented for classification and metering on Oct. 1. The energy market model is set to go live on June 1, 2023.

The package also broadens the definition of hybrid resources to include combinations of different types of generation, with or without storage, with the implication of allowing more resource types, such as hydro or gas paired with solar to participate under the provisions from the first phase. (See *PJM Releases Phase 2 of Energy Transition Study*.)

The language also contains clarifications to PJM's EcoMax parameters and corresponding uplift rules.

The proposal will require approval by FERC.

First Read on Changes to Day-ahead Zonal Load Bus Distribution Factors

PJM's Amanda Martin presented a first read of proposed changes to the RTO's day-ahead factor analysis, which would shift from calculating each hourly node based on state estimator load for that node as of 8:00 AM on that day of the prior week to instead use the previous week's real-time data from each hour.

For example, instead of basing expectations for 10 a.m. on Nov. 8 on 8 a.m. data from Nov. 1, the corresponding real-time data from 10 a.m. would be pulled.

The lookback period would use the most recently available day of the week where all 24 hours of data are available, meaning if an hour of data was unavailable for Nov. 1 in the previous example, that date would be skipped and data would be pulled from Oct. 25. ■

SPP News

Enable in Rear View, OGE Looks to Improve Reliability

OGE Energy management told financial analysts Thursday that it has completed its exit from the Enable Midstream Partners joint venture with the final sale of its interest units, allowing the company's investors to focus on "a premium electric utility business."

CEO Sean Trauschke did not sound disappointed during the company's third-quarter earnings call that it would be the last in which he discussed midstream financial results, saying he wanted to "take a moment to reflect on the end of what has been a decade-long effort to close this part of our business and move forward."

OGE, and CenterPoint Energy, completed a $7.2 billion sale of Enable to Energy Transfer Partners in December 2021. (See *OGE, CenterPoint Complete Enable's Disposal*.)

The company is using the proceeds from the sale to pay down short-term debt and plan for the future by protecting customers with an equal focus on reliability and affordability. It has also increased its storage positions to increase its physical supply of natural gas, one of OGE's key learnings from the February 2021 winter storm.

"At the end of the day, we're accountable to making sure that energy is flowing to all of our customers, and we want to control that," Trauschke said. "We want to make sure that we're in charge of that, and we don't want to rely on others to support us."

OGE Energy's exit from midstream gas will enable investors to focus on OG&E and its utility business. | *OG&E*

OGE reported earnings of $262.8 million ($1.31/share), as compared to $252.5 million ($1.26/share) for the same quarter a year ago, attributed mostly higher operating revenues driven by warmer weather. The earnings exceeded analysts' expectations of $1.16/share.

The company's share price was trading at $37.07 in after hours, a gain of 69 cents on the day. ■

— Tom Kleckner

SPP News

FERC Approves SPP Cost-allocation Waiver Plan

SPP Responds to Clean Energy Advocates' Protest of Self-funding Proposal

By Tom Kleckner

FERC has approved an SPP proposal that establishes a way for "byway" transmission projects to be allocated across the RTO's entire footprint on a case-by-case basis.

Under current rules, SPP allocates one-third of the cost of byway projects — lines rated at 100 to 300 kV — to the RTO's full footprint, with customers in the transmission pricing zone where the project is built being allocated the rest. "Highway" projects — those larger than 300 kV — are allocated RTO-wide.

The new process allows entities to seek exceptions to the RTO's cost-allocation process for byway facilities, addressing a growing issue for ratepayers in transmission zones where most of the power being generated is exported to other areas (*ER22-1846*).

In a 3-2 decision issued Oct. 28, the commission found that the proposal will help ensure that SPP's "byway" facility costs are allocated roughly commensurate with estimated benefits, consistent with FERC's cost-causation principle. The order is effective Aug. 1, 2022.

Commissioners James Danly and Mark Christie dissented from the order, saying it forces some states to pay for other states' renewable energy policies. Kansas was the only one of the 14 states in SPP's footprint to support the order at FERC.

Al Tamimi, vice president of transmission policy and planning for Sunflower Electric Power, said the order addresses the changes necessary to align costs and benefits for local zones with renewable energy that exceeds the zones' peak loads and is exported to other zones in SPP.

"In renewable-rich zones, the function of the byway transmission facilities has changed from mainly serving local loads to now carrying and exporting regional flows … where the byway facilities function as a regional flow carrier," Tamimi told *RTO Insider*. "Renewable-rich areas like Sunflower Electric have experienced increased costs required to build transmission infrastructure that export substantial energy to other areas of the SPP region. The majority of the transmission costs for byway transmission facilities have been shouldered by local ratepayers versus those benefiting from the energy exports."

Tamimi has been involved in finding relief for wind-rich zones since 2017. The Holistic Integrated Tariff Team in 2019 *recommended* evaluation of a narrow process through which specific projects between 100 and 300 kV could be fully allocated regionally. Transmission owners largely opposed the proposal as it wound its way through the stakeholder process, saying it would shift byway cost responsibility from wind-rich areas to others.

SPP singled out Sunflower in its request to FERC. It said the Kansas utility's pricing zone has 3,100 MW of wind but only a 900-MW peak load.

SPP's first attempt to gain approval was rejected last year by FERC over concerns the proposal granted the RTO's Board of Directors too much discretion in allocating costs and did not include clear standards for making decisions. (See *FERC Rejects SPP's Cost-allocation Waiver Proposal*.)

The majority in the Oct. 28 decision said Danly failed to identify any evidence to support his conclusion that SPP's proposal is "designed to facilitate the shifting of some states' public policy costs onto other states." The commissioners noted that 11 of SPP's 14 states do not have active renewable energy standards and that a majority of those that do not (seven out of eight) voted in favor of the measure at the Regional State Committee meeting.

"Such robust support for the proposal, including among states without public policies, strongly undercuts [Danly's] claims about improper cost shifts," the majority said. "What matters here is that SPP's proposal establishes regional cost sharing, consistent with the cost-causation principle, where the relevant infrastructure provides significant benefits to the entire region."

SPP members will now be able to apply for waivers from transmission upgrades costs for wind projects on a case-by-case basis. | *Xcel Energy*

SPP Responds to Self-funding Comments

SPP on Monday responded to a protest by a group of clean energy advocates that argues the RTO's proposal to create a standard pathway for TOs to build and profit from network upgrades necessary to bring generators online is "patently deficient" and should be rejected outright (*ER22-2968*).

The grid operator told FERC that it made clear in its original request that it was not proposing tariff revisions to provide for the TO self-funding option, given that this option already exists in its *pro forma* generator interconnection agreement. Instead, staff said, the revisions were providing details for implementing the TOs' right to elect self-funding, including a *pro forma* facilities service agreement that would promote administrative efficiency and predictability for TOs and interconnection customers.

TOs would be able to recover the self-funding network upgrade costs and a return on the investment from the interconnection customer. FERC approved a similar request by MISO in 2020 (*ER20-359*).

The American Clean Power Association, Advanced Power Alliance, Solar Energy Industries Association, Natural Resources Defense Council and Sustainable FERC Project filed the protest in October, urging the commission to reject SPP's request.

They said the RTO's proposal is "wholly unsupported" and would be unjust and unreasonable if accepted. SPP has the burden under Section 205 of the Federal Power Act to demonstrate that the proposed change is just and reasonable, they said, noting that FERC can reject a filing that "patently fails to substantially comply with the applicable requirements" of its regulations.

"SPP did not submit any information to support the proposed tariff change," the coalition said, claiming the tariff filing is "devoid" of supporting information. "The entire filing consists of a 17-page transmittal letter and the proposed revised tariff records. SPP failed to include any testimony or supporting affidavits and has failed to meet its burden under Section 205." ■

Company News

Xcel Energy to Quit Burning Coal in 2030

Utility Announces Accelerated 2028 End Date for Texas Plant

By Amanda Durish Cook

Xcel Energy last week said that it intends to retire its Tolk Generating Station in West Texas four years ahead of schedule, clearing the way to exit coal usage by the end of 2030.

Xcel said winding down Tolk's operations at its two units, with a combined capacity of 1,067 MW, early will save ratepayers more than $70 million. Tolk supplies parts of Texas and New Mexico with power. The plant faces a rapidly *depleting* supply of groundwater for its operations.

Xcel originally agreed to cut the operating life of Tolk from 2037 to 2032 in a 2020 *stipulation* over a rate increase with the New Mexico Public Regulation Commission. Under the agreement, Xcel also committed to studying at least one scenario where it would retire the plant before 2030. New Mexico has a goal to reach 100% carbon-free electricity by 2045.

The utility said it will soon file a revised retirement date with New Mexico regulators and put the plan to Texas regulators in February.

Xcel said it will continue flexible operations at Tolk, running the plant "when natural gas prices are high while managing limited remaining water resources." It also said it will run Tolk's currently installed synchronous condensers beyond 2028 to help ensure grid reliability.

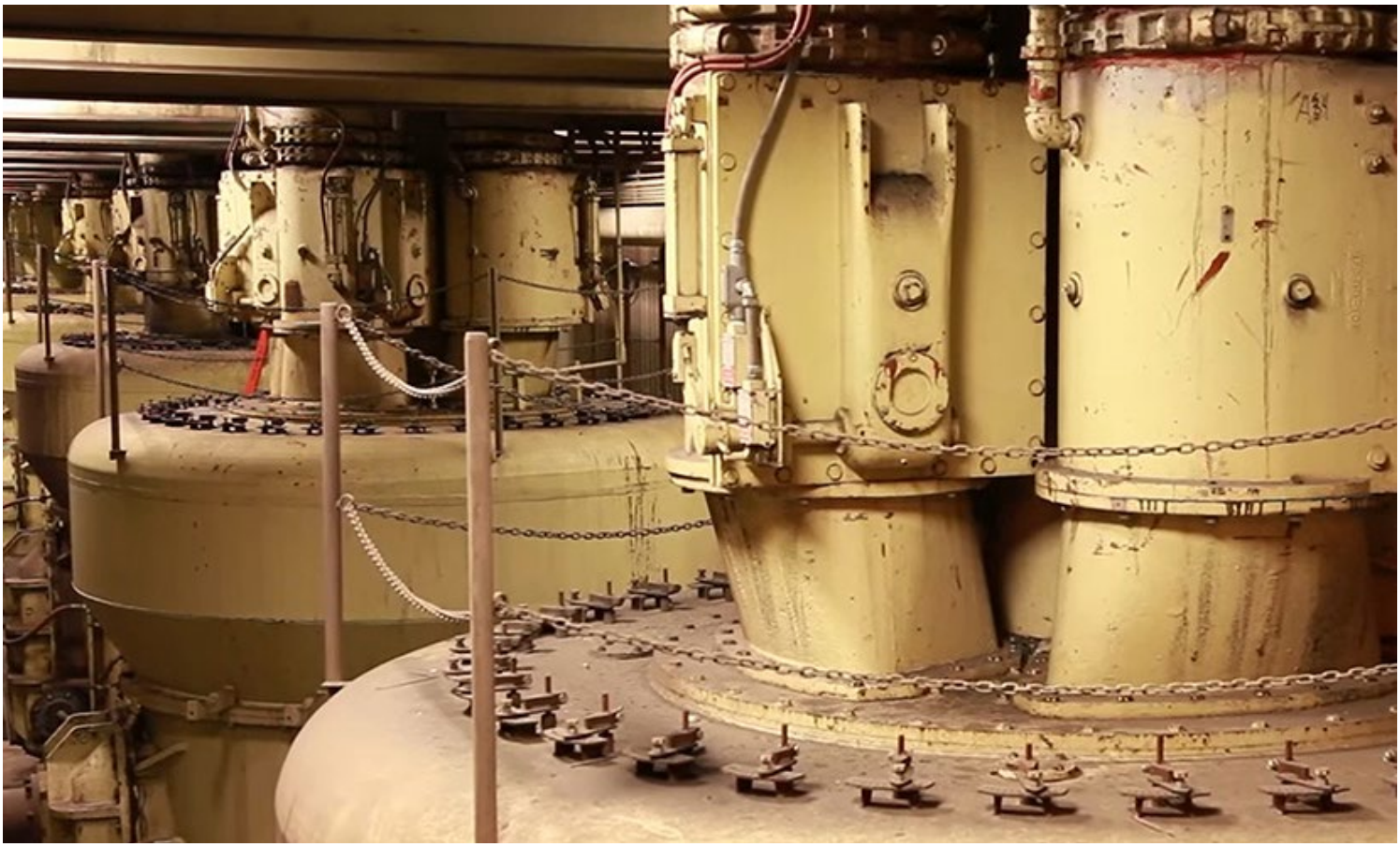
The utility said it will substitute Tolk's output with a "diverse mix of replacement generation, including wind and solar."

"For more than 40 years, the dedicated employees at Tolk Generating Station have provided reliable and safe service to our Texas and New Mexico customers and communities," said Adrian Rodriguez, president of Xcel Energy New Mexico and Texas. "While we maximize replacement generation in the region, we're also committed to transition our employees into new roles as needed, something we've done successfully at other Xcel Energy plants."

Xcel said Tolk's accelerated retirement will help meet its goal to reduce carbon emissions 80% by 2030, when its Comanche 3 coal unit, its last coal burner is retired. The company plans to generate 100% carbon-free electricity by midcentury.

"As the first energy provider in the nation to set ambitious goals for addressing all the ways our customers use energy — electricity, heating and transportation — we are always striving to provide our customers cleaner energy resources, while saving them money," Xcel Energy CEO Bob Frenzel said in a *statement*. "Advancing the retirement of coal operations at Tolk Station demonstrates our commitment to our clean energy strategy, while ensuring our customers and communities have reliable, affordable and safe service."

Three years ago, Xcel committed to retiring its two northern coal plants in the MISO footprint by 2030. (See *Xcel Latest MISO Utility to Pledge Zero Coal*.) ■



Interior of the Tolk Generating Station | *Xcel Energy*

Company Briefs

Tesla to Start Cybertruck Production by 2024

Tesla aims to start mass production of its Cybertruck at the end of 2023, two years after the initial target for the pickup truck that CEO Elon Musk unveiled in 2019, sources said.

Tesla said last month it was working on readying its Austin, Texas, plant to build the new model with "early production" set to start in the middle of 2023. A gradual ramp in the second half of next year to full output for the electric truck would mean Tesla would not be recording revenue until early 2024.

More: *Reuters*

Entergy Nuclear Announces Senior Leadership Changes

Entergy last week announced Kimberly Cook-Nelson will take over as executive vice president and chief nuclear officer in the Jackson, Miss., headquarters of the company's nuclear operations. Cook-Nelson joined Entergy in 1996 as the general manager of plant operations at Waterford 3 Steam Electric Station.

Chris Bakken, the former CNO, will move into a new position as executive vice president of infrastructure. John Dinelli will take over as nuclear chief operating officer, while Bill Maguire was named senior vice president of nuclear corporate services.

More: *Entergy*

AEP Names Kelly CFO

American Electric Power last week named Ann P. Kelly executive vice president and chief financial officer, effective Nov. 30.

Kelly will be responsible for AEP's accounting and tax, treasury and risk, corporate planning and budgeting, and investor relations functions.

Kelly is currently vice president of finance and CFO for AmeriGas Propane, a position she has held since 2019.

More: *AEP*

Federal Briefs

Interior to Pay Tribes to Move Away from Potential Climate Disasters

The Biden administration last week said it will give money to five Native American tribes to help them relocate away from rivers and coastlines.

The funding, which will go to three tribes in Alaska and two in Washington state, marks the start of a new federal program specifically designed to relocate people and homes threatened by climate change. The program could become a template for other federal agencies that work on disaster recovery. Those agencies, including the Federal Emergency Management Agency, are reconsidering the strategy of repeatedly rebuilding communities in places where they are vulnerable to floods, hurricanes and other threats.

More: *The New York Times*

Manchin Voices Displeasure with Biden's Coal Comments

Sen. **Joe Manchin** last week slammed President Biden after he called for coal plants across the U.S. to be shuttered.

While speaking in Carlsbad, Calif., Biden said, "We're going to be shutting these plants down all across America and having wind and solar."

"Comments like these are the reason the American people are losing trust in President Biden and instead believes he does not understand the need to have an all-in energy policy that would keep our nation totally energy independent and secure," Manchin said. "It seems his positions change depending on the audience and the politics of the day. Politicizing our nation's energy policies would only bring higher prices and more pain for the American people.

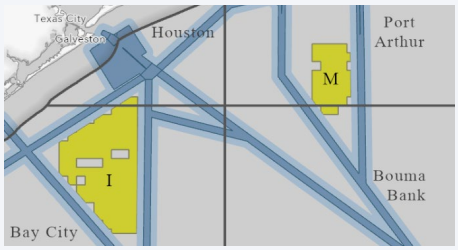
"Being cavalier about the loss of coal jobs for men and women in West Virginia and across the country who literally put their lives on the line to help build and power this country is offensive and disgusting. The president owes these incredible workers an immediate and public apology, and it is time he learned a lesson that his words matter and have consequences," Manchin said.

More: *CNN*

BOEM Designates 2 Wind Energy Areas in Gulf of Mexico

As part of the Biden administration's goal of deploying 30 GW of offshore wind energy capacity by 2030, the Bureau of Ocean Energy Management (BOEM) last week announced two Wind Energy Areas (WEAs) in the Gulf of Mexico.

The first WEA is located 24 nautical miles off the coast of Galveston, Texas, and has an area of 508,265 acres. The second WEA is



located 56 nautical miles off Lake Charles, La., and totals 174,275 acres.

BOEM collaborated with the National Oceanic and Atmospheric Administration to build an ocean model that analyzed the entire Gulf of Mexico ecosystem to find areas that have the least conflict with other uses and the lowest environmental impact.

More: *BOEM*

State Briefs

CALIFORNIA

PG&E Moves to Extend Life of Diablo Canyon

PG&E last week formally asked the Nuclear Regulatory Commission to extend the life of Diablo Canyon, the last operating nuclear plant in the state, as part of Gov. Gavin Newsom's effort to improve reliability of the grid.

PG&E said it applied to renew Diablo Canyon's license and postpone its planned 2025 shutdown. The plant supplies about 9% of the state's power.

Newsom signed legislation in September that would keep the plant open until 2030 and allow the state to loan PG&E as much as $1.4 billion to make needed upgrades to postpone the closure.

More: *The Sacramento Bee*

COLORADO

Xcel Cancels Plan for Unaweep Canyon Hydropower Project

Xcel Energy last week told FERC it was withdrawing its application for a preliminary permit for a two-reservoir, pumped-storage hydropower plant in the rural western Colorado Unaweep Canyon.

FERC had accepted Xcel's Public Service Company of Colorado preliminary permit application earlier in the week, giving the utility the ability to further study the plan. However, Xcel spokeswoman Michelle Aguayo said the utility had identified "multiple concerns" in Unaweep Canyon and the location "is no longer being considered."

Xcel in August 2021 filed an application for a preliminary permit for a pumped-storage hydropower plant in the canyon and proposed spending as much as $1.6 billion on the project. Pumping the water to the top reservoir during the day would have used more power than the turbines generated, but the power from the project would generate electricity on demand when other renewable sources would be ebbing.

More: *The Colorado Sun*

IOWA

Report: Toxic Pollutants Leaking from Coal Storage Sites

Twelve sites that store coal ash are leaching toxic pollutants into the environment, said a new report released last week by nonprofits Environmental Integrity Project and Earthjustice.

Alliant Energy and MidAmerican Energy, operators at some of the 12 Iowa sites named in the report, said they are already following the EPA's standards and regulations for coal ash disposal. Under the coal ash rule, every coal plant owner is required to monitor nearby groundwater and publicly report the data.

The report said the sites are among at least 265 coal-fired plants across the United States contaminating groundwater, representing 91% of the nearly 300 evaluated sites. Coal ash contains toxic pollutants that can cause cancer and bodily and neurological damage.

More: *The Gazette*

NEW MEXICO

Supreme Court Pauses Rate Credits for PNM Customers

The state Supreme Court last week granted the Public Service Company of New Mexico a stay in its appeal of an order from the Public Regulation Commission regarding rate credits.

Earlier this year, the PRC ordered PNM to issue rate credits to prevent customers from paying for the operations of the now-closed San Juan Generating Station that customers no longer benefit from. PNM then appealed the order to the Supreme Court and asked it to stay the implementation of the rate credits until after the case is resolved.

PNM argued that the cost of doing business has gone up and that by not issuing the rate credits the utility can invest that money in other areas. The utility plans to remove the costs associated with the San Juan station from rates during the next rate case. PNM said in its appeal that not issuing a stay of the credits would result in the company losing more than $128 million in revenue.

More: *NM Political Report*

NORTH CAROLINA

Duke Cleared to Add 1,200 MW of Solar Capacity

The Utilities Commission last week issued an order authorizing Duke Energy to add 1,200 MW of solar capacity this year through purchase agreements with developers.

Duke will have to do its own evaluations to narrow its new partnerships to 1,200 MW. The company has received 64 eligible solar proposals totaling nearly 5,000 MW.

The annual allotment is tied to a solar procurement program overseen by the commission and aimed at moving the state toward emissions targets established in climate legislation passed by the General Assembly and signed by Gov. Roy Cooper in October 2021.

More: *Winston-Salem Journal*

NORTH DAKOTA

PSC Chair to Recuse Self from CO2 Pipeline Siting

Public Service Commission Chair **Julie Fedorchak** last week recused herself from any siting decisions on the proposed Summit Carbon Solutions CO_2 pipeline.

Fedorchak said she and her husband own land in Oliver County. A year ago, they signed a contract with Summit to store CO_2 on their land. She said she wants to avoid any perceived conflict of interest in the case.

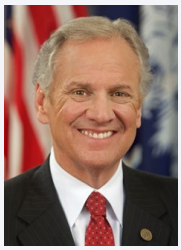
The project is designed to capture CO_2 emissions from ethanol plants in the

Midwest and have them sequestered in the state.

More: *Prairie Public Broadcasting*

SOUTH CAROLINA

Ecoplexus to Invest in Solar Farm



Gov. **Henry McMaster's** office last week announced an $89 million investment by international renewable company Ecoplexus for a solar farm in Newberry County.

The 75-MW solar farm is expected to come online in 2025.

The company is also developing a 75-MW solar project in Williamsburg County that is expected to be operational in the second quarter of 2023.

More: *The State*

VIRGINIA

Pulaski County Denies Solar Farm Permit

Pulaski County Board of Supervisors last week unanimously denied a permit for Helios Solar farm, citing environmental concerns with the solar panel material and landscaping that would be required.

Chair Laura Walters noted mixed research on the panels but ultimately voted to deny the permit due to environmental concerns. Her concern stems from the fact the panels are made from a relatively new process that includes cadmium telluride.

More: *Southwest Times*

SCC to Hold Hearing on Consumer Protection for OSW Project

The State Corporation Commission has set a Nov. 21 date for a hearing regarding a consumer protection agreement for Dominion Energy's proposed $9 billion offshore wind project.

The new proposal, which follows months of back-and-forth between Dominion and the SCC, will set a cap on any cost overruns that could be passed on to ratepayers if the 176-turbine project doesn't perform as expected. When the SCC first granted an order to Dominion on Aug. 5, it included a performance standard to protect consumers that the utility later claimed would threaten the viability of the project.

Should the wind farm's output fail to hit a net capacity factor of 42% in a three-year rolling average, the SCC would step in to ask why. From there, the commission could decide on a solution if it found the problem to be caused by "unreasonable or imprudent actions" by Dominion. The agreement also limits ratepayers' responsibility. If the cost of the project exceeds $9.8 billion, additional costs of up to a total of $10.3 billion would fall on Dominion's ratepayers.

More: *Richmond Times-Dispatch*

WASHINGTON

New Homes, Apartments Must Use Heat Pumps

The Building Code Council last week voted 9-5 to require all new homes and apartments to use heat pump systems to reduce carbon emissions.

The council voted in April to require new commercial construction to switch to heat pumps. Now, home builders will be required to follow the same rules with new construction starting next year.

The council's approval of the rule starts a process of writing a final rule, which is scheduled to be complete sometime in mid-January. The code takes effect July 1.

More: *The Spokesman-Review*

National/Federal news from our other channels

States to Receive $9B from IRA to Boost Home Efficiency Upgrades — NetZero Insider

COP27: Will Countries Step up on Climate, Financial Commitments? — NetZero Insider

A New Era for Climate Action at COP27: 'We Will be Holding People to Account' — NetZero Insider

Guterres Tells COP27: 'We're on a Highway to Climate Hell' — NetZero Insider

FERC Approves Penalties in SERC, RF Footprints — ERO Insider

NERC's DER Strategy Focuses on Industry Education, Collaboration — ERO Insider

FERC Orders Clarification in ERO Budget Filing — ERO Insider

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