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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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RTO Insider
Your Eyes and Ears on the Organized Electric Markets
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In this week's issue

FERC/Federal News

RTOs Seek More Flexible Compliance in Appeal of EPA Power Plant Rule

By James Downing

ERCOT, MISO, PJM and SPP last week filed a joint brief in the appeal of EPA's power plant rule seeking more flexibility on compliance, arguing it is needed to ensure reliability. (See *Republican-led States Sue EPA over Power Plant Emissions Rule*.)

The four grid operators submitted comments similar to those they made while the agency was working on the rule. (See *EPA Power Plant Proposal Gets Mixed Reception in Comments*.)

"Without additional modification, the compliance timelines and related provisions of the rule are not workable and are destined to trigger an acceleration in the pace of premature retirements of electric generation units that possess critical reliability attributes at the very time when such generation is needed to support ever-increasing electricity demand because of the growth of the digital economy and the need to ensure adequate backup generation to support an increasing amount of intermittent renewable generation," they wrote. EPA's final rule would strain their ability to maintain the reliability of the electric grid, they argued.

The grid operators had proposed a "reliability safety valve" that would help mitigate their concerns, but EPA did not include that in the final rule, nor did it explain why, they noted. The grid operators had wanted EPA to provide upfront, clear criteria on the "remaining use of life and other factors" and enforcement discretion; the creation of a subcategory of generators needed for reliability; offering states guidance on how to use a reliability valve; and the creation of "regional reliability allowances" that generators could use in emergencies to avoid penalties under the rule.

Instead, they argued, the final rule unreasonably discounts that existing fossil generators will need to decide whether to commit to installing untested technology or retire their units years before the compliance deadline with state compliance proposals due in 2026. That could accelerate earlier retirements of generators, the grid operators said.

The rule requires 90% carbon capture and storage for coal plants that want to run after Jan. 1, 2039, as well as for new and modified natural gas units with capacity factors of 40% and above. Both categories of plants would need to install CCS systems by Jan. 1, 2032.


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"None of EPA's projected time frames reflect historical rates of adoption of CCS technology for electrical generation purposes, nor does EPA adequately consider the risks that the technologies will not mature in time for [electric generating unit] owners to deploy them," the grid operators said.

EPA's rule did include a short-term reliability mechanism, which requires the declaration of an energy emergency alert 2 before any compliance mitigation can take place.

"This short-term reliability mechanism that EPA did adopt in the rule thus unduly places the grid — and customers — at greater risk before any short-term relief would be available," the grid operators said. They "should not have to wait until the heightened level of emergency that an EEA2 declaration represents; they should be able to take proactive measures to address reliability issues upon earlier evidence of deteriorating grid conditions as evidenced by declaration of an energy emergency alert 1."

Compliance flexibility should kick in at EEA 1 because at that point, grid operators can still call on emergency generation. By waiting until an EEA 2, grid operators cannot act until they are in a real-time emergency.

For longer-term issues, states can ask for extended deadlines or lower technology standards, but the grid operators would like to see EPA offer more guidance on that process.

EPA is not responding to the initial briefs until next month, but the RTOs' comments did generate some response from others. The Clean Air Task Force and Natural Resources Defense Council filed lengthy *comments* on grid reliability, arguing the rule was designed to give utilities and system operators the flexibility they need to maintain grid reliability.

"While EPA has considered reliability issues in its proposal, FERC is the agency with direct jurisdiction over electric reliability," the organizations said. "As discussed above and as recognized by FERC, the electric grid is undergoing changes unrelated to the EPA proposal, and the proposed regulations are only incremental to these existing forces. FERC and the electric utilities have the responsibility and many tools available to them to ensure reliability as these grid changes occur." ■

FERC/Federal News

DOE, PNNL Initiative to Focus on Equity in Tx Planning

Inclusive Transmission Planning Program Will Prioritize RTO, ISO Participation

By K Kaufmann

Equity and community engagement have not been high priorities for the RTOs, ISOs, utilities and other organizations that have primary responsibility for planning the nation's transmission system — a situation that historically has resulted in siting and permitting delays and, in some cases, yearslong litigation.

But the U.S. Department of Energy and Pacific Northwest National Laboratory (PNNL) want to change that narrative with a new initiative — the Inclusive Transmission Planning (ITP) project — which will provide technical assistance to grid planners seeking to integrate equity and community input into their projects up front, rather than as an add-on.

Speaking at a Sept. 17 webinar on the ITP, Emma Hibbard, a technical adviser in DOE's Grid Deployment Office, laid out the rationale for the new program.

"Timely transmission deployment is essential to increase grid reliability and resilience and lower costs for consumers, as well as pave the way to a clean energy future, but often public acceptance of new transmission development can constrain [or] delay deployment," Hibbard said. "There's also an increasing awareness that positive outcomes for transmission development really hinge on ensuring positive and equitable outcomes for all, including disadvantaged and rural communities along transmission routes."

Hibbard acknowledged that FERC, state regulators and many grid planners are working to improve transparency and public participation. But, she said, "there's a need for more information and more support around energy equity and the relationship to transmission planning, and … new approaches to soliciting and integrating community input, in addition to what is already existing."

The webinar provided an overview of the ITP program, which is offering two tracks of technical assistance — but no funding — for grid planning organizations.

"Tier 1 is really about education, outreach and capacity building," said Paul Wetherbee, an adviser on regional energy system planning at PNNL. "We're really talking about educating and building awareness of energy equity concepts" — for example, providing a presentation "describing the main pillars of energy equity

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and how they would fit into the transmission planning process, or how to think about that in terms of your existing transmission planning processes."

In Tier 2, "we're going to do a deep dive with the applicant into the pool and go into some of [the] details of other transmission planning processes and metrics," Wetherbee said. Topics "might include developing quantitative energy equity metrics, putting that together with the existing data sets and working with the applicant to go through their current … transmission planning metrics" and cover energy equity measures.

Tier 2 could also look at how to integrate energy equity into cost allocation metrics and transmission economics, he said.

Both tracks will incorporate three components, said Jennifer Yoshimura, the principal investigator for the program at PNNL. A series of listening sessions will begin in October to gather input from a broad range of stakeholders "to understand opportunities for participation as well as barriers," Yoshimura said. The *listening sessions* for transmission planners are scheduled for Oct. 1 and Oct. 16.

The ITP will also develop research and resource materials for the general public as well as grid planners "to increase inclusivity as well as equitable outcomes," she said. The technical assistance component will focus on "capacity building for transmission planners to look at how to incorporate energy equity and justice objectives within their planning processes and paradigms."

Applications for the program are now open, with a final deadline of Oct. 31, Wetherbee said. Applications will be reviewed in November, and program participants will be announced in December. Both tiers will kick off in January 2025 and run through November.

Eligibility is strictly limited to grid planning organizations, including RTOs, ISOs, utilities and power marketing administrations, such as the Bonneville Power Administration, but DOE and PNNL are looking for diverse participants

FERC/Federal News

for each tier, based on geography and equity issues, Wetherbee said.

Tribes often do not have dedicated grid planners, but DOE on Sept. 17 also announced a *Tribal Nation Transmission Program*, which will provide "educational resources, training and on-call assistance from technical experts and researchers from the National Renewable Energy Laboratory."

'We Didn't Start with Equity'

The historic and ongoing challenges for new approaches to inclusive grid planning are complex, Yoshimura said in her opening remarks at the webinar.

Traditional industry metrics — such as the System Average Interruption Duration Index, or SAIDI — focus on "system averages that can hide vulnerabilities at the household level," she said. "We see an increase of threats and vulnerabilities involved, whether individuals with ill intentions to harm substations or transmission lines [at risk from] increasing wildfires. …

"Within transmission planning processes, we have seen an emphasis and research focusing on integrated distribution planning, as well as energy transitions on the generation side. But there are a lot of opportunities still needed to include equity and equity objectives within transmission planning" in ways that drill down to the granular, household level.

A question-and-answer session following the official presentation reflected some of the challenges ahead.

One participant asked if the ITP program would address ways to improve the National Environmental Policy Act process, the environmental reviews that can slow down and delay the siting and permitting of transmission projects.

Bethel Tarekegne, a PNNL research engineer, said whether the program would cover NEPA was still being discussed, while Yoshimura stressed that NEPA reviews are primarily part of siting and permitting processes, not planning. The Grid Deployment Office has other programs focused on siting and permitting, she said.

DOE and PNNL staff also were asked if they could provide any examples of transmission planning that resulted in equitable participation or outcomes, but none of them could.

"A lot of transmission today is really built around reliability, economics and public policy," said Patrick Maloney, a power system engineer at PNNL. Lacking examples, he suggested that "allocation of costs might be thought of as a way to bring some equity into the transmission planning process."

Yoshimura also came up empty on examples. "Our systems and institutions and policies, we didn't start with equity, yet we're trying to get to equitable outcomes," she said. "And so, I think projects like this, listening sessions, case studies and how we learn from each other will help us move in the direction that we need." ■

FERC/Federal News

MIT Report Proposes Policies to Grow Use of Advanced Tx Technologies

By James Downing

Advanced transmission technologies (ATTs) can help utilities meet the rising levels of demand that are stressing the grid, according to a *report* released Sept. 17 by the Massachusetts Institute of Technology's Center for Energy and Environmental Policy Research (CEEPR).

ATTs are a suite of technologies that include grid-enhancing technologies (GETs). The most widely used ones are dynamic line ratings, advanced power flow control devices, topology optimization and high-performance conductors.

"Increased use of advanced transmission technologies can play a major role in meeting this demand growth quickly and cost effectively," the report says. "However, electricity market structures — which disincentivize investment in innovation — are impeding progress towards modernizing the electric grid."

"A Roadmap for Advanced Transmission Technology Adoption" was written by Grid Strategies President Rob Gramlich, along with CEEPR Fellow Brian Deese and Research Associate Anna Pasnau, both of whom previously worked at the White House for President Joe Biden.

The technologies have been used for decades and are more widely deployed abroad. In the U.S., the lack of incentives for transmission providers, information provided to regulators and some features of electricity markets hold them back, according to the report. The profit structure of electricity markets does not offer the right incentives for transmission providers to adopt many forms of ATTs, despite their consumer benefits and the ability to quickly add transmission capacity to the grid, it says.

"Under the current electricity industry regulatory structure, utilities earn profits from capital expenditures, meaning that they are incentivized to make more costly capital investments (e.g., building a new power plant) over changing their operating expenses or lowering and smoothing demand for electricity — even when those capital expenditures ultimately increase costs for consumers," the report says.

The "capex bias" is an accepted and well-known feature of cost-of-service regulation, according to the report. It disincentives utilities from deploying GETs because they would avoid the need to invest in new transmission — cutting their capital expenditures and thus their profits. Part of regulators' job is to prevent utilities from taking advantage of that bias and ensure investments are in line with consumer interests, the report says.

"However, both transmission providers and regulators can struggle to identify the best way to expand capacity against a backdrop of multiple options, and for some technologies, they need new modeling practices to assess benefits," the report says. "Transmission providers and their regulators have historically focused their cost-benefit analyses on a narrow set of risks and thus are slow to scale innovations, preferring the status quo."

Some policies around ATTs have already improved, with states passing laws aimed at encouraging them, the report notes. Other policies have sought to align utility incentives with key performance metrics; FERC Order 1920 requires transmission providers to consider ATTs in the planning process.

Those steps are in the right direction, but the paper proposes five more to spread the use of ATTs across the grid:

- Regulators should require the use of ATTs in certain contexts, with the paper suggesting FERC require DLRs on highly congested lines to increase their capacity at one-tenth the cost of reconductoring. The Department of Energy should adopt a national conductor efficiency standard, which would ensure utilities use more efficient lines that can cut line losses by 30%.
- Transmission providers and regulators should have to conduct robust analyses of the value of ATTs for the electric grid. Order 1920 requires they be considered, but it lacks specificity on how robust of an analysis will be required. The paper suggests states adopt laws requiring more stringent analyses to complement the FERC rule.
- FERC should create financial incentives for transmission providers to adopt ATTs where they provide high benefits. The commission should adopt a shared-savings incentive nationally, giving utilities a cut of ratepayer savings from GETs adoption, and where possible state legislators should authorize additional returns on equity for ATT investments.
- The commission should require transmission providers to share additional information publicly so third parties can evaluate ATT adoption and hold utilities accountable when they fail to make sensible investments.
- FERC should open up the planning process for a third party to work on deploying ATTs. The paper suggests the commission could require transmission providers to release relevant data to the National Renewable Energy Laboratory, or another qualified nonprofit entity, to come up with plans for each grid operator to adopt ATTs and update them on a regular basis. ■

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FERC to Consider Special Interconnection Rules for Tribal Energy Projects

By James Downing

WASHINGTON — FERC said it will work with federally recognized tribes on whether it needs to issue a new rulemaking to address the issues they have interconnecting renewable resources to the grid.

The announcement at the commission's Sept. 19 open meeting comes just over a month after the Alliance for Tribal Clean Energy filed a petition for an expedited rulemaking on the subject, arguing the few tribes able to build major generation projects face unique issues in hooking them up to the grid (*RM24-9*).

"This will be the first time that the commission engages in tribal consultation on an electric markets issue," FERC Chair Willie Phillips said at the meeting. "Improving the commission's tribal engagement and consultation practices is one of my top priorities and a commitment that's reflected in our equity action plan."

FERC is offering all its staff a training opportunity with Maranda Compton, an expert on tribal legal issues and a citizen of the Delaware Tribe of Indians, Phillips said.

The alliance argued that some FERC standard rules, such as commercial-readiness deposit requirements and withdrawal penalties, do not make sense with its members' projects.

"Tribal projects that advance to the point of seeking interconnection are not speculative," the tribes said. "They are not undertaken to take a big risk in hopes of making a big profit. They are not motivated to take advantage of fluctuations in the market. They are pursued to self-serve tribal needs for electricity to advance the goals of lower electricity rates, revenue for tribal governments, tribal economic development and tribal self-sufficiency."

Tribal lands are home to some of the best energy resources in the country, but on average, they pay some of the highest energy rates, with 56% paying more than double the national average, they said.

"While tribal nations are eager — indeed, desperate — to change their economic predicament and energy circumstances, they find themselves stymied by unworkable and unduly burdensome rules that fail to account for tribal nations' unique organizational structures and funding constraints," they said.

| American Clean Power Association

Building utility-scale generation projects can help redress tribal poverty and energy inequity through economic development, creating revenue and jobs, and promoting self-sufficiency, they wrote. They asked FERC to adopt limited and narrowly tailored commercial-readiness and withdrawal penalty rules that reflect their financial barriers, such as not being able to take out loans on land they hold in common among all their citizens.

The issue also came up at the recent technical conference on interconnection, during which the Oceti Sakowin Power Authority's general counsel, Jonathan Canis, described the difficulties in trying to get a major project connected to the grid.

The power authority is owned jointly by seven Sioux tribes and is trying to build two wind farms in western South Dakota, which is a high-voltage transmission "desert," Canis said. Interconnection studies would have the authority pay $250 million for the transmission on its own.

"Of course, that made our projects economically infeasible," Canis said. "To put it in perspective, our entire estimated budget for development and construction for two wind farms is $1.1 billion, so this increased our total project cost by 20 to 25%. We had to withdraw from the queue, and our projects are now on hold. We're focused 100% on how to get back in there and how to make it affordable."

The authority worked with the Western Area Power Administration and Basin Electric Power Cooperative to develop a transmission solution, a 700-mile 345-kV project that would cross Sioux land. But only parts of it were picked by SPP for the regional transmission plan, and those do not touch tribal lands, Canis said.

The Department of Energy's Loan Programs Office also has the funding for tribal energy projects, but that has never been used, outside of one commitment of $74 million for a solar microgrid to serve a big casino, Canis said.

"We're going to ask Congress to repurpose that fund to another DOE office that will really put that money to work," Canis said. "And to put it in perspective, there's only about five tribal development companies in the country, and there are not that many tribes with enough land area to develop their own wind farms. So, a fraction of that $20 billion could fix all our problems." ■

DC Circuit Orders Could Lead FERC to Rethink its Natural Gas Policies

By James Downing

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WASHINGTON — A pair of recent appeals court decisions signal a shift in how the courts view FERC's approvals of natural gas infrastructure and has the commission considering its next steps, Chair Willie Phillips said at its open meeting Sept. 19.

The D.C. Circuit Court of Appeals issued a decision in late July vacating FERC's approval of Transcontinental Gas Pipe Line Co.'s Regional Energy Access (REA) Expansion Project to bring gas from Pennsylvania to New Jersey. (See *DC Circuit Vacates Pipeline Approval FERC Issued over NJ's Objections*.)

About a week later, the court vacated FERC's approval of two LNG export facilities planned to be built near each other on Texas' Gulf Coast. (See *DC Circuit Vacates FERC Approval of Two LNG Facilities in Texas*.)

Transco has asked for rehearing on its pipeline certificate and has also filed for a temporary, emergency *certificate* so it can keep operating the REA pipeline after the court's mandate is issued, which could happen as early as Sept. 20.

"While I'm not going to prejudge what we will say in that particular proceeding, I want to make clear that I think the court erred in vacating our authorization," Phillips said. "Transco took steps to build out its system and begin serving customers."

Right after Phillips made that comment, a protester against FERC's natural gas policies stood up and started interrupting the meeting, which happened several times during the proceedings.

The court did not consider how disruptive the vacatur of FERC's approval would be on the pipeline's customers, Phillips continued after the protester was escorted out of the hearing room. Old Dominion Electric Cooperative has already filed comments in support of Transco's emergency petition, saying the firm service it uses to fuel the 980-MW Wildcat Point combined cycle plant could be interrupted.

The decision that vacated FERC's approval of the Rio Grande and Texas LNG projects is up in the air as their developers consider appeals, so no mandate will be issued until that process plays out. FERC is conducting new environmental impact statements on the projects, it said in filings issued Sept. 13.

FERC has won some cases on pipeline issues since Phillips became chair, but he said at his post-meeting press conference that the two decisions represent a break from the past.

"This is clearly a shift in the legal landscape regarding these cases," Phillips said. "What I focus on, though, is we have new commissioners who are here — who are voting ... today for the first time — that I look forward to working with on bipartisan and legally durable ways forward to address these pressing issues."

The new EISes from the two LNG facilities are going to be reviewed in the coming months, with Phillips saying they should be done by summer 2025, at which point FERC will be able to respond remanded issues from the case.

The Transco case was approved because the firm found some customers willing to sign up for service on its expanded pipeline, but that was over the objections of the New Jersey Board of Public Utilities and other state agencies who argued the gas would not be needed. The BPU filed a study saying the state had ample gas for this decade and that in the long term, its climate policies will lead to reduced demand for the fuel. But those arguments ultimately lost out.

Phillips explained how such state policies impact FERC decisions at the press conference.

"It's a matter of a balance test that we use when we consider the need, and we also consider the arguments for and against any proceeding, including our natural gas pipeline cases," he said. "We consider what the states want; we give it due consideration, as we do with all arguments raised."

The two court cases could lead FERC to again reconsider its 1999 policy statement on natural gas infrastructure approvals, which former Chair Richard Glick attempted before being rebuked by legislators on Capitol Hill, including the retiring Energy and Natural Resources Committee Chair Joe Manchin (I-W.Va.), who later refused to hold hearings on his renomination, effectively ending his term.

"The shift that we've seen in the legal landscape regarding our certifications, on LNG in particular, I think does present an opportunity for us to revisit the 25-year-old policies that we have regarding those authorizations," Phillips said. "To be clear, we have new colleagues. They've just gotten here. We certainly want to give them an opportunity to get up to speed on these matters. I've already begun conversations talking about this, interconnection [and] all the other priorities that we know that we have to deal with, but we are working toward it. This is something that is top of mind." ■

FERC/Federal News

Berkeley Lab: Solar-storage Hybrids Reshaping the Grid

Report Provides Data on Hybrid Plants in US

By K Kaufmann

Hybrid power plants, especially projects combining solar and storage, represent a growing amount of new generation online and in interconnection queues across the U.S., signaling a shift in how renewable power can be integrated into electric power markets, according to a *new report* from the Lawrence Berkeley National Laboratory.

As of the end of 2023, the U.S. had 469 hybrid power plants of 1 MW or greater, with a total of 49 GW of generating capacity and 9.9 GW of storage, the report says, drawing on information from the Energy Information Administration. Solar-and-storage projects made up 288, or more than 60%, of that total, with 14.4 GW of generation and 7.7 GW of storage.

Other topline numbers show that 66 of the 80 new hybrid plants coming online last year were solar-and-storage. Such hybrids also account for 55% of solar generation capacity and 52% of storage capacity actively moving through interconnection queues.

According to LBNL, as of the end of 2023, 2,532 solar-and-storage hybrids with more than 575 GW of power were in U.S. interconnection queues.

Further, the report notes that 46% of all online storage capacity is now coming from hybrid plants versus 42% from standalone projects. In terms of energy — actual megawatt-hours produced — hybrid storage is outperforming standalone, 52% to 38%.

Will Gorman, a research scientist at LBNL and lead author of the report, said the emergence of hybrid solar-and-storage is a relatively new trend over the past few years, spurred by the increase in solar on the grid, especially in places like California and Texas.

"There is a certain appetite for PV to just come onto the system without any kind of storage getting paired," Gorman said in an interview with *RTO Insider*. "But once you get to a certain saturation point, which we certainly have started to see in California ... you see that solar in particular is very synergistic with batteries."

Solar currently generates about *30%* of California's electricity, according to the Solar Energy Industries Association.

Market saturation, along with falling battery prices, has triggered an inflection point, Gorman said, "and it was like, 'Oh wow, we can basically create a dispatchable generator in a way, by pairing these two resources [at] a fairly competitively priced amount that wasn't really possible three or four years ago.'"

With solar providing an increasing amount of new generation on the grid — *54% in 2023*, according to the National Renewable Energy Laboratory — Gorman estimates that solar-and-storage hybrids made up about 25 to 30% of that new solar. California and Texas have the most hybrid capacity, but Massachusetts has the highest number of solar-and-storage hybrids — 89 — although they are smaller plants, with a total capacity of less than 7 MW.

Slate solar-and-storage project in Kings County, Calif. | *Goldman-Sachs Renewables*

Why It's Important

Add storage to a solar project and you have a dispatchable, flexible resource that in many cases can replace the need for natural gas peakers.

California's 72 hybrids include 30 projects with more than 100 MW of solar; for example, the Slate solar-and-storage project, which came online in Kings County in 2022, has 390 MW of solar and 140 MW of storage with four hours of duration.

Arizona led the nation for new solar-and-storage hybrids in 2023, with 16 plants coming online.

In addition to solar and storage, the LBNL report includes a long list of other types of hybrid plants in operation, including wind and storage (19 projects), fossil fuels and storage (28), nuclear and fossil (four), and geothermal and solar (seven). Hydropower paired with biomass, fossil fuels or storage is also on the list, as are triple combinations such as wind, solar and storage, and geothermal, PV and concentrated solar power.

Hybrid Synergies

As noted by Gorman, the emergence of hybrid plants has paralleled the growth of renewables on the grid and the need for new carbon-free resources that can provide the grid services, flexibility and dispatchability of traditional generation, such as natural gas peaker plants.

Federal tax credits — or rather, the lack of them — were another early driver. Prior to the passage of the Inflation Reduction Act in 2022, a tax credit for standalone storage did not exist. To cash in on the 30% federal investment tax credit (ITC) for solar, storage had to be connected to a solar project where it could charge off the PV panels at least 75% of the time.

The IRA provided a 30% ITC for standalone storage, similar to the solar tax credit. But,

FERC/Federal News

Gorman said, the ongoing growth of PV-and-storage projects could indicate that the hybrid trend is not "just some type of tax-driven construct. There are real synergies behind the things that are getting paired and extracting value from the markets we've set up."

The report tracks key data points that reflect evolving market dynamics.

Solar-and-storage projects generally have a higher ratio of storage to generation than other hybrids. Gorman defines a project's "storage-to-generation ratio" as the amount of storage per 1 MW of generation capacity. In the LBNL report, the storage ratio for PV-and-storage projects averages out to 54%, versus 18% for wind-and-storage hybrids and 21% for fossil fuels and storage.

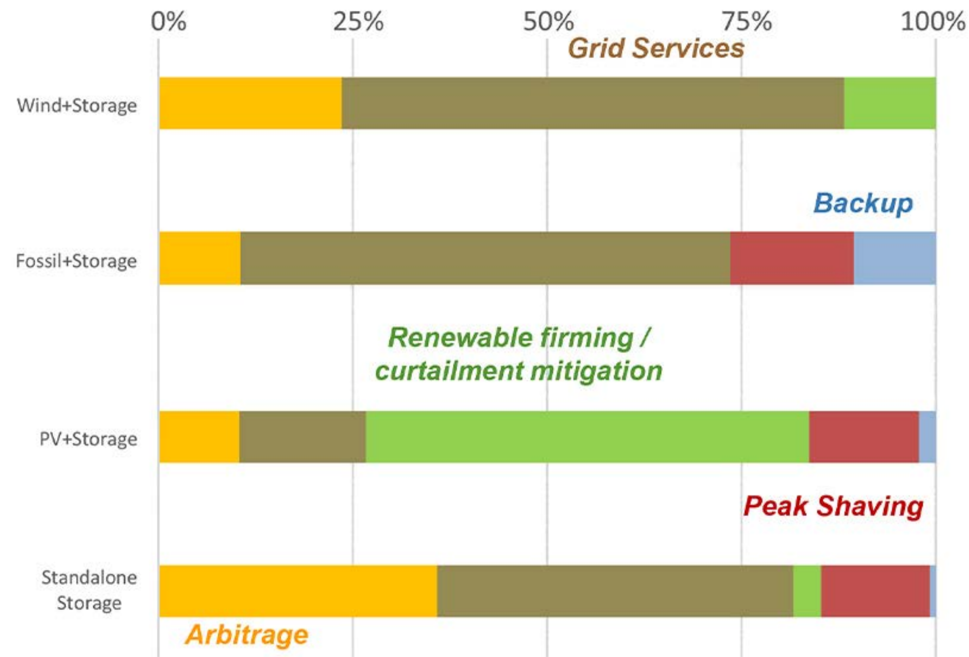
The higher ratio means these projects can store more of the excess solar energy produced at off-peak times to meet demand during peak load times, Gorman said. "You need more storage capacity to be able to absorb more of that solar energy," he said.

The higher storage capacity of these projects is also leveraged in how they are used. While many solar-and-storage plants are designed to take advantage of multiple uses and revenue streams, the report notes that in 2023, EIA started asking hybrid plant operators to provide information on their projects' primary use.

Grid services — an umbrella term covering frequency regulation, ramping, load following and voltage support — were the top primary use for most hybrids, except solar-and-storage projects, the report says. The primary use there has been system firming for renewable power and minimizing curtailment, while standalone storage projects are increasingly being used for arbitrage.

Gorman again sees the difference as a result of market evolution: Being able to time-shift power from off-peak to peak demand hours is increasingly valuable. "In the past, batteries were mostly providing these kind of reserve values, providing grid services available on demand," he said. "Now that [developers] have started to see some price differentials in the markets that are beneficial to arbitrage, they've added daily cycling on top of that."

At the same time, prices on power purchase agreements for solar-and-storage hybrids are going up in line with their increased value on the grid, as well as the impacts of inflation and supply chain constraints that have affected solar and storage in general. From 2018 through 2021, PPA prices were relatively flat, coming in around $40/MWh, Gorman said. But prices have edged up since 2022, moving toward $60 to $80/MWh.



Grid services are the primary use for hybrid power plants, except for PV-and-storage projects, which are increasingly being used to firm renewable power and minimize the need for curtailment. | *Lawrence Berkeley National Lab*

But Gorman cautioned that PPA prices "don't reflect costs. PPA prices are a mixture of supply and demand." If demand for battery storage goes up, he said, hybrid solar-and-storage projects may be perceived as more valuable.

Capacity Markets and Queues

In addition to the IRA, expansion of the hybrid market could also be affected by *FERC Order 2023*, issued in July 2023, the report says. The order allows more than one form of generation or storage to co-locate on a single site with a single point of interconnection and be treated as a single project in a grid operator's interconnection queue. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

Projects in the queue can also add a resource in certain circumstances without losing their place in the queue; for example, a solar project adding storage that does not materially change its interconnection application.

Hybrids' impact on grid flexibility and reliability may also depend on their participation in RTO and ISO capacity markets, which in turn could depend on how individual grid operators value them. According to the report, valuation methods are in transition across the country.

In 2023, CAISO valuation was based on a method combining effective load-carrying capacity (ELCC) and sum of parts. ELCC quantifies how much additional load a resource can support on the grid while maintaining reliability, while sum-of-parts valuation quantifies individual components of a hybrid and then combines them to determine an overall capacity value.

CAISO is planning for a 2025 transition to a "slice of day" method that will value plants according to their performance in every hour during the highest peak-load day of each month.

Similarly, the trend among other RTOs and ISOs is toward more targeted valuation methods. MISO has gone from a yearly valuation of a plant's output during the top eight peak demand hours to a seasonal framework in which capacity value is based on peak output in each season.

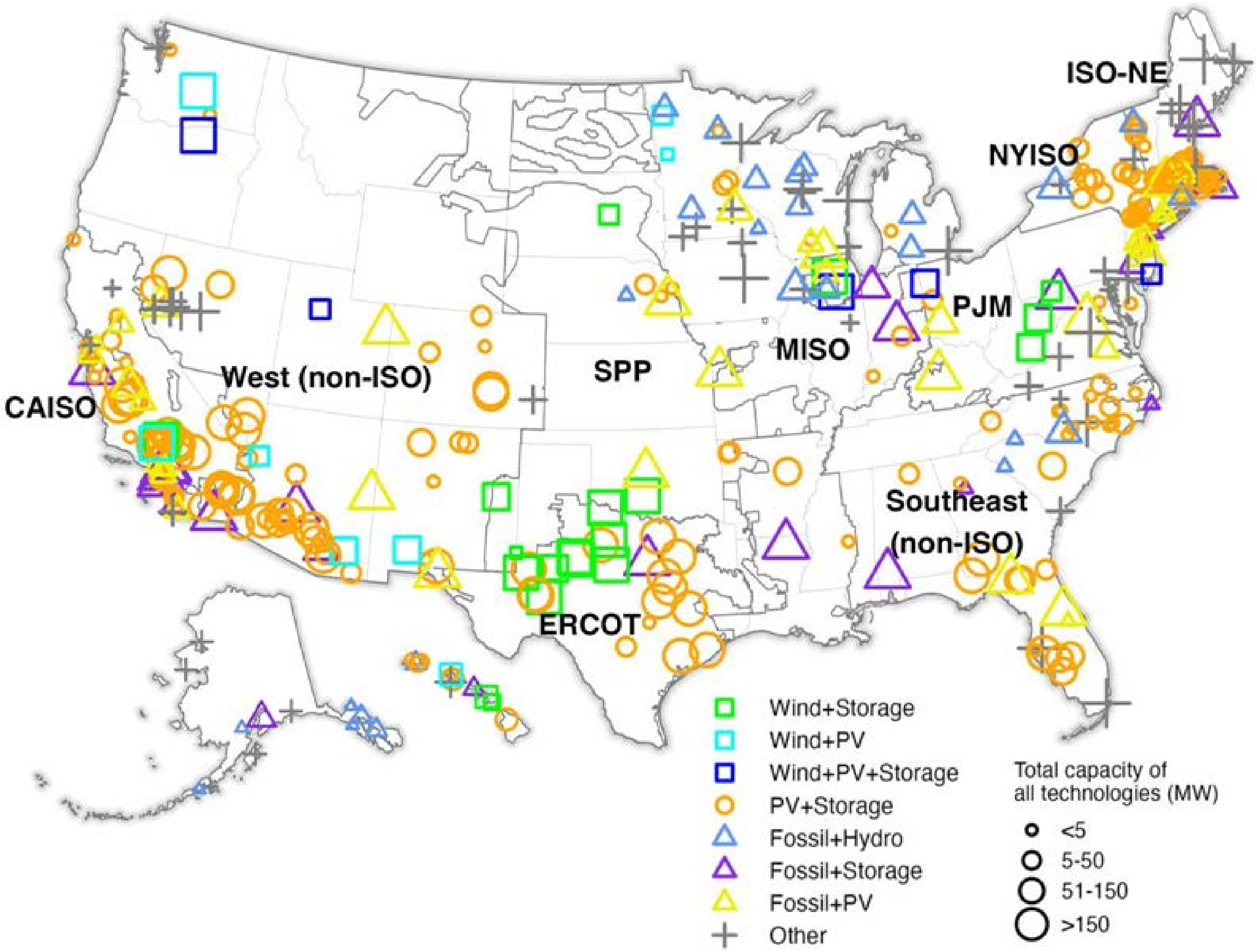
LBNL has research underway looking at which valuation methods might best reflect and optimize the different capabilities of hybrids and benefit the grid, Gorman said.

Whether Order 2023 will help get more solar-and-storage hybrids interconnected remains an open question. The rule is aimed, at least in part, at shortening queues by limiting the number of "speculative" projects seeking interconnection.

FERC/Federal News

Gorman recognizes that, like other projects, not all hybrids will make it through the queues. But, he said, "I think the 'speculative' term is charged. At LBNL, we try to maintain neutrality. If you talk to transmission providers, they will use 'speculative.' If you talk to the developers, they will tell you that the inherent uncertainty of the process requires them to discover how expensive it is to connect to the system, and since it takes so long to make it through the queues, they have to submit multiple requests."

Still, hybrids may have an edge. "There is an interconnection strategy to hybridizing," Gorman said. "Since these queues are so backlogged, instead of submitting two applications, FERC has now allowed that these hybridizing plants can go in as one … not skipping the queue *per se*, but sometimes avoiding some of the pain of the queue." ■



By the end of 2023, 469 hybrid power plants were online across the U.S. | *Lawrence Berkeley National Lab*

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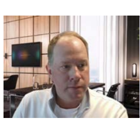
DOE Awards $3B to Tackle Gaps, Challenges in US Battery Supply Chain

FERC Proposes Further Cybersecurity Measures



New IBR Standard to Finally Go to Ballot

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CAISO/West News

Markets+ 'Equitable' Solution to Seams Issues, Backers Say

4th 'Issue Alert' from SPP Supporters Delves into Western Market Boundary Debate

By Henrik Nilsson

Proponents of SPP's Markets+ contend in their latest "issue alert" published Sept. 18 that the framework provides a much more equitable solution to tackling market seams than does CAISO's Extended Day-Ahead Market (EDAM).

In an email to *RTO Insider*, Jeff Spires, director of power at Powerex, said seams in the West have "resulted in inequitable outcomes, shifting value and reliability risk between subregions, and these outcomes are largely not captured in available studies to date." (See *SPP Briefs: Week of Nov. 7, 2022*.)

It's a point that Powerex — the first and, so far, only entity to tentatively commit to joining Markets+ — has broached before. In March, the Canada-based energy trader issued a report criticizing CAISO's operational practices in the Western Energy Imbalance Market (WEIM) during the January 2024 cold snap in the Northwest. The report argued that CAISO's processes unjustifiably limited energy transfers into the region during the weather event and squeezed wholesale electricity price spreads between the Northwest and Southwest through congestion charges at the ISO's border with Oregon, benefiting California parties at the expense of those in the Northwest. (See *Powerex Report Expands NW Cold Snap Debate*.)

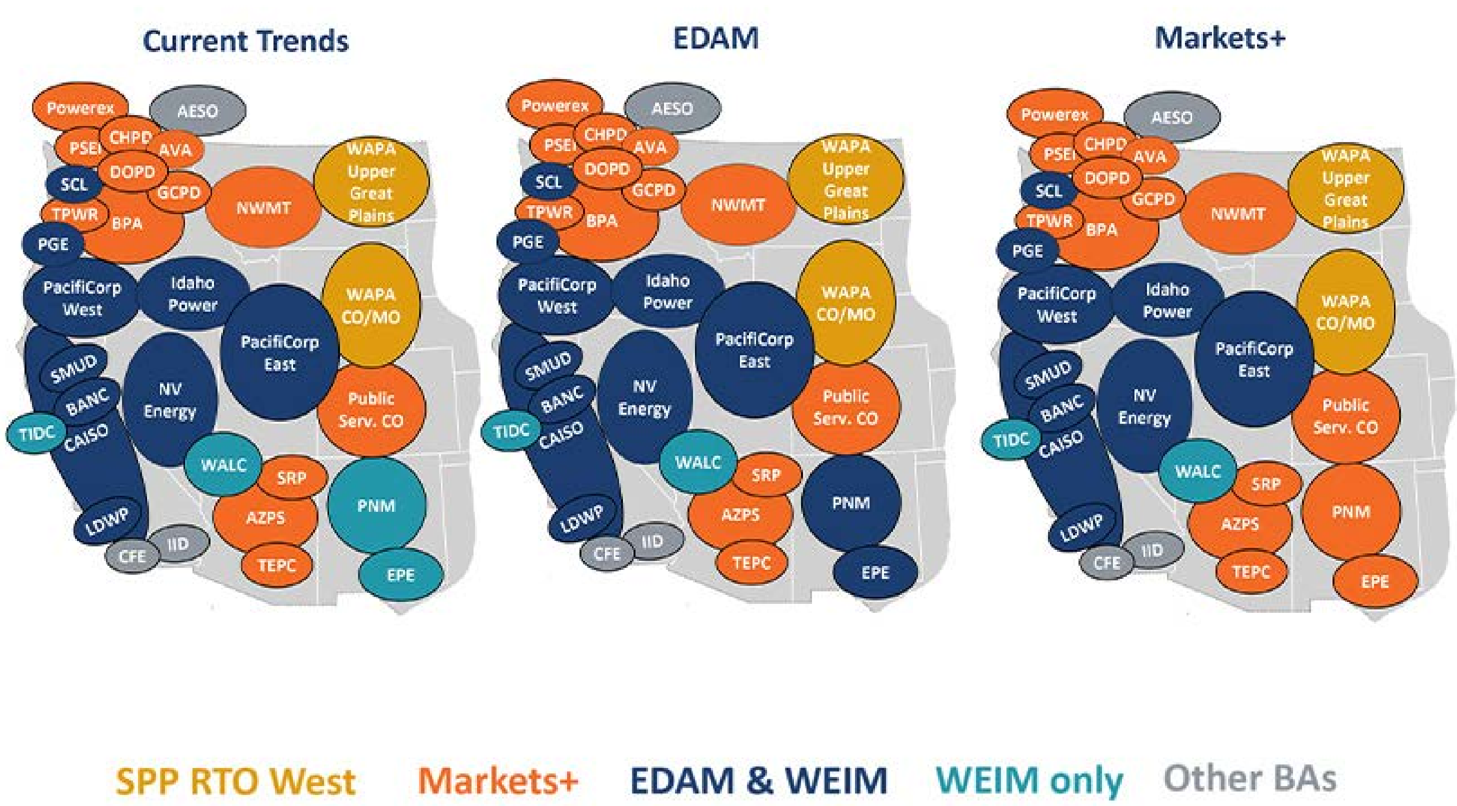
Reiterating the points in the issue alert, Spires added that Markets+ "creates the opportunity for more equitable outcomes by leveraging its independent governance, its impartial operator and SPP's demonstrated ability to negotiate seams agreements on a peer-to-peer basis with neighboring markets."

The alert is the fourth published in a series of seven notices intended to highlight Markets+'s purported advantages over CAISO's Extended Day-Ahead Market (EDAM) and WEIM. The *first* covered differences between how the two markets would be governed, the *second* focused on reliability, and the *third* compared pricing practices.

The contributing parties include Arizona Public Service, Chelan County Public Utility District (PUD), Grant County PUD, Powerex, Public Service Company of Colorado, Salt River Project, Snohomish PUD, Tacoma Power, Tri-State Generation and Transmission Association, and Tucson Electric Power.

In the recent alert, the backers argue that Markets+ is a neutral market operator and can, therefore, resolve seams issues between adjacent balancing authority areas and adjacent transmission service providers (TSPs) more equitably than CAISO's EDAM.

"For entities outside California, joining EDAM would mean accepting that their BA-to-BA and TSP-to-TSP seams will be resolved by market rules developed by the CAISO under its governance framework, and implemented by a market operator that is also one of the participating BAs and one of the participating



This map illustrates how seams between Western electricity markets could shape up based on current expectations for market choices among the region's balancing authorities. | *The Brattle Group*

TSPs," the alert said.

Additionally, allowing CAISO to set the market rules could lead to the California load receiving priority over other regions during heat waves, according to the alert. The parties also argued that CAISO's market rules have led to concerns over inequitable distribution of congestion value, a point emphasized in Powerex's March report.

Instead of relying exclusively on CAISO to resolve seams issues, the entrance of Markets+ will lead to each market operator attempting to ensure "that its participants receive the fair value of trade at each applicable seam, including through seams agreements negotiated between these peer market operators, as is the practice today between adjacent organized markets in the Eastern Interconnection," according to the alert.

Trade across seams is also enhanced under Markets+ because it removes trade barriers and uses a flow-based dispatch, which will "facilitate greater reliability and economic benefits relative to today by enabling more transfers across the same transmission infrastructure, including across BA-to-BA and TSP-to-TSP seams," according to the alert.

'Equitable and Efficient'

In response to the issue alert, CAISO spokesperson Anne Gonzales told *RTO Insider* that the ISO remains focused on "implementing EDAM in a manner that best meets the needs of the region's diverse interests."

"We continue to work with our partners to advance the Western energy markets, including the equitable and efficient management of seams with neighboring areas — whether in organized markets or not — and to grow its footprint to deliver maximum reliability, economic and environmental benefits to customers West-wide," Gonzales said.

In its own March report on the January cold snap, CAISO contested the negative characterization of how it managed flows across its seam with the Northwest during the deep freeze, contending that the event mostly demonstrated the value of the WEIM under stressed grid conditions, while the associated congestion charges reflected the functioning of mechanisms seen in any organized electricity market. (See *NW Freeze Response Shows WEIM Value, CAISO Report Says*.)

The prospect of seams has been an especially fraught issue in the competition between Markets+ and EDAM.

EDAM's key supporters, who champion the cause of a single electricity market in the West that pointedly includes California, have warned that a divided West will prevent the region from realizing the full "diversity benefit" of resources across its broad footprint and could increase future reliability risks.

On the other hand, Markets+ backers have played down any risks associated with seams. During a May workshop, Bonneville Power Administration officials noted the agency has deep experience dealing with market seams and made clear that seams concerns would not dictate its choice of a market. (See *Seams Concerns Won't Drive Day-ahead Market Decision, BPA Says*.)

For its part, SPP has said it is prepared to take a leadership role in managing Western seams based on its own experience developing seams policies with markets neighboring its RTO in the Eastern Interconnection — a point reprised in the Sept. 18 alert. (See *SPP's Experience with Seams Could Help Markets+*.) ■

Robert Mullin contributed to this article.

CAISO/West News

4 Utilities Nearly Compliant on Order 2023 Rule Changes

FERC Rulings Cover Idaho Power, Puget Sound Energy, Black Hills Colorado, Golden Spread

By Robert Mullin

FERC has largely approved Order 2023 compliance filings for four utilities in the West and Texas, directing them to submit further compliance filings within 60 days.

The utilities include Idaho Power (*ER24-10*), Puget Sound Energy (*ER24-1559*), Black Hills Colorado Electric (*ER24-2023*) and Golden Spread Electric Cooperative (*ER24-2027*).

FERC approved Order 2023 in July 2023 to revise its *pro forma* generator interconnection rules to speed up processes in backlogged interconnection queues throughout the U.S. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

The order changed the commission's *pro forma* interconnection rules to require transmission service providers to shift their approach to interconnection from a first-come, first-served serial process to a first-ready, first-served cluster process; increase the speed of queue processing; and incorporate technological advancements such as grid-enhancing technologies into the process.

FERC in March partly approved Idaho Power's initial Order 2023 filing, asking the utility to align its interconnect procedures with the order's requirements related to the cluster study process, the allocation of cluster network upgrade costs and site control. (See *FERC Upholds, Clarifies Generator Interconnection Rule*.)

The commission also had asked the utility "to either justify unexplained variations as consistent with or superior to the commission's pro forma procedures and agreements or adopt without modification the commission's pro forma procedures and agreements" and to remove proposed tariff revisions that exceeded the scope of the order.

In its Sept. 19 ruling, FERC approved revisions to Idaho Power's initial filing related to the cluster study process, allocation of upgrade study costs and site control, noting the utility largely adopted the commission's *pro forma* rules except for "minor variations." The commission made a similar finding on the utility's rules around site control and the transition to the "first-ready, first-served" cluster process and affected system study process.

Idaho Power was among the four utilities to win partial FERC approval for its Order 2023 compliance filing. | *Idaho Power*

FERC additionally said Idaho Power had satisfied the commission's request that it rescind previously proposed revisions to the utility's surplus interconnection service rules that were determined to be outside the scope of Order 2023 but directed the utility to delete a section of the tariff related to those rules within 60 days.

The commission issued similar rulings for the other three utilities, finding their proposed tariff revisions largely compliant with Order 2023 but requiring each to submit additional compliance filings within 60 days to account for minor shortcomings in their previous filings.

The sticking points for Puget Sound Energy's filing centered around "unexplained" deviations from the *pro forma* language in the utility's revisions related to its cluster network upgrade cost rules and affected system agreements.

In its order on the Black Hills Colorado filing, FERC approved the utility's deviations from *pro forma* rules related to operating assumptions for interconnection studies, specifically its practice of not determining the network upgrades required for a charging electric storage resource in its interconnection study process because, when charging, a storage resource "looks and acts more like load than an injecting generator." Black Hills said instead it would determine the impact of those resources through the transmission service request process.

The commission's partial approval of Golden Spread's filing included a rejection of the co-op's removal of *pro forma* language saying that, for transmission providers that employ fuel-based dispatch assumptions, "a request to add a generating facility of a different fuel type to an existing interconnection request would always constitute a modification that would require study." Golden Spread omitted that language, saying it doesn't use fuel-based dispatch assumptions, but the commission directed it to restore the language in an additional compliance filing. ■

CAISO/West News

WECC, Members Grapple with Strategic Vision

Discussion Spurs Debate over Organization's Motto

By Elaine Goodman

WECC has released a draft long-term strategy focused on reducing risks to reliability. | *© RTO Insider LLC*

A proposed update to WECC's long-term strategy has sparked a debate over whether the organization should describe itself as "*The* Voice of Reliability in the West."

The phrase figures prominently in a draft of the long-term strategy, which was discussed by WECC's Board of Directors on Sept. 17 and during its annual member meeting Sept. 18.

WECC decided to update the strategy in part because the Western Interconnection is changing "at a magnitude and pace that is unparallelled," the *draft document* said. The current version of the strategy was adopted in 2020. (See *WECC Board Approves New Chair, Long-term Strategy*.)

"Even in the last year, new things are coming into focus," General Counsel Jeff Droubay told the board. "Large loads, as an example, brought about by data centers, AI, crypto mining. We're seeing these loads come online in an unprecedented way."

The draft strategy lists five "impact areas" that are largely focused on reliability.

"Our holistic risk-based approach uses all the tools and skills available to deliver comprehensive risk mitigation strategies," the document states under Impact Area 1.

But during the member meeting, some members questioned the strategy's statement that WECC is "uniquely positioned to be *The* Voice of Reliability in the West."

Pat O'Connell, chair of the New Mexico Public Regulation Commission, said the term "the voice" was "a little too heavy-handed."

O'Connell noted that he's deeply involved in reliability in New Mexico in his work as a regulator. And groups participating in the Western Resource Adequacy Program (WRAP) are also playing a role in reliability, he said.

"There is no one of us in charge of the whole thing," O'Connell said.

Others at the meeting suggested alternative wording such as "a critical voice for reliability" or "a strong voice leading the pursuit of interconnection reliability."

WECC member Grace Anderson from the California Energy Commission said the strategy should further emphasize WECC's interconnection-wide work. She said reliability of the Western Interconnection is different from distribution reliability, for example.

During the board meeting, WECC board member Felicia Marcus said she likes that the strategy describes how WECC is viewed by others. For example, Impact Area 4 states that WECC's "resource- and technology-neutral, interconnection-wide perspective is respected and trusted to assure decision-makers that they have an independent partner to rely on."

But Anderson said the document left her unsure about WECC's plan of action.

"To me, I think about a strategic plan, and it's about what we're going to do, how we're going to prioritize," Anderson said.

Responding to Anderson, Droubay said the plan is intended to work "hand-in-glove" with scorecards that WECC uses to show whether initiatives are proceeding on schedule.

Another goal of WECC's long-term strategy update is to align with a new strategy being developed by the ERO Enterprise, which consists of NERC and six regional entities including WECC.

The plan's first area of focus is using "a broad range of data, tools and approaches" to address existing risks and prepare for emerging and unknown risks to the grid.

Other focus areas are maintaining cyber- and physical security programs; promoting stakeholder engagement; and performing as an "effective and efficient team."

During the Sept. 17 meeting, WECC's board voted to endorse the ERO Enterprise Long-term Strategy. NERC's board is expected to vote on the strategy in December.

As for its own long-term strategy, WECC will accept feedback on the draft document through October. A final version of the document is expected to go to the WECC board for approval in December. ■

CAISO/West News

July Sees New Western Peak Despite Moderate CAISO Demand

Interconnection Peak Load Nears 168,000 MW, While ISO Remains Well Below Record

By Ayla Burnett

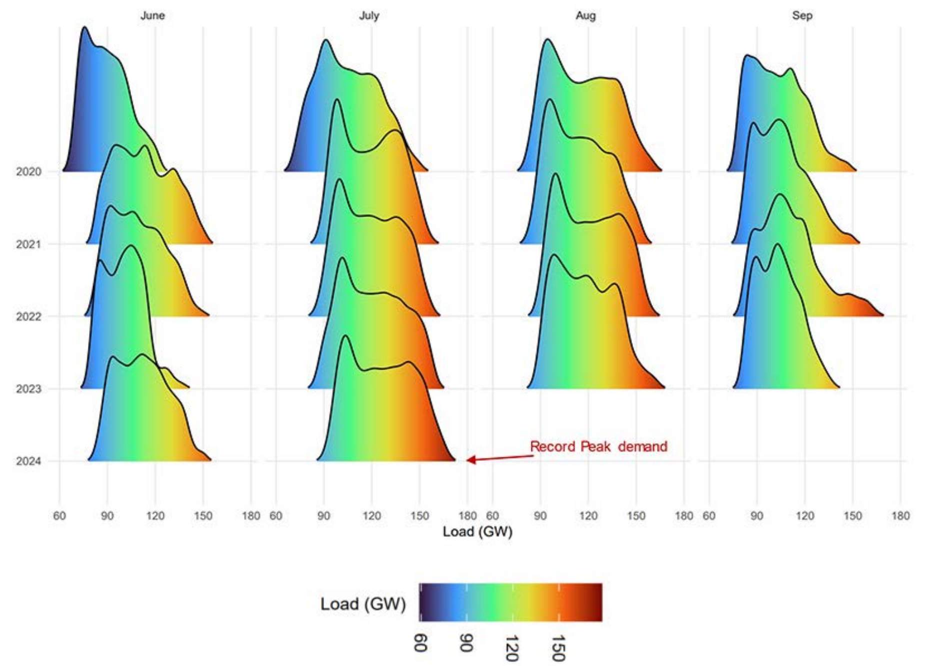
The Western Interconnection reached a record-breaking peak load July 10 despite relatively moderate demand in CAISO, the ISO said during a Sept. 18 meeting of its Market Performance and Planning Forum.

"When you look holistically across the West, it happens to be the warmest July on record, and that really drove the high loads in the Western Interconnection," Guillermo Bautista Alderete, director of market analysis and forecasting at CAISO, said.

The Western grid's peak reached 167,988 MW, slightly higher than the previous record in 2022. July saw many hours with high demand, Alderete said, and so the peak wasn't necessarily an outlier for the month.

Despite record-breaking conditions across the West, temperatures in the CAISO system where the demand was concentrated were "not that extreme," keeping ISO loads moderate, with a peak of about 45,000 MW — well below the historical peak of 52,000 MW.

"At the end of the day, it is not only how high the demand is, but also how well-equipped we are to handle that level of demand," Alderete said.



The Western Interconnection reached a new peak of 167,988 MW this past July. | *CAISO*

'Substantial Volumes of Exports'

Favorable resource adequacy conditions in CAISO helped support high loads in the West.

"We need to have enough resource adequacy capacity to be able to meet our actual load plus our reliability obligation. … When you put that obligation together and compare that against the resource adequacy capacity that we have available, you can see we were within a healthy margin," Alderete said. "We were never even really close to hitting the resource adequacy showing level, and that means that the levels of demand that we have in the system were moderate enough that the resource adequacy capacity was sufficient to meet that obligation."

CAISO experienced a marginal increase in RA capacity from 2023 to 2024, a trend the ISO expects will continue over time. Given the moderate levels of demand in the ISO's balancing authority area in July, and even on the most critical days of July 23-25, RA capacity was enough to meet the load obligation.

CAISO's prices increased as expected in July, reaching peaks on July 24. In June, average prices were typically below \$50/MWh, while in July, they rose to \$200/MWh for hours ending 7 and 8 p.m. Prices in the Pacific Northwest remained low compared with California and the Desert Southwest.

"Practically speaking, even those prices are moderate given all the conditions that we have when we look at the real-time," Alderete said.

Import and export levels were close to historical norms as well. Most imports with self-schedules or bids at or below \$0/MWh were cleared in both the day-ahead and real-time markets, though up to 640 MW of bid-in RA couldn't clear given path derates on the Malin intertie because of the impact of the Park Fire.

CAISO cleared "substantial volumes of exports" in July due to conditions driven by record loads across the Western Interconnection, resulting in several days of net exports.

While the ISO had to reduce exports on very few days, its hour-ahead scheduling process on July 24 reduced up to 900 MW of exports.

The Western Energy Imbalance Market (WEIM) provided operational benefits and offset risk for members by facilitating assistance energy transfers (AETs), which allow a participating BA to receive energy when it does not meet the market's resource sufficiency requirements ahead of a trading interval. Ten WEIM balancing areas opted into the AET program in July, the largest rate of participation since the program's inception, Alderete said.

The ISO in July also identified three issues related to the Residual Unit Commitment (RUC) process and incorrect reporting of exports.

"I would say, in the grand scheme of things, they are relatively minor items, but we want to provide the transparency," Alderete said.

On July 4, the RUC process triggered undersupply infeasibility — which indicates a potential supply shortage — without attempting to reduce low-priority exports to maintain supply, but the issue was fixed the following day.

The month also saw an incorrect reporting of export reductions in the customer portal that was fixed July 9, as well as an incorrect loss of high-priority status for certain exports. In particular, under different permutations of bidding in day-ahead and real-time markets, different bid validation rules triggered the unintended loss.

CAISO is assessing whether to revise the validation rules and has resolved all other issues, Alderete said. ■

CAISO/West News

New Western Tx Could Bring Big CO2 Benefits, Study Shows

PNNL Report Sees 73% Reduction from Projects Already in Pipeline

By Henrik Nilsson

| © RTO Insider LLC

Carbon dioxide emissions from the Western U.S. power sector could drop by 73% from 2005 levels if 12 transmission projects in the development pipeline are finished by 2030, according to a new *study* from the U.S. Department of Energy.

The report's model incorporates 12 future transmission projects, which collectively span about 3,000 miles, and the likely wind and solar power projects and battery storage systems that would take advantage of the new capacity. The scenario "shows a reduction of CO2 emissions by 73% relative to 2005, reaching to 27% CO2 emissions in 2030," according to the report published by the DOE's Pacific Northwest National Laboratory on Sept. 13.

"This work is important because it shows that significant progress can be made [toward] decarbonization policy objectives if we proceed with already-planned transmission projects to meet new capacity needs with new renewable resources," Nader Samaan, report co-author and chief power systems research engineer at PNNL, told *RTO Insider* in an email.

The report said more transmission could lead to renewable energy replacing some large thermal fossil generation, with the highest emissions reductions occurring in Utah, Nevada, Wyoming, Colorado, Arizona and New Mexico.

"As of July 2024, the Western Interconnection hosts 30 gigawatts of wind power, 38 GW of solar power and 14 GW of energy storage," the study said. "The report's scenario would add an additional 35 GW of wind, 31 GW of solar and 12 GW of energy storage by 2030."

The 12 transmission projects behind the model include the 500-kV Boardman-to-Hemingway line, the Gateway West project and the Southwest Intertie Project-North, among others. (See *DOE Awards $371M to Regulators, Communities Grappling with New Tx*.)

Aside from the purported environmental advantages, the transmission projects could also decrease generation costs by 32% compared with a reference case in which the projects were not built. However, "capital costs for generation and transmission are not considered as part of this analysis and would be needed for a complete economic evaluation," according to the report.

"Most of the infrastructure upgrades selected are either in interconnection queues or the transmission planning pipeline, increasing the likelihood that they will be realized," the report stated. "In other words, the projects selected in this analysis rely implicitly on some economic analysis conducted by those proposing the projects."

The model also predicts a 26% reduction in California's annual net energy imports from the Northwest. Under the scenario, the state could tap into "newly integrated wind resources from areas with abundant wind, such as Wyoming and New Mexico," according to the report. This would also provide congestion relief for the Northwest, the report added.

The report is part of the DOE-funded National Transmission Planning Study, slated to come out this year.

"The upcoming National Transmission Planning study will expand on the possible transmission buildouts that could help the nation reach higher decarbonization goals," Samaan said. ■

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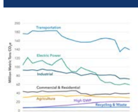

California GHG Emissions Decreased 2.4% in 2022

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CAISO/West News

Comments on Western RO Stakeholder Plan Show Complexity of Effort

Pathways Receives 22 Responses to Draft Stakeholder Process Proposal

By Robert Mullin

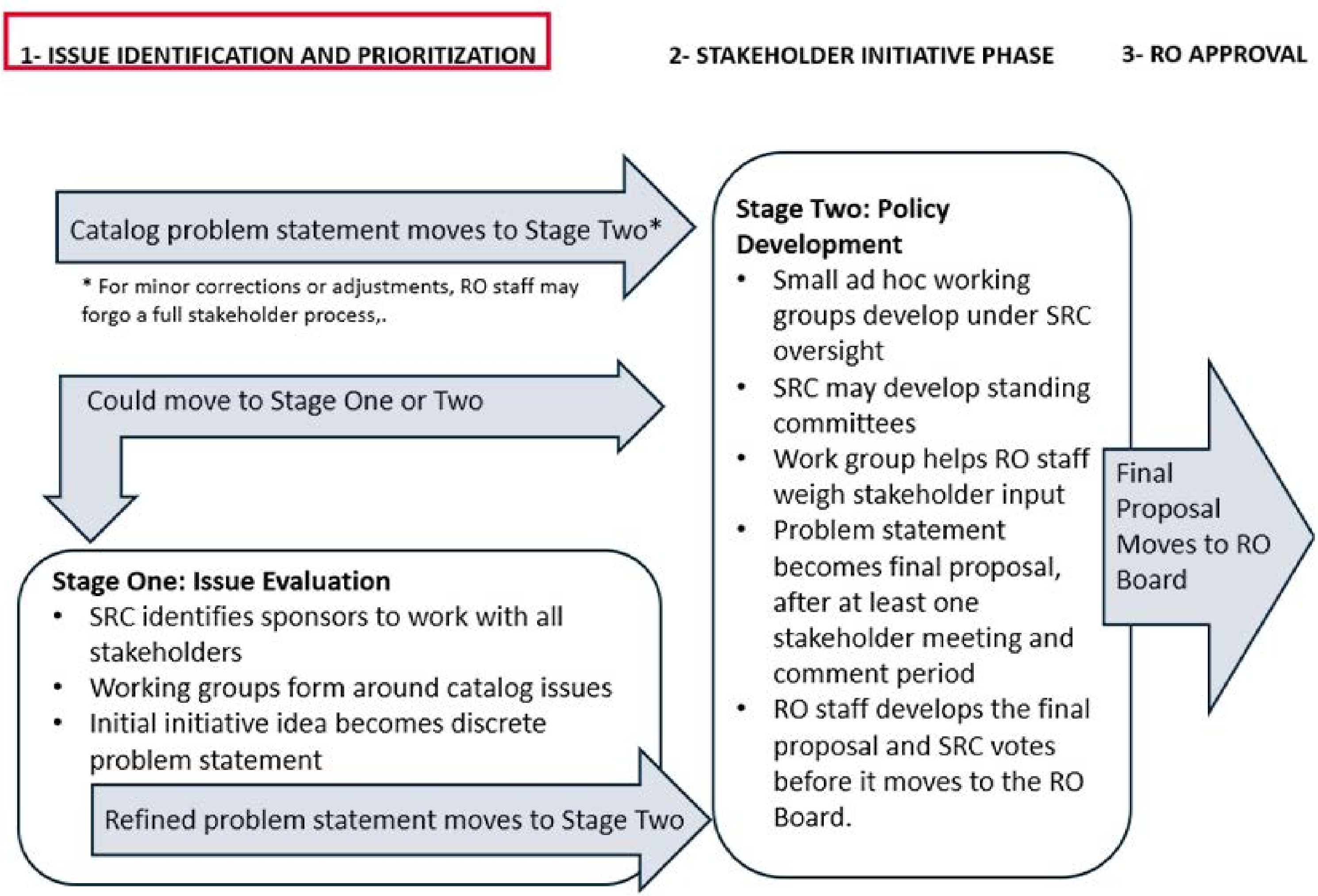
Recent stakeholder comments filed with the West-Wide Governance Pathways Initiative illustrate — once again — the complexity of building the new kind of Western "regional organization" (RO) envisioned by backers of the effort.

The comments came in response to Pathways' *draft plan* for the RO's stakeholder process, an aspect of the organization likely to be as important as its governance structure in swaying some Western electricity sector participants to choose CAISO's Extended Day-Ahead Market (EDAM) over SPP's Markets+.

The Pathways Launch Committee floated the plan during an Aug. 28 workshop, the last of four such intensive workshops facilitated by consulting firm Gridworks to hash out ideas about how the RO would engage with its stakeholders and how the stakeholder process would tie into governance. (See *No Clear Blueprint for Western 'RO' Stakeholder Process*.)

At the heart of the proposal is the formation of a Stakeholder Representatives Committee (SRC), described as the "primary stakeholder body that works with RO staff to catalog and prioritize initiatives, as well as to define initiative problem statements and solutions."

During an Aug. 28 workshop to discuss the RO's stakeholder process, Launch Committee Co-Chair Pam Sporborg, director of transmission and market services at Portland General Electric, described the SRC as an evolution of the Western Energy Imbalance Market's (WEIM) Regional Issues Forum, which itself has evolved over time into a key stakeholder body for addressing issues related to that market.



Flow chart illustrating the proposed stakeholder process for the regional organization envisioned by the Pathways Initiative. | *West-Wide Governance Pathways Initiative*

CAISO/West News

The proposal calls for the SRC to be a sector-based body, with sectors to be "self-organized" and committee representatives selected by members of each sector.

"Sectors may elect to use selection criteria to establish diversity among SRC representatives that may be important to the sector," a *presentation* accompanying the proposal states.

The proposal defines nine sectors to be represented on the SRC, including:

- EDAM entities (one seat);
- WEIM entities (two seats);
- CAISO participating transmission owners (2);
- transmission-dependent utilities (3), including one seat reserved for community choice aggregators;
- public interest organizations (PIOs) (1);
- consumer advocates (1);
- large commercial and industrial consumers (1);
- independent power producers, independent transmission developers and marketers (3), with assurance that IPPs and marketers each have an opportunity for a seat to represent different business models; and
- distributed energy resources (1).

One seat would be reserved for federal power marketing administrations (PMAs) in either the EDAM or WEIM sectors — if any such agency participates in those markets.

According to the proposal, every organization registered to vote in the RO would have the chance to specify their support, opposition or neutrality when the SRC votes on an issue. To be eligible to vote, an organization must register in a specific sector and agree to a code of conduct.

"Once the organizational votes are tallied, the nine sectors of the SRC will also vote, with the threshold for support, opposition or neutrality determined by the organizations in the sector," the proposal says. "The SRC representative will report on any specific splits that have been established by that sector, consistent with the self-organizing principle described above. The results of all votes will be provided in the materials related to the issue."

The plan also puts stakeholder initiatives into three categories, including:

- compliance/nondiscretionary, such as responses to FERC rulemakings or fixes to market design flaws that require tariff changes;
- compliance with state and local public policy, which could require stakeholder discussion to determine whether a tariff change is needed; and
- discretionary initiatives that can be advanced by any stakeholder, the states committee, market monitor, "independent market adviser" or RO staff.

Once initiatives are categorized, the stakeholder process would entail prioritizing them through a "road map" process. That would be followed by an "issue evaluation" to determine the nature of the problem to be solved (stage 1) and an "identification of solutions" (stage 2). The last step would be seeking approval by the RO board.

Dilution Concern

The Pathways Launch Committee received 22 comments on the proposal, including one combining responses from seven PIOs.

Other commenters included utilities (some jointly filing), large energy consumers, industry interest groups, an energy trader, the Bonneville Power Administration and Google.

In its *comments*, Black Hills Power expressed concern that the SRC "does not provide sufficient representation to utilities, which play a critical role in ensuring grid reliability and managing market operations."

The South Dakota-based utility is one of two Black Hills Energy subsidiaries that last month said it would pull out of SPP's Western Energy Imbalance Service and join CAISO's Western Energy Imbalance Market, although it made no commitment to EDAM. (See *CAISO's WEIM Plucks Black Hills Utilities from SPP's WEIS*.)

"We recognize that all registered utilities within a sector, including utilities, can vote and contribute to the sector's overall vote," Black Hills wrote. "However, we still have concerns that utilities' votes will be diluted within sectors where there are diverse participants."

Black Hills recommended that Pathways ensure that utilities have "a formal mechanism for ensuring that their interests are not overshadowed by other entities within the sector." It proposed a "more tailored sector designation for utilities" with "clear distinctions" among the types of utilities — such as investor-owned or publicly run — "to ensure that their unique perspectives are not lost within larger, more diverse sectors."

NV Energy, which has already committed to joining the EDAM, *said* it supported the use of a sector-based process only for selection of the RO board and development of the annual roadmap to prioritize RO initiatives.

"While recognizing potential benefits of indicative votes, NV Energy does not believe the sector-based process proposed in the draft discussion paper is the best approach," the utility wrote.

Instead, NV Energy "strongly supports" the indicative voting approach CAISO used in the recent stakeholder process for Pathways Step 1 — which granted the Western Energy Markets (WEM) Governing Body "primary" authority over matters related to the WEIM and EDAM. (See *CAISO, WEM Boards Approve Pathways 'Step 1' Plan*.)

In that situation, the utility noted, the ISO "simply added a voting request to the stakeholder comment template asking if the participant supports, opposes or was neutral to the proposal. The votes were then tabulated and presented to the WEM Governing Body and the CAISO Board of Governors to assist in their deliberations."

NV Energy said that approach "provides far greater transparency" because it:

- records and presents each specific vote, preventing intra-sector disagreements over an initiative from being concealed by the sector's majority vote;
- "better represents minority interests and reduces a feeling of disenfranchisement" among entities holding a minority position within a sector; and
- "reduces the burdensome and time-consuming process for separate sector-led votes."

The utility also recommended a second seat for EDAM entities and questioned the need for three seats for transmission-dependent utilities.

"Presumably, these are transmission-dependent utilities within the EIM/EDAM footprint," the utility wrote. "If one seat is for a transmission-dependent utility within California and one for a transmission-dependent utility outside of California, it may be understandable but does seem to create a mismatch with the three seats being allotted to the total of EIM and EDAM entities."

'Ambiguities' or 'Right Balance'

Salt River Project (SRP) said it "generally sup-

CAISO/West News

ports" creation of a "parent committee," such as the SRC, "through which issues flow both up to the regional organization board and down to working groups."

"This structure ensures that topics are defined at a high level based on stakeholder input before being remanded down to the working groups/task forces," it wrote.

But SRP also recommended changing the proposed composition of the SRC to match that of the Western Resource Adequacy Program's Nominating Committee, which consists of representatives from investor-owned utilities (2), consumer-owned utilities (2), retail competition load-responsible entities (1), PMAs (1), independent power producers/marketers (1), PIOs (1), retail customer advocacy groups (1), industrial customer advocacy groups (1) and one "independent sector" representative for entities that don't fit into any other category.

SRP also agreed with the proposal that RO staff should take on most of the "burden" of facilitating and administering the stakeholder process, saying the arrangement would allow stakeholders to participate "nimbly" regardless of their staffing levels.

Google offered no comment on the list of proposed SRC sectors but recommended that each sector develop a manual of board-approved bylaws to define who could be a member of the sector, frequency of meetings, how it develops consensus and how it communicates its positions to the RO's committees, staff and board.

"This structure would mirror MISO's, where sectors are self-organizing but each sector's bylaws are approved by the board," the company wrote.

BPA requested that one additional seat be reserved for PMAs in either the WEIM or EDAM sector, assuming a PMA is a member of either. In the case of no PMA participation in either market, the agency asked that an additional seat be reserved for PMAs in the transmission-dependent utilities sector given that their transmission would still be used to deliver to load in the CAISO-run markets.

BPA said it supports the concept of a category for state and local public policy stakeholder initiatives, but it also wants federal obligations that may be statutory requirements for itself and the Western Area Power Administration to be added to the category.

"In implementing the process, it will be important to ensure that these initiatives only skip Stage 1 in situations where the problem statement has broad agreement or is so clearly defined by the state policy initiative that there is no room for discussion," BPA wrote.

The California Large Energy Consumers Association (CLECA) *commented* on "the imbalance between buyers and sellers in SRC voting sector definitions and encourages efforts to establish commensurate supply and demand representation." CLECA called for the Launch Committee to address the "imbalance" by providing each sector with two seats or, alternatively, just one seat or one seat with one backup.

"All sectors have heterogeneous membership worthy of adequate representation at the SRC. This revision partially restores the balance between supply and demand representation," CLECA wrote.

The Portland-based Public Power Council (PPC), which represents consumer-owned utilities in the Northwest, *raised* concerns about "the ambiguities in the RO/CAISO relationship based on the current proposal," saying the role of both the ISO staff and board is unclear.

"Also, it is unclear whether pursuing an RO stakeholder process as outlined in the discussion document would have any impacts on the existing CAISO stakeholder process and whether those processes would be kept distinctly separate, or whether there would be some combined discussions or efforts between the RO and CAISO. We would appreciate the Launch Committee addressing these issues in the Step 2 proposal," the PPC wrote.

The seven PIOs — which include the Northwest Energy Coalition, Western Resource Advocates, Natural Resources Defense Council and Environmental Defense Fund, among others — *said* the SRC "strikes the right balance between clear roles for each sector representative while allowing all interested stakeholders to participate in the process."

The PIOs expressed support for the lack of fees or other monetary requirements for participating in the RO's stakeholder process.

"This is an important aspect to ensure equal access for all stakeholders; if the regional organization were to require a fee for participating in the stakeholder process, that fee can be a barrier to smaller organizations that, because of competing priorities, may be unable to spend scarce resources on participation fees, and thus will be unable to have a full and equal voice, via voting or committee membership, in the process," they wrote.

Full comments on the Pathways stakeholder process proposal can be found *here*. ■

WestTEC Seeks to Close $2.1M Funding Gap Despite DOE Boost

Cost Estimate for Western Power Pool Project Has Jumped 27% This Year

By Elaine Goodman

The Western Transmission Expansion Coalition's (WestTEC) transmission planning study is getting a boost from a $1.75 million Department of Energy grant even as the cost of the project has grown to $6.1 million.

When the grant application was submitted in January, the preliminary project cost was $4.8 million. DOE is funding 37% of that, or $1.75 million. Western Power Pool (WPP), which is facilitating WestTEC, is expected to provide about $3 million in matching funds.

Additional funding of $2.2 million is coming from WECC, which is partnering with WPP on the project.

With the new cost estimate of $6.1 million, WPP is working to close a funding gap of about $2.1 million. Funds will come from sources including WPP members, WestTEC participants and other regional partners that support WestTEC, WPP CEO Sarah Edmonds said in an email.

During the WECC Board of Directors meeting Sept. 17, CEO Melanie Frye said a three-party contract for the WestTEC project has been drafted among WPP, WECC and Energy Strategies, an energy consulting firm that will do most of the analytical work.

Frye said WECC is making sure the project qualifies as reliability work under Section 215 of the Energy Policy Act.

"As of yet, we've not expended any funds," Frye said. "We are wanting to make sure that we have the contract in place and that we're very clear on what it's funding so that it's not falling outside the bounds of the Section 215."

The WestTEC study will address long-term interregional transmission needs across the Western Interconnection. The WestTEC Steering Committee recently unanimously approved the project's *study plan*. (See *WestTEC Committee OKs Plan for 'Actionable' Tx Study*.)

The study is expected to take place over the next two years. The goal is to produce transmission portfolios for 10- and 20-year planning horizons. In addition to enhancing Western reliability, the portfolios will also factor in economic efficiencies and state policy goals.

The grant funding for the study is from the Wholesale Electricity Market Studies and Engagement Program in the DOE's Grid Deployment Office. The program provides funding to states and regions related to developing, expanding or improving wholesale electricity markets.

When U.S. wholesale markets were designed three decades ago, the nation's electric grid "looked much different," GDO Director Maria Robinson said in a statement regarding the grant program.

"With the widespread deployment of new clean energy resources and advanced grid and transmission technologies, creating effective wholesale electricity markets is critical," Robinson said. ■

Funding pieces are falling into place for the $6.1 million WestTEC transmission planning project. | *PacifiCorp*

CAISO/West News

CAISO, Stakeholders Consider GHG Attribution for Non-priced States

PGE Offers Suggestion for WPTF's EDAM Proposal

By Ayla Burnett

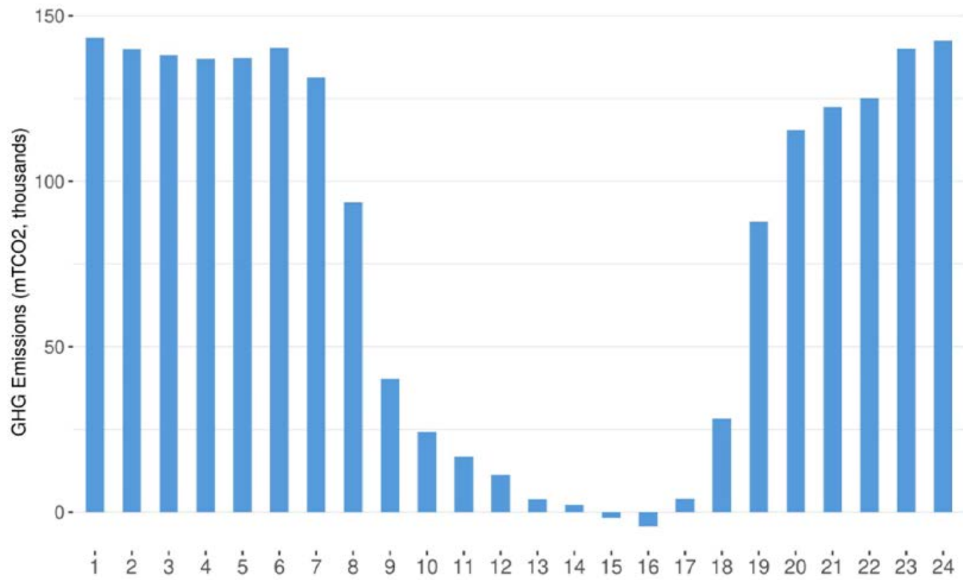
CAISO is recommending that it implement a Western Power Trading Forum (WPTF) proposal that could help the Extended Day-Ahead Market track and account for greenhouse gas emissions in a way that considers the variety of carbon pricing programs across the West.

Central to the proposal, first presented by WPTF in March, is use of residual market supply — energy not committed to market participants or attributed to GHG regulation areas.

The proposal assumes that if the market can ensure entities are able to claim and procure their own resources to meet load, what is left is a relatively small increment of energy, which is the residual supply, Clare Breidenich, WPTF assistant executive director, explained at a March meeting of the ISO's Greenhouse Gas Coordination Working Group.

The residual supply helps determine a residual emissions rate, which represents a dispatch-weighted average emission rate of the market supply. Under this framework, leftover energy in the market would go into the residual supply. (See *CAISO, Stakeholders Consider 2 GHG Mechanisms for EDAM*.)

"This conversation around a residual rate is going to be robust in terms of how we calculate that," Anja Gilbert, a lead policy developer at CAISO, said in a Sept. 19 meeting of the GHG group. "There's questions on how we think about a residual rate for price-based states, for states with climate policies not based on a price, and then for states that do not have climate policies."



Graph of GHG emissions serving ISO load in April 2024. | *CAISO*

Portland General Electric Weighs in

Pam Sporborg, director of transmission and market services at Portland General Electric (PGE), weighed in on how states like Oregon that don't price carbon but do have climate policies could incorporate the proposal.

While Oregon doesn't put a price on GHGs, the state requires utilities such as PGE to reduce emissions every year until the utility is "under the 2030 hard cap for emissions that is based on an 80% reduction from a reference level."

"While that doesn't necessarily entail a price on those emissions, we do see it as a hard limit, which can indicate that we have a significant willingness to pay for those emissions," Sporborg said. "While we really like the structure and framework in this proposal, we want to open up some questions around how we can also ensure that capped states are having an equitable allocation or equitable access to the excess emissions framework consistent with or alongside of the GHG pricing zone states."

Connie Horng, PGE's principal greenhouse gas policy analyst, presented an alteration to the proposal, suggesting that if an LSE inside the GHG pricing area has excess designated energy, those megawatt hours and associated GHGs would be assigned to another LSE inside the pricing zone before being allocated to the residual market supply. Within this framework, PGE proposed looking beyond just a GHG pricing zone adjustment and incorporating a methodology that would be able to reflect all GHG regulated zones — including non-priced ones.

"How do we expand from just the pricing zones that impact Washington and California to include the regulation that applies to Oregon and potentially other states who have these strong caps and a compliance framework associated with GHG?" Horng said. "Our goal here is to allow all of the GHG-regulated states with the clean energy portfolio requirements that we are bringing to the market to solve for each other's excesses and shortfalls first, before we get that residual market calculation."

Gilbert questioned how the ISO might modify the approach to account for PGE's suggestion.

"Are we looking to modify the WPTF approach for price-based regions to include states like Oregon? Or is a separate residual rate for Oregon that is applied to Oregon LSEs or BAAs required?"

Sporborg said PGE was open to both solutions, but thinks they need to be explored more thoroughly.

"Our goal is to really maximize the diversity benefits from the states," Sporborg said. "Even though we don't have the pricing component to our regulation, we will still be making investments in a diverse portfolio of clean energy supply to meet our 2030 goal. … If we can find an opportunity that allows us to participate in the broadest regional diversity and to also benefit from the greening of the portfolios that will create this residual excess, I think that is the solution that we would want to get to optimally."

The ISO is seeing feedback on PGEs proposal in written comments and will continue to discuss it in later working groups. ■

ERCOT Technical Advisory Committee Briefs

Members Endorse Ancillary Services Methodology for 2025

ERCOT stakeholders have endorsed changes to the grid operator's *ancillary services methodology* as part of the annual process to determine the minimum amount of *products* that will be procured in 2025.

Staff's proposed modifications, presented to the Technical Advisory Committee during its regular monthly meeting Sept. 19, include three revisions to ERCOT contingency reserve service (ECRS). ERCOT *introduced ECRS last year*, but it drew opposition from the Independent Market Monitor, which said the service produced "massive" inefficient market costs totaling more than $12 billion in 2023. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

The Monitor is currently working with ERCOT and Texas Public Utility Commission staffs on a report for the Texas Legislature that is due by October. The IMM's director, Jeff McDonald, said there were "limited opportunities" to add lessons learned from the study to the AS methodology process but that he was happy with staff's recommendations.

"I think we've learned some things about procurement targets and some potential recommendations for how the procurement process can be adjusted to result in a lower cost without compromising reliability," McDonald told TAC. "We do note that that we're seeing a more targeted procurement through this process, resulting in a reduction in both the ECRS and [non-spinning reserve service] levels procured. We're happy to see that. ... We will have some recommendations that come out of the AS study that we feel will be very important to be taken up and discussed in the 2026 methodology process."

Staff proposals for ECRS include removing the adjustment for risk coverage during sunset hours to at least the 90th percentile; adjusting the frequency recovery portion to cover 70% of historic net load and inertia conditions; and computing the minimum ECRS requirements as the larger of the capacity needed to recover frequency and capacity needed to support net load forecast.

Since ECRS was first deployed in June 2023, staff said there have been "very few situations" when ECRS had to be released for both net load forecast issues and frequency recovery needs. The changes will result in setting ECRS quantities based on needs of the dominant operational risk in every hour, they said.

Luminant's Ned Bonskowski (right) shares his thoughts on ERCOT's stakeholder process with ERCOT General Counsel Chad Seely. | *ERCOT*

Staff also proposed minor changes to non-spin, regulation service and responsive reserve service (RRS):

- Non-spin will be revised so that the methodology computing its quantities between 10 p.m. and 6 a.m. uses a four-hour-ahead net load forecast error.
- Regulation quantities would be computed using the historic error in security-constrained economic dispatch's forecasted net load.
- The minimum RRS-primary frequency response (PFR) limit will change to 1,365 MW.

NRG Energy's Bill Barnes, who represents Reliant Energy Retail Services, asked whether the transition to real-time co-optimization (RTC) next year will affect the math used to calculate "some amount" of AS to be procured throughout the year. ERCOT has set a December 2025 go-live date for RTC, which will procure energy and AS every five minutes. (See *ERCOT Sets Go-live Date for RTC, ESR Project*.)

"We implement RTC and that all goes away, right?" he asked. "Because how much ancillary services you actually procure is all dependent on price. At that point, the quantities will vary significantly. So I'm wondering, how do we bridge that gap, right?"

"From our perspective, RTC does not change the quantity of ancillary services that we need because the quantities are based on the fundamental operational risks," said Jeff Billo, ERCOT's director of operations planning. "So it's how much RRS do you need to arrest the frequency? How much ECRS do you need to recover frequency? But those fundamentally are physics-based questions that RTC is not changing."

Billo said ERCOT will propose a methodology similar to the current one as the grid operator goes into 2026. He said he took note of stakeholder feedback from a recent AS workshop about procuring the services closer to real time or the operating day, as opposed to calculating it annually.

"I think that could change the quantities, but we think that doing that at the same time as RTC may not be preferable, and so we want to kind of put that off to 2027," he said.

The measure cleared TAC, 26-1, with a couple of abstentions. Calpine's Bryan Sams cast the

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lone dissenting vote against the changes, saying his organization believes there's additional risk with the reduction of regulation in the morning and during the winter.

"The second reason is we still believe that ECRS sends, or has sent, an investment signal for new generation development and the reductions in ECRS, I think, are harming that signal," Sams said.

ERCOT's protocols require staff to provide at least annually the methodology for determining the procured quantity of each AS needed for reliability. The grid operator's Board of Directors and the Texas PUC will both review the recommendations before making their decisions.

Members Discuss Stakeholder Process

TAC devoted the first two hours of the meeting to a discussion with staff of the stakeholder process and communications. Two hours and 25 minutes later, the membership agreed to reserve time at the next meeting to pick up the conversation.

Members discussed how decisions are made at TAC, how the decision-making process is presented to the board and how the reasoning behind opposing votes is shared with the board.

The discussion was prompted after the PUC's chair, Thomas Gleeson, said that the interaction between the board and TAC "did not work" for him during a July open meeting. (See *Texas Commission Rejects ECRS Rule Change*.)

The PUC's Barksdale English, a TAC member when he was with Austin Energy, said commission staff is working on a rulemaking related to the appeal of board decisions to the PUC and "should be coming soon."

"We talked a lot about what your role is here and how Barksdale English would love for TAC members to view your responsibility here," English said. "I guess it almost seems like there's another conversation that needs to be had around how do you codify TAC's role in receiving recommendations from your subcommittees and how do you codify what you're communicating up to the board. At the end of the day, it will be the board members' decisions on how to receive those requests."

'Cookies and Laughter'

After committee Chair Caitlin Smith, of Jupiter Power, said during TAC's August meeting that she was open to lightening the atmosphere for members following comments that "unlike SPP, we don't have 'cookies and laughter,'" stakeholders were greeted with a virtual cornucopia of tasty treats. (See "Lightening the Mood," *ERCOT Technical Advisory Committee Briefs: Aug. 28, 2024*.)

A large chocolate chip cookie that seemed to have been sent from SPP's Markets and Operations Policy Committee included a greeting that read, "SPP Cookie Power: From our stakeholder group to yours, we heard y'all need some cookies." Another container of cookies were iced with "SPP."

"I had an oatmeal raisin. It was delicious," one member said.

Two other boxes of cookies were decorated with images of ERCOT CEO Pablo Vegas, a laughing emoji and the words "TAC IS FUN."

The levity was provided by CIM View Consulting's Steve Reedy, who reminded TAC that it was "Talk Like a Pirate Day."

"How many letters does the pirate alphabet have?" he asked, before providing the answer. "I, I, R and the seven Cs."

Change to CLRs Dispatch

TAC unanimously endorsed a Nodal Protocol revision request and its accompanying Other Binding Document request (*NPRR1188*, *OBDR046*) after late comments were filed.

The protocol change would modify the dispatch and pricing of controllable load resources (CLRs) in response to the PUC's directive to increase the "utilization of load resources for grid reliability." It revises the market-participation model of CLRs that are not aggregate load resources so that they are dispatched at a nodal shift factor and settled for their energy consumption at a nodal price.

The committee also endorsed a combo ballot that included three NPRRs, one revision to the Nodal Operating Guide (NOGRR) and the annual under-frequency load shedding survey of transmission owners, which found they met requirements for all five thresholds.

The protocol and guide changes, if approved by the ERCOT board, will:

- *NPRR1215*: clarify that the day-ahead market's energy-only offer credit exposure calculation zeros out negative values, with any zeroed-out values being included in the calculation of the dpth percentile difference.
- *NPRR1237*: document the scenarios in which market participants are required to successfully complete retail qualification testing, regardless of whether the market participant previously received a qualification letter from ERCOT from prior retail flight testing.
- *NPRR1244*: align eligibility provisions for CLRs not providing PFR to provide ECRS. It would also include in physical responsive capability's calculation only the capacity of CLRs when they are qualified to provide regulation service and/or RRS that requires the CLR to be capable of providing PFR.
- *NOGRR263*: clarify that a CLR is only required to provide PFR when it is providing an AS that requires that resource to be able to provide PFR. ■

— Tom Kleckner

ISO-NE Planning Advisory Committee Briefs

Dave Burnham of Eversource Energy, representing the New England transmission owners (NETOs), discussed updates to the guidelines for asset condition project presentations at the ISO-NE Planning Advisory Committee on Sept. 18.

The New England states have been pressuring the TOs for greater oversight and transparency into the asset condition project planning process as the costs associated with maintaining the region's transmission infrastructure have ballooned in recent years. (See *New England States Raise Alarm on Eversource Asset Condition Project*.)

The states argue the review process at the PAC is insufficient, as the PAC lacks any authority to approve expenditures, which is under FERC's jurisdiction. The states have discussed the possibility of establishing an independent transmission monitor to oversee transmission spending in the region.

In response to the states' concerns, the NETOs have proposed and implemented changes to standardize presentations to the PAC, increase transparency into overall asset condition spending and solicit stakeholder feedback on their plans.

| © RTO Insider LLC

Burnham presented updates to the new asset condition process guidelines regarding PAC presentations and the standardization of asset grading.

Going forward, he said project presentations will "discuss any overlap between the proposed project and needs identified in recent ISO-NE studies."

"This change responds to several stakeholders' requests for information on correlation of asset condition needs with regional planning study efforts," Burnham said.

He also discussed an update to the NETOs' asset condition project database, which was published at the end of August.

The *database* includes cost estimates on planned, proposed and under-construction projects, as well as preliminary information on under-development projects. Projects expected to come in-service this year are projected to cost $903 million, while the projection increases to $1.6 billion for 2025 and $1.59 billion for 2026.

Asset Condition Project Presentations

National Grid presented *a project* to address structural damage and deterioration on a 345-kV line in central Massachusetts. The company proposes to replace 19 wooden structures with steel structures, repair insulators on three structures, and conduct "minor maintenance" on 10 structures. This preferred solution is projected to cost $19.4 million, with an in-service date of mid-2025.

Eversource detailed its *plans to replace* 12 circuit breakers across two substations in New Hampshire, with an expected cost of $25.7 million. The company will replace breakers that use air compression systems, which it said pose "serious reliability risks." Eversource said it's ultimately aiming to replace all 127 of these breakers across New England and is prioritizing breakers at substations that have experienced frequent issues. ■

— Jon Lamson

ISO-NE News

Northeast Utility Commissioners Talk Costs of Grid Modernization

Causes of Region's High Electricity Costs Focus of Raab Roundtable

By Jon Lamson

BOSTON — Increasing electricity prices must be met with a greater effort to reduce peak loads and protect low- and moderate-income ratepayers, several Northeast utility regulators said at Raab Associates' New England Electricity Restructuring Roundtable on Sept. 20.

"There is no question that affordability is being strained today," said Ron Gerwatowski, chair of the Rhode Island Public Utilities Commission, adding that electricity costs are likely to remain high for the foreseeable future.

U.S. Bureau of Labor Statistics *data* shows the Northeast has some of the highest electricity prices in the country, only rivaled by parts of the West Coast. The costs associated with transmission and distribution system upgrades and grid decarbonization could push rates even higher.

While investments in grid infrastructure and renewable generation may benefit ratepayers in the long-term, Gerwatowski stressed that many customers are "not worried about whether electricity rates will stabilize in the long-term, they're worried about paying their electricity bills today."

However, Gerwatowski also emphasized that it is "oversimplistic, and not reasonable, to blame the strain on affordability solely upon the costs associated with any one individual initiative, especially our initiatives that are designed to advance renewable energy deployment in order to address carbon emissions."

He said the region's rates are being pushed up by inflation, the increasing need to replace aging grid infrastructure, high winter gas costs, utility biases toward capital expenditures and the decreasing availability of easy energy efficiency improvements.

Massachusetts Department of Public Utilities Commissioner Staci Rubin said LNG volatility and reliance on the Everett LNG import terminal has also contributed to high rates, along with *predatory* third-party competitive suppliers.

From left: Commissioner Carrie Gilbert, Maine PUC; Commissioner Staci Rubin, Massachusetts DPU; Chair Ron Gerwatowski, Rhode Island PUC; and Janet Gail Besser, moderator | *© RTO Insider LLC*

Rubin said the ratepayer benefits of long-term renewable energy contracts are not often apparent to customers, noting that "things like price suppression do not actually show up on your bill."

At the same time, "the entire clean energy transition cannot be funded entirely through electricity bills — we need to look for outside sources of funding," Rubin said, emphasizing the importance of seeking and using all available federal funding.

Maine PUC Commissioner Carolyn Gilbert added that electricity bills are a "somewhat regressive means" to fund the clean energy transition. She said states must push to unlock cost and emissions savings from time-varying rates, echoing similar comments made by Gerwatowski.

"Any time there's a potential to save money I think we have to go after it," Gilbert said.

Lisa Wieland of National Grid, which owns electric and gas utilities in Massachusetts, said the company is this fall beginning a multiyear process of deploying advanced metering infrastructure (AMI) in the state. The company expects to bring AMI to between 750 and 1,000 of its approximately 1.3 million customers in the state by the end of the year and plans to roll out time-varying rates once it has completed most of its AMI deployment.

Gas Decarbonization

Reducing the region's reliance on natural gas is essential to keeping energy costs manageable in the region, said Bradley Campbell, president of the Conservation Law Foundation.

"The energy transition can drive affordability," Campbell said, adding that "the message that the clean energy transition is antithetical to affordability" is "a false narrative being pushed heavily by the fossil fuel industry."

While the Massachusetts DPU has ruled the state will need to chart a course off gas to meet its climate goals (*DPU 20-80*), natural gas consumption in the region for buildings and electricity generation has ticked up in recent years, according to state's most recent emissions *inventory update* and *data* from ISO-NE.

Gas prices remain a key driver of the region's energy costs, with pipeline constraints driving up gas prices in the winter and leading to expensive out-of-market contracts for LNG.

ISO-NE News

Enbridge, which owns the major natural gas pipeline into the region, has proposed a major project to expand its gas transmission capacity into the region, to the staunch opposition of climate activists.

"In a region where ratepayer misery is driven by gas price volatility, the message that we should double down on natural gas dependency in New England is not only unsound, it's immoral," Campbell said.

Disagreements between the Massachusetts Senate and the House over how aggressively the state should move away from gas have derailed progress on a wide range of other climate and energy issues, including a widely agreed-upon proposal to reform the permitting and siting processes for clean energy infrastructure. (See *Mass. Gov. Healey Includes Permitting Reform in Budget Proposal*.)

"Massachusetts siting reform failed to pass, despite broad consensus, because gas utilities would not agree to take the first steps needed to implement the DPU's order on the future of gas," Campbell said. He criticized both the administration of Massachusetts Gov. Maura Healey (D) and the utility industry for not moving more quickly to prepare for the transition away from gas.

At the same time, he expressed optimism about the administration's newly created Office of Energy Transformation, which he said could "could provide the venue to forge consensus among stakeholders on how to speed the energy transition while advancing affordability."

From left: Dan Berwick, New Leaf Energy; Lisa Wieland, National Grid New England; Claire Coleman, Connecticut Office of Consumer Counsel; and Janet Gail Besser, moderator | *© RTO Insider LLC*

Solar Stagnation

Dan Berwick, CEO of New Leaf Energy, expressed concern about the stagnation of solar development in the state, noting that 2023 was "the lowest year for solar deployments in over a decade" in the state, with 2024 tracking to be even lower.

While large-scale solar projects are the cheapest form of solar in the state, "we've all but stopped doing big solar projects in Massachusetts," Berwick said. He attributed the slowdown to interconnection delays and constraints on where solar projects can be sited to receive support from state programs.

"We have a much more restrictive land use framework for our clean energy developments than we do for other types of developments," Berwick said, also expressing hope that "there's an outcome that we ought to be able to find alignment on." ■

MISO and Monitor at Stalemate over Need for $21B Long-range Tx Plan

By Amanda Durish Cook

INDIANAPOLIS — MISO's quarterly public meetup with its board of directors put on display the unrelenting rift between the RTO's planners and the Independent Market Monitor over MISO's $21 billion in upcoming long-range transmission planning.

At a Sept. 17 Markets Committee meeting of the MISO Board of Directors, MISO IMM David Patton encouraged a recess on the proposed $21 billion second long-range transmission plan (LRTP) portfolio until MISO agrees to rework its 20-year view of its system and the benefit estimation of the transmission.

Patton repeated concerns he raised earlier at a stakeholder workshop on MISO's second LRTP portfolio, which MISO hopes to advance for board approval by the end of 2024. (See *MISO Says 2nd Long-range Tx Plan to Cost $21B, Deliver Double in Benefits*.)

"We should pause this process and get to the bottom of this before we allow it to move on," Patton told board members. "The problem is we don't have a credible, 'what-will-the-world-look-like' scenario if we don't build this transmission."

Senior Vice President of Planning and Operations Jennifer Curran said MISO believes it has devised a valuable portfolio and stands by its conservative, 1.9:1 benefit-to-cost estimate.

"I think we have a different philosophy on benefits that leads to a fundamental disagreement," she told the board.

"We can't perfectly predict the future. But through the use of scenarios, we can develop the most robust portfolio using the modeling we have available today," Vice President of System Planning Aubrey Johnson said.

Johnson said the LRTP can be interpreted as "skating to where the puck will be." He said recent load growth shows MISO's top-end, most radical planning scenario is likely, when some stakeholders thought it outlandish five years ago.

Johnson said even scaling back MISO's decarbonization benefit for areas of the footprint where the value of decarbonization isn't openly acknowledged, the portfolio still would have 1.3:1 benefit-cost ratio.

Multiple stakeholders urged MISO not to entertain the IMM's request for an assumptions and benefits rework.

IMM David Patton (center) addresses the Markets Committee of the MISO Board of Directors on Sept. 17 | © *RTO Insider LLC*

ITC's Brian Drumm said MISO leadership should reject the Monitor's calls to "develop and test against an alternate reality" regarding LRTP transmission planning.

Drumm said it's "irresponsible and dangerous" for Patton to assume MISO won't experience a major load shed event simply because it never has or assume members will make plans independently to dodge one.

"Stakeholders have chosen to solve the reliability imperative through long-range planning and particularly" the second LRTP portfolio, Drumm argued. "The IMM's request is inappropriate because MISO's role is to plan regional transmission, not to serve as an integrated resource planner."

Drumm added that the industry is aware that significant loss of load events will occur again and become more pronounced by extreme weather. He said avoiding just one widespread load shedding event can more than cover the $21 billion price tag of LRTP II.

The Union of Concerned Scientists' Sam Gomberg said MISO isn't going far enough in incorporating climate risk assessments in long-range transmission planning. He said MISO should anticipate changing weather patterns to inform system planning so it doesn't end up trying to solve the challenges of extreme weather on the fly in the control room.

Gomberg also said MISO is correct to value decarbonization in transmission planning. He said Patton's argument that federal production tax credits already fully value decarbonization and MISO's benefit metric is redundant "borders on absurd" and gives too much credit to Congress to objectively put a price on the social cost of carbon.

MISO Director Phyllis Currie asked if MISO has a stance on planning for increased climate impacts on the system.

"I think our primary objective is to reflect our members' objectives. We really follow the lead of our members [rather] than taking an independent view of climate change," Curran said. However, Curran added that from an operations standpoint, MISO uses analytics and machine learning to forecast weather events that historically haven't occurred.

"David Patton consistently misunderstands the benefits of regional backbone lines … [and] doesn't like long-term scenario-based planning," Sustainable FERC Project attorney Lauren Azar argued to board members. Azar said the IMM appears to want MISO to "go backwards" into the "balkanized system" that existed before the RTO's creation.

Azar rhetorically asked board members to place a monetary value on the 210 lives lost when the lights went out on Texas residents during Winter Storm Uri.

Azar said the IMM should stick to its original purpose of "mainly markets" and advised MISO not to pay for the IMM's opinions on transmission planning through its IMM budget.

The MISO IMM has made some stakeholders uneasy with his interest in MISO's long-range transmission planning and public criticism of the 20-year fleet and benefit estimates MISO uses. Since last year, some have said the IMM oversteps his role.

MISO's board of directors has included a $250,000 allowance in the Monitor's $10 million *budget* next year to "monitor ratings and identify transmission withholding and compliance" associated with ambient adjusted line ratings requirements MISO will roll out under FERC Order 881. The line item and data collection of transmission data caused consternation among MISO transmission owners.

MISO staff will be "actively discussing what data" transmission owners must provide, MISO Director Trip Doggett said. ■

MISO Members See No Easy Fix for Making Transition Affordable

By Amanda Durish Cook

INDIANAPOLIS — At their quarterly meetup, MISO members largely agreed there won't be an easy path to achieving decarbonization affordably for customers.

"We've gone from talking about rates, to talking about energy burden to now talking about energy wallet," Sarah Freeman said, introducing members' chosen topic, "Affordability, Sustainability and Reliability," at a Sept. 18 meeting of MISO's Advisory Committee.

"I really don't think we're prepared for what the transition is going to cost in the next five to 10 to 15 years," said Michelle Bloodworth of coal advocate America's Power. Bloodworth said customers of rural power cooperatives will be particularly hard hit.

Arkansas Public Service Commission consultant Keith Berry said affordability is a chief issue in MISO South, which he said contains some of the poorest residents in the nation. He said he worries what MISO's third long-range transmission plan (LRTP) portfolio — which will focus on MISO South — may do to customer bills.

"We look with some trepidation on what the costs of Tranche 3 might be," Barry said.

Sam Gomberg, Union of Concerned Scientists | *© RTO Insider LLC*

The Union of Concerned Scientists' Sam Gomberg said MISO's Environmental Sector views the three words as interconnected.

"If electricity is cheap, but it's fouling your waters and making our planet uninhabitable, then it's not affordable," Gomberg said.

Clean Grid Alliance's David Sapper said to further all three, MISO should "unlock the queue without resorting to a queue cap," finding ways to bring new resources online quickly.

"Resource expansion is the cornerstone of competition, so we need to get the queue moving," Sapper said. He also said MISO's transmission owners should use grid-enhancing technologies and dynamic line ratings to leverage the most they can from the existing system and host the greatest number of new megawatts.

Other members said some transmission projects will be better than others at delivering value.

Yvonne Cappel-Vickery, of the Alliance for Affordable Energy, said the industry should work to put a stop to inefficient transmission "overbuilds that starve the regional transmission planning process."

Cappel-Vickery said some utilities "flock" to new power plants and expensive local lines that come "at the expense of bringing lower-cost resources" to their territories. She said the problem is particularly pronounced among utilities that own transmission and generation.

LS Power's Sharon Segner also said comprehensive, regional planning needs to trump the local projects that are ubiquitous in MISO's annual transmission planning.

Gomberg said members must ask themselves if they're willing to bear near-term costs for long-term benefits.

"If we underbuild, we're going to leave benefits on the table and risk affordability, sustainability and reliability," he said, adding that regional transmission needs to be "smart and targeted."

ITC's Brian Drumm | *© RTO Insider LLC*

ITC's Brian Drumm said there's no substitute for transmission to achieve all three objectives. He said there's current evidence that MISO and members have been underbuilding for years.

Iowa Utilities Board Member Josh Byrnes agreed the system to date has been underbuilt.

Multiple stakeholders said bills are opaque and confusing for customers and said some efforts from the industry to help ratepayers understand what's in their bill could go far.

Gomberg called for a greater commitment to transparency from utilities and MISO but added the simple fact is shareholder-beholden utilities exist to make money.

Gomberg said utilities may include "line items for things that they don't want to pay for" in customer bills, "chip away at regulatory oversight" and approach state commissions with "inflated costs" in rate cases.

"That's just the world we live in," he said, qualifying that he wasn't taking a shot at capitalism.

MISO's Advisory Committee underway Sept. 18 in Indianapolis | *© RTO Insider LLC*

In a separate discussion on the state of MISO's seams, Sustainable FERC Project's Natalie McIntire said MISO ought to do more to build cross-border transmission.

"As the energy transition occurs and more and more renewables are added to the system and weather events get more extreme, the ability to share across our seams is going to be more important," she said.

McIntire said MISO so far has provided "very little to no" insights into the scope of their recently announced interregional transfer capability studies with PJM and SPP.

On the other hand, the Coalition of Midwest Power Producers' Travis Stewart said MISO might need to reevaluate "the amount that we lean on our neighbors."

Stewart said with PJM anticipating supply shortfalls, MISO soon won't be able to rely on the few gigawatts it receives daily from its eastern neighbor.

"Those megawatts are going away," Stewart warned, saying MISO would be well-served by internally becoming resource and energy adequate so neighbors can begin to lean on MISO.

Vice President of System Planning Aubrey Johnson said seams projects might have been inhibited thus far because other RTOs haven't been as interested in scenario-based long-range transmission planning as MISO has been.

"Ultimately, I do think there's an attitude of 'solve your own problems first,'" Johnson said. He added that MISO's neighbors' interest in interregional projects might grow after they approve their own major portfolios.

"I think Order 1920 is going to bring the other regions along," Drumm agreed. ■

MISO News

ITC President Krista Tanner Pushes for Permitting Legislation

By James Downing

WASHINGTON — Transmission policy has made progress lately, but ITC President Krista Tanner came to Capitol Hill to get one more item over the finish line: the permitting bill.

A bill cleared the Senate Energy and Natural Resources Committee with a bipartisan, 15-4, vote over the summer, and Tanner said she hopes it can become law. (See *Manchin-Barrasso Permitting Bill Easily Clears Committee*.)

"There's widespread recognition that permitting reform is needed, and it's coming from all corners," Tanner said in an interview. "So, certainly, proponents of the IRA want to see this, because we're not going to see the benefits of the IRA or achieve our climate goals if we don't have the permitting. I mean, this is the last step that we need. Even if that's not your perspective, we're seeing energy demand growth in this country for the first time in 50 years. And so, we know that we need a resilient grid to connect new generation to serve new load."

ITC Holdings is a transmission-only firm that owns most of the power grid in Michigan and Iowa and does business in five other states: Minnesota, Illinois, Missouri, Kansas and Oklahoma. While it can get through many of the more local projects in its service territories without issue, ITC's joint Cardinal-Hickory Creek project with ATC and Dairyland Power Cooperative crossed the Mississippi River between Iowa and Wisconsin, cutting through a federal wildlife refuge in the process.

Nothing in the permitting bill passed by committee "guts" the National Environmental Policy Act and its requirements, but it would limit the amount of litigation involved in building transmission, Tanner said.

"On Cardinal-Hickory Creek, we had five different lawsuits, five different injunctions. We ultimately prevailed and found that we did, in fact, comply with NEPA and follow the appropriate process," she added. "And so, it's really the litigation and the injunctions that created a lot of delays on this project. And those delays aren't inexpensive. Anytime we start and stop a project, that adds cost to the project."

The line is poised to go into service as soon as this week, as the section crossing the river and the refuge has finally been built. The 102-mile line needed permits from Iowa, Wisconsin and several federal agencies that all had different processes, opening it up to multiple avenues for litigation.

Construction of the Cardinal-Hickory Creek transmission line | *ATC and ITC Midwest*

While it did cross a refuge, ITC and the other backers tried to avoid affecting land in other areas, favoring existing rights of way. But it had to cross the Mississippi River at some point, and that section drew significant opposition. While the line did bring up land use issues, it will help connect significant amounts of clean energy to the grid.

"We have 160 renewable projects waiting to come online for this project, and they represent over 24 gigawatts of clean energy," Tanner said. "We're not going to achieve our clean energy goals if we don't have the transmission to bring the clean energy onto the grid."

One way to avoid such delays is to work with affected landowners and communities on the front end to address their concerns.

"Landowners and communities bear the burden of these lines on behalf of everyone, right?" Tanner said. "And so, it's really important that you bring them in from the beginning. You talk to them about the need of the line, how it helps their community, not just the region, but their community."

ITC will show communities what a proposed substation would look like and what facilities it would serve to indicate how it could provide local benefits. The firm works with landowners on where exactly transmission poles should be placed, and Tanner said it once even leased some other land for an affected landowner to hunt on because transmission line construction stopped them from using their own property.

FERC Order 1920 has a lot of commonsense transmission planning rules and is in line with what ITC has advocated for some time, Tanner said. MISO transmission practices also line up with the rules, which should solidify how things are done there, she added.

"I think it will quell the debate because, you know, cost allocation, all of these things remain contentious, and it seems like nothing is ever fully decided," Tanner said. Having Order 1920 in place "just solidifies that this is the way we do planning in this RTO. We're not going to keep revisiting these things."

Some have argued that the forward planning MISO is engaged in, and FERC has backed in 1920, could lead to transmission overbuild. Tanner said she doubts that, especially based on what happened when MISO completed the Multi-Value Project lines.

"They were at capacity the minute they were built, because we thought too small," Tanner said. "And so, I think we have to stop thinking small as a country and start betting on our economy and our manufacturers."

While 1920 was an important step, FERC could add more "regulatory certainty" around returns on equity to help get transmission built, Tanner said. FERC has had an open proceeding in RM20-10 on incentives for several years and Commissioner Mark Christie has called for reforms in numerous dissents to orders approving them for specific projects.

Those unresolved ROE cases create uncertainty, Tanner said. "And given the need for investment, this is not the time to create uncertainty."

Tanner also said she would like to see FERC further curtail competition in transmission planning and development. The system under Order 1000 has failed largely because independent developers lack the local knowledge of a firm like ITC, she said, which is transmission only but operates in specific communities.

"The only thing that Order 1000 has succeeded in is causing at least a year's delay in projects, but it has not reduced the cost," she added. ■

MISO News

MISO Board Week Covers Supply Worry, SoCal Utility Exec Addition, $400M Budget

By Amanda Durish Cook

INDIANAPOLIS — The MISO Board of Directors hit the high notes of resource adequacy anxiety, a possible board addition with experience at Southern California Edison and an annual budget that will creep past $400 million for the first time.

More Supply Alarms

In what's becoming a familiar refrain, Senior Vice President of Markets and Digital Strategy Todd Ramey cautioned board members that MISO's capacity soon will fall short of serving ever-increasing load.

MISO needs a "dramatically accelerated pace of new build," Ramey said at a Sept. 19 board meeting. He stressed the RTO needs dispatchable, long-duration resources, noting that member plans submitted under MISO's 2024 Regional Resource Assessment show anticipated additions primarily are weather-dependent.

Ramey said members should consider "deferring retirements until other options are available." He also said members might question whether their clean energy goals "balance and add up well" against reliability requirements. He said some could relax target time frames.

"Without delays we've had to date, we'd be in a whole lot of trouble," MISO Director Todd Raba said.

However, MISO Director Mark Johnson said retirement delays should be considered "as short-term lever."

Director Phyllis Currie agreed retirement postponement should be a "short-term step" especially considering the threat of climate change and that MISO "should demonstrate an openness" to new technologies. "I think our posture has to be one that we don't sound like we're counting on delays."

Ramey added that MISO is sitting on 55 GW of projects with approved interconnection agreements but that remain unfinished, stalled largely by lurching supply chains.

Tyler Huebner, formerly of the Wisconsin Public Service Commission and now with Google, said load growth from computing and manufacturing presents the U.S. with an opportunity to "reinforce" its reputation for ingenuity and intrepidness.

Huebner said Google is working with MISO members to identify the most appropriate locations to site facilities and is working on creative solutions to unlock new capacity.

"We strive to be good grid citizens," he said.

MISO and its directors are set to discuss the footprint's load growth trajectory through 2030 and the changing resource portfolio at a nonpublic *MISO Board Strategic Planning Session* near Seattle on Oct. 28.

Southern California Edison Retiree Poised to Join Board

MISO members will vote on whether to install two familiar faces alongside a retired Southern California Edison executive to their board of directors next year.

MISO announced that membership next week can begin casting votes of support for former Southern California Edison senior vice president Erik Takayesu and current board members Nancy Lange and Mark Johnson. Electronic voting will open Sept. 26 and run through Nov. 1.

Lange is running for a third and final term. Johnson, on the other hand, is seeking a fourth, three-year term that is possible through a waiver that allows him to exceed MISO's usual three-term limit.

At a Sept. 19 board meeting, MISO Director Robert Lurie said MISO's Nominating Committee this year paid particular attention to maintaining board expertise while introducing fresh perspectives. He said board members don't use the waiver lightly and noted the board is set to experience "significant turnover," with five directors reaching their term limits within two years. (See *Extensions Likely for MISO's Term-limited Board Members*.)

Lurie said the use of a waiver for one board member will provide some "continuity in a fast-changing world."

"MISO has several initiatives in flight, such as the LRTP, that are multiyear in nature," he added.

Johnson and Currie both expressed a willingness to stand for an additional term through a waiver of MISO's usual term limits. Ultimately, MISO's Nominating Committee advanced only Johnson for a waiver.

MISO considered 23 candidates found by search firm Russell Reynolds and ultimately interviewed eight candidates in person. Lurie said several candidates were equipped with system planning experience.

MISO's Board of Directors gathers Sept. 19 at The Westin Indianapolis. | *© RTO Insider LLC*

MISO's board elections require candidates to earn a majority of votes in support among membership. MISO members can vote for, against or abstain from selecting any of the candidates. The elections require a minimum 25% participation rate among MISO's approximately 140 voting-eligible members to achieve quorum. MISO will use Votenet Solutions to conduct its membership vote of the candidates.

The board, meanwhile, agreed to raise the base retainer for board members to $200,000 annually.

MISO Budget to Top $400M in '25

MISO's budget next year likely will climb to $403.7 million, a 7.7% increase from 2024, MISO members heard.

The proposed budget includes $370.6 million in base operating expenses and $39.8 million reserved for capital expenditures, with the total increase partially offset by interest income.

MISO plans to increase its current $0.47/MWh member rate to $0.51/MWh in 2025.

At a Sept. 18 Advisory Committee meeting, CFO Melissa Brown said lately there has been "a lot more volatility" in MISO's financials.

Brown said the labor market remains tight, and MISO still has a higher employee vacancy rate than it would like at about 6%.

Brown said calls with other RTOs' CFOs shows that FERC's recent transmission planning order is sending other grid operators into a hiring spree. She said she fears some of MISO's planning staff will be "poached."

"We're trying to do all we can to keep our existing system planning folks," she said. ■

MISO News

MISO: Hurricanes, Heat Wave Noteworthy Against Relatively Peaceful Summer

By Amanda Durish Cook

INDIANAPOLIS — MISO said it managed a milder summer overall compared to previous years, though it weathered two hurricanes and escalated into emergency warnings during a heat wave.

MISO served its summertime peak of 122 GW on Aug. 26, using two maximum generation warnings as the Midwest baked under a prolonged heat wave. (See *Late August Heat Wave Delivers 122-GW MISO Summer Peak*.) Otherwise, summer brought an 85-GW average load, closely following the average load of the three previous summers.

MISO's average $28/MWh real-time price throughout the season tracked cheap, $2/MMBtu coal and gas prices. The RTO experienced about 31 GW of daily generation outages and derates, lower than in previous years.

At a Sept. 17 Markets Committee of the MISO Board of Directors, Independent Market Monitor David Patton said MISO's summer peak would have been about 1.8 GW higher without voluntary demand response in the footprint.

MISO's board members and leadership praised operators for pulling through the overnight electrical island caused by Hurricane Beryl in early July. (See *MISO: Hurricane Beryl Caused Electrical Island in Texas*.)

"It's hard to believe it's been a while since we've been here, about three years," Executive Director of System Operations Jessica Lucas said about delivering a hurricane operations post mortem. She said MISO prepared for an above-normal hurricane season, but so far, storms have been scarce.

Lucas said the Category 1 Beryl nevertheless caused the loss of 73 MISO-operated lines and 250,000 customer outages, a "surprising" number for a "low-intensity" storm.

MISO reported all but one of the lines leading to a Southeast Texas load pocket knocked out of commission. Eventually, the remaining in-service line — a tie line with SPP — went down as well July 8. Prior to the final outage, MISO noticed more generation available in the load pocket than load to serve, leading it to direct all but one generator offline. MISO kept flows on the line at essentially zero to limit potential customer impacts. MISO was prescient to do so, Lucas said, because that remaining line eventually went out of service.

Lucas said she had the "privilege" of being in MISO's Little Rock, Ark., control room during the night to see firsthand how MISO, SPP and Entergy coordinated to resync the area to the bulk electric system.

The Markets Committee of the MISO Board of Directors in session Sept. 17 | *© RTO Insider LLC*

"Operating an island for over eight hours is quite a trick. One of my colleagues said it's like spinning a plate on a needle," Vice President of Operations Renuka Chatterjee said.

MISO Director Trip Doggett said the feat was the result of "heroic effort."

"I thought MISO did an amazing job of managing reliability during this event," Patton said. However, Patton added that southeastern Texas "by far" experiences the most load shedding in MISO.

Patton suggested that MISO "take a hard look at its capacity zones" and consider splitting up MISO's Zone 9, which contains Louisiana and southeastern Texas. He said the large zone and Louisiana's capacity-sufficient status mask the fact that southeastern Texas needs resources.

"It prevents the market from signaling that MISO needs to build more generation in this area," Patton said of the size of the zone.

MISO South's second hurricane over summer proved more uneventful, Lucas said.

MISO declared conservative operations Sept. 10-13 for its South region as Hurricane Francine made landfall in Terrebonne Parish on Sept. 11 with Category 2 force. At the time, Entergy reported upward of 300,000 customer outages. By Sept. 16, Entergy reported it restored nearly all customers in Louisiana and Mississippi.

"There was not nearly as much excitement as Beryl caused," Lucas said.

Lucas also noted operators navigated a "wind drought" lasting 11 hours July 21 and eight hours July 22 among its 31-GW wind fleet.

MISO defines wind droughts as periods during which wind output dies down to 500 MW or less for five or more hours. MISO said it has experienced 11 such events since 2020.

"As more weather-dependent resources are added to the portfolio, managing long-term, multiday resource droughts will be a challenge," Lucas said.

IMM Demands Tougher Demand Response Requirements

Despite summer 2024's lack of emergencies, Patton used his time slot for a summertime review to ask MISO to "beef up" testing to make sure load-modifying resources can deliver what they promise.

"So much of what we pay for demand response resources has turned out to be manipulative, or not useful to the system," Patton said.

Patton said a review of MISO's demand response showed that up to 25% of DR resources submit "mock tests" for their accreditation in lieu of real testing, which presents opportunities for fraudulent data submissions.

Patton said the review also uncovered one commercial retail end-use customer signed up with multiple market participants for the same load and some "unconsummated contracts with critical information redacted that prevent MISO verifying the DR amount or validity."

Patton also said MISO should stop allowing load-modifying resources to cross-register as both capacity resources and emergency demand response. He said resources should commit to selling one or other, or better yet, MISO should eliminate its emergency demand response program. He pointed out MISO never actually has called on emergency demand response.

Patton's suggestions come after multiple demand response resources in MISO have been disciplined for deceptive behavior.

Over the past two years, FERC has caught three companies manipulating MISO's demand response market and collecting unwarranted payments. The commission found that an air separation facility in Indiana accepted payments for fictitious load reductions, an Arkansas steel mill made phony use reductions spanning years, and that an obscure, Texas-based LLC formed to sell in-car ketchup holders fraudulently enrolled customers and made bogus DR offers in three capacity auctions. (See *FERC Catches Ketchup Caddy Co. in Another Fake DR Scheme in MISO*.) ■

Cautious Optimism at Alliance for Clean Energy NY Conference

By Vincent Gabrielle

A city bus trundled to a halt on a dusty gravel road just south of Albany at the *Port of Albany's offshore wind expansion project*. The passengers, various representatives from labor, the energy industry and the Alliance for Clean Energy New York, shielded their eyes from the late afternoon sun, staring across several acres of flat, riverside land.

"If you look out to the east side, you'll see a line of trees that stretches about eight acres," said Richard Hendrick, CEO of the Port of Albany. "We engaged early on with the First Nations people who have sacred land on the east side of the Hudson River. … They suggested if we just keep that buffer of trees, none of what we're doing here will impact their view."

Hendrick and his staff proudly showed off the newly created, fully permitted site they hope will be the center of offshore wind tower manufacturing for New York's emerging market. Hendrick's team had removed 30,000 tons of contaminated coal ash from roughly 100 acres of land and capped off the rest of the soil. Construction is entering final stages on a 400-foot steel bridge to connect the site to the rest of the port over a nearby creek.

Construction on a 500-foot wharf and dedicated substation are due to begin in early 2025.

Optimistic Outlook

The tour, forward looking and full of hope, put a period on the general theme of the Alliance for Clean Energy NY's fall conference. Industry players, regulators and elected officials generally were positive about the direction of New York's energy future despite recent reporting that the state would fall short of its 2030 climate goals.

"Our pipeline continues to grow," said Doreen Harris, president of NYSERDA, in her breakfast keynote address. "We have over 100 large-scale renewable projects in the interconnection queue. … These projects are getting built! Some of you may know that I've coined that summer of 2024 is the 'Summer of Shovels,' and you have kept me very busy celebrating."

Harris said that just 10 years ago, the renewable picture wasn't nearly as robust. She pointed to 1 GW of distributed solar installed last year and compared it to the roughly 50 MW the state was installing a decade ago.

Dorren Harris, President of NYSERDA, addresses the attendees of the Alliance for Clean Energy NY Fall Conference in Albany at the Capitol Center. Harris touted the recent completion of the South Fork wind farm off the coast of Long Island and highlighted various energy and transmission projects across the state. | *© RTO Insider LLC*

"If you take nothing else from these remarks, I want you to know that the renewable energy pie will continue to grow here in New York in the coming decades," Harris said. She said her goal is to accelerate the progress on renewables, and she encouraged industry representatives to participate in developing the new Clean Energy Standard.

"The phoenix has risen from the ashes here in New York, and we have collectively emerged stronger, smarter, wiser and more powerful," she said. "Make no mistake: This was a Herculean effort. But here in New York, we deliver on our promises."

Speeding up progress on siting, permitting and interconnection was the major theme of the morning's panel discussions. Department of Environmental Conservation interim Commissioner Sean Mahar told attendees he didn't want the DEC to be a barrier to renewable development.

"What we think we're doing right now is creating a more workable program," Mahar said, referencing wetland regulations. "We are structuring this program in the right way so as not to be a barrier to development, but to make sure development is happening in the right places."

In later comments, Mahar said DEC is working on ways to permit renewable energy development on brownfields and Superfund sites, to streamline the permitting process and to streamline mitigation efforts in places where renewables harm the environment.

Zach Smith, vice president of system and resource planning for NYISO, said the ISO implemented a new interconnection process to speed up the expansion of transmission and renewables.

"Our projection is that roughly three times the amount of generating capacity is needed in the next 20 years relative to today's system. Opportunities abound," Smith said. "What that capacity looks like, that's kind of a big question mark. There is not a single formula to this."

Smith said the upcoming Reliability Needs Assessment was conservative in its estimate of how much generation capacity would be interconnected. Some projects in the interconnection queue weren't considered as part of the assessment because they weren't far

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enough along. He said a finding of a reliability need wasn't necessarily "pulling the fire alarm."

"Rather, it's to flag the need for continued progress on resources in New York State, and we have had many," Smith said. "It's an opportunity for further resource development."

Endorsements for New York's Renewable Market and Kamala Harris

A lunch panel of renewable energy industry leaders said they were broadly optimistic about building new energy resources in New York.

"The main point here is that you have a very strong market signal about demand in New York, which makes it an attractive place to really think about a multiyearlong investment program," said Ben Koffel, chief commercial officer of Vineyard Offshore. He pointed to the high forecast load growth for the state. "If you were at this kind of conference a decade ago, people weren't talking about that. Everyone was talking about energy efficiency."

He said load growth in New York, combined with the state's willingness to "put its neck out there and be a leader," made the state attractive to energy investors.

"We don't see a tremendous amount of opportunity cost because New York is such a leader, particularly in the offshore space," Koffel said. "This is a marquee market globally. That's what we hear from our peers in Europe."

Mark Richardson, CEO of US Light Energy, a distributed solar energy company, was less enthusiastic about the near term for his industry segment in the state.

"Where the rubber hits the road in terms of deployment, distributed generation has been incredibly successful over the past several years," Richardson said. "From our perspective, the opportunity in that segment has slowed down dramatically, and it's a combination of infrastructure capacity, interconnection capacity, interconnection queues ... combined with a local stranglehold on the permitting process for smaller projects."

Richardson said New York, so far, has done a good job, but the distributed generation segment needs more help from the state to deal with local siting and permitting issues.

Clint Plummer, CEO of Rise Light and Power, said the industry had to find ways to get as much community support as it could while also designing projects that would be minimally impactful.

"People don't want big things in their backyards," Plummer said. "As a resident, I like that my voice has some impact on what can be built in my community where I live, and as a developer, it's a major source of annoyance. But it's a necessity."

Plummer said this meant going to public meetings and being willing to take the "endless barrage of criticism" that they bring, then adapting plans to mitigate, or avoid, impacts.

"You're never going to win everybody, but people will respect you for being a trustworthy partner," Plummer said.

Later, during a "lightning round" question, the topic of the election was brought up to the panel.

"I hope a year from now, Doreen is not the only President Harris that we know," Plummer said. "But practically speaking, this underscores why New York is a good place to be investing."

Plummer explained that a Harris presidency probably would be more pro-renewable than a second Trump administration. But if Trump were elected, New York's position of pushing for more renewable generation for the state still would make it an attractive spot to develop.

Koffel said that even if Trump wins, New York has a strong economic case for renewables now that the industry had gotten to its current size.

"Renewables is a big tent, and the industry touches a lot of people," Koffel said. "In the event that Trump is the president again, that tent will mobilize to talk about the benefits it's bringing to the region, the billions and billions of dollars of investment." ■

NYISO Offers Final Staff Recommendations for Demand Curve Reset

By Vincent Gabrielle

NYISO presented its final interim staff recommendations for the demand curve reset for 2025-2029 at the Installed Capacity Working Group's meeting Sept 10, with minor updates to some metrics.

The recommendations remain largely the same as the draft presented last month, with the two-hour battery energy storage system (BESS) as the representative lowest-cost peaker plant technology. (See *NYISO Presents Draft Recommendations for Demand Curve Reset*.)

As part of calculating the cost of new entry for a hypothetical peaker plant, Zach Smith, senior manager of capacity and new resource integration for NYISO, said the ISO opted to factor in land lease payments for the construction period for the hypothetical peaker. Interconnection costs were modified downward across all zones outside of Long Island. The new derating factor for the BESS also was discussed.

Smith said the interconnection costs were estimated to be higher because it was assumed that peakers would require 345 kV, but 200-MW battery storage systems can connect to lower-voltage lines, which costs less. "And it appears to be better aligned with the actual interconnection requests that we are seeing," Smith added.

The Analysis Group, NYISO's consultant on the reset, also updated net energy and ancillary services revenues to account for an operator of a BESS plant maintaining their state of charge to meet day-ahead schedules.

"The change here is that we force the battery to charge more before the peak load window," said Paul Hibbard, principal of Analysis Group.

Hibbard said the change causes negligible differences to net EAS revenue across all zones, aside from Long Island, which saw a 12% drop.

Derating Factor Headaches

Smith said NYISO was recommending a 2.5% derating factor for BESS peakers. The derating factor was calculated as a weighted average of the derating factors that batteries should expect to receive across their 20-year amortization period.

NYISO does not yet have a class average for BESS units. "The ICAP Manual (Section 4.5) currently establishes that the initial derating factor a new BESS would receive upon entering the ICAP market is based on the NERC class average equivalent demand forced outage rate (EFORd) of pumped hydro storage until three energy storage resources are participating in the ICAP market and have sufficient historical operating data to establish a 'NYISO class average' EFORd for energy storage resources," the ISO said.

The 2.5% derating factor is based on the assumption that any new BESS would have an initial 9.19% derating factor — the current class average for pumped hydro — for its first year of operation. The derating factor for the second year would be 5.6%, which is the average of 9.19% and 2%, which is the derating factor estimated by NYISO's consultants. NYISO then assumes a 2% derating factor for years 3 to 20 of the estimated life of the battery. The average over those 20 years is about 2.5%.

But this prompted questions from stakeholders.

"I don't understand how you can make this change without making companion changes to the manual," said Doreen Saia, of Greenberg Traurig. "The unit that comes online next year isn't going to get 2.5%. It's going to get 9.19% unless and until we make changes to our actual rules."

Smith clarified that the derating factor would be 9.19% for the first year and the average of 9.19% and the actual availability of the BESS for the rest of its operating life.

"A unit's derating factor, once it has sufficient operating experience, is always based on its actual production," Smith said.

Open Questions, Open Frustrations

Smith went over several questions NYISO was still reviewing, such as how to take into account sales tax for BESS labor, operations and maintenance costs; investment tax credits for the transmission lines to the plants; and costs of debt and equity.

Some stakeholders were unhappy that several longstanding questions were not answered and not addressed in the open questions. They expressed that they wanted to see cost declines for battery units included in the analysis.

"The ISO has recently shown the assumptions that it's doing in the study with the Department of Public Service and the transmission owners, and it shows an expectation of more than a 50% decline in battery storage costs over the next 10 years," said Mark Younger of Hudson Energy Economics. This meant a decline in revenues for the battery units; thus, NYISO's net cost of new entry was about 45% too low.

Another stakeholder was disappointed that NYISO was not proposing to include revenues for BESS units that come from outside wholesale markets, which could include incentive programs from the state and utilities.

"I think it severely overstates the net CONE of these facilities and therefore it will impose very high, unnecessary costs on New York consumers," they said. ■

| *Shutterstock*

PJM News

Constellation to Reopen, Rename Three Mile Island Unit 1

By Devin Leith-Yessian

Constellation Energy plans to reopen Three Mile Island Unit 1 under a power purchase agreement with Microsoft to sell about 835 MW to serve the company's data centers.

Constellation announced the reopening in a *press release* Sept. 20, exactly five years after it took the nuclear generator offline for economic reasons. In its new life, the generator has been renamed the Crane Clean Energy Center (CCEC) in memory of Exelon CEO Chris Crane, who died in April 2024. (See *Exelon to Close Three Mile Island*.)

"Powering industries critical to our nation's global economic and technological competitiveness, including data centers, requires an abundance of energy that is carbon-free and reliable every hour of every day, and nuclear plants are the only energy sources that can consistently deliver on that promise," Constellation CEO Joe Dominguez said in the announcement. "Before it was prematurely shuttered due to poor economics, this plant was among the safest and most reliable nuclear plants on the grid, and we look forward to bringing it back with a new name and a renewed mission to serve as an economic engine for Pennsylvania."

Constellation aims to bring the unit back online in 2028 and will seek a license renewal from the Nuclear Regulatory Commission to continue operating the generator through at least 2054. Restarting the unit will require a $1.6 billion investment, including upgrades to the turbine, generator and transformer. Safety and environmental reviews will be required from the NRC, as well as local and state permits. The adjacent TMI Unit 2, which partially melted down in 1979, is owned by Energy Solutions and is in the process of being decommissioned.

While the generator will interconnect with PJM, the power will be supplied directly to Microsoft, and no energy nor capacity will be offered in the RTO's markets.

Microsoft Vice President of Energy Bobby Hollis said the carbon-free energy provided by CCEC will help the company meet its clean energy targets. The PPA will be effective for 20 years.

"This agreement is a major milestone in Microsoft's efforts to help decarbonize the grid in support of our commitment to become carbon negative. Microsoft continues to collaborate with energy providers to develop carbon-free energy sources to help meet the grid's capacity and reliability needs," he said.

Three Mile Island nuclear power plant | *DOE*

Data center load has been a significant driver of rapidly increasing load forecasts in PJM and has been highlighted as one factor behind a spike in capacity prices in the 2025/26 capacity auction. (See "PJM Discusses 2025/26 Auction Results," *PJM MRC/MC Briefs: Aug. 21, 2024*.)

The RTO's 2024 *load forecast*, which is based on historic economic trends, includes large load additions in the AEP, APS, Dominion and PS zones, reflecting changes in consumption that utilities identified. Dominion estimated 2,666 MW of additional load in 2025, which it estimates will balloon to 21,563 MW in 2039. American Electric Power estimates 1,738 MW in 2025, growing to 3,624 MW in 2039.

Data centers have sought to co-locate with nuclear power plants, which would pull capacity out of PJM's market over the objections of utilities and state regulators. Talen Energy and Amazon Web Services reached an agreement this year to sell a data center Talen built adjacent to its Susquehanna Nuclear Plant and supply it with behind-the-meter energy.

PJM has asked FERC to approve an amendment to the generator's interconnection service agreement to reduce the maximum output, and capacity, the generator offers into PJM. Exelon and AEP filed a joint protest arguing that co-located load benefits from the wider transmission grid and should be subject to relevant fees. They also argued there are unresolved questions about how a novel configuration could affect the grid. The Pennsylvania Public Utility Commission filed in support of the utilities' protest (*ER24-2172*). (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

Pennsylvania Politicians, Nuclear Experts Support Reopening

Pennsylvania Gov. Josh Shapiro (D) gave the reopening his support in a statement provided through Constellation's announcement, saying the state's nuclear industry provides "safe, reliable, carbon-free electricity."

"Under the careful watch of state and federal authorities, the Crane Clean Energy Center will safely utilize existing infrastructure to sustain and expand nuclear power in the commonwealth while creating thousands of energy jobs and strengthening Pennsylvania's legacy as a national energy leader."

That support was echoed by state Rep. Tom Mehaffie (R), U.S. Rep. Scott Perry (R) and Bart Shellenhamer, chair of the Board of Supervisors for Londonderry Township, where the CCEC is located.

"This unit was a good neighbor to Londonderry Township and our surrounding region for 45 years, with a workforce dedicated to contributing to area nonprofits and supporting the local economy," Shellenhamer said. "The Crane Clean Energy Center will bring billions in new infrastructure investment and help support area businesses, schools and public services that improve quality of life for the whole region."

Michael Goff, acting assistant secretary of the U.S. Department of Energy's Office of Nuclear Energy, said the reopening is a milestone for Pennsylvania and the country. "Always-on, carbon-free nuclear energy plays an important role in the fight against climate change and meeting the country's growing energy demands," he said.

Constellation purchased TMI 1 in 1999 and operated the unit through 2019, when it opted to deactivate the generator rather than buy more fuel. The company asked the Pennsylvania General Assembly to pass subsidies for the plant's continued operation years ahead of the retirement. While both chambers had bills on their dockets, their prospects were unclear. (See *Pa. Lawmaker Contends TMI Rescue Unlikely*.) ■

PJM News

FERC Dismisses Muni's Complaint Against Dominion over RGGI Charges

By James Downing

FERC has dismissed a complaint the Virginia Municipal Electric Association (VMEA) filed against Dominion Energy's Virginia Electric Power Co. (VEPCO) alleging the utility overcharged its members $2.8 million (*EL24-99*).

The commission declined to assert primary jurisdiction over the dispute, which it can do at its own discretion.

VMEA is a wholesale customer of Dominion's utility, and it argued the improper charges were related to the Regional Greenhouse Gas Initiative. VMEA has a full requirements electric service contract with VEPCO, with includes charges based on a formula rate that includes the Uniform System of Accounts, Account 509, as an input.

VEPCO exceeded the RGGI cap in 2021 and 2022, requiring it to spend $137.7 million and $123.5 million in emissions allowances. The utility recovered $84.2 million of that under a rider the State Corporation Commission (SCC) approved.

The rest of the money, $177.1 million, initially was supposed to be recovered in VEPCO's 2023 biennial rate review, but VMEA said the utility told state regulators that amount would be "deemed recovered" and would not be recovered in future rates.

VMEA claimed the $177.1 million should not have been included in Account 509. It was, and that led to the claim of being overcharged $2.8 million. The association wanted FERC to order Dominion to implement its formula rate without those charges in the account.

Virginia Power told FERC the SCC never disallowed recovery of the RGGI costs, and they were properly included in the rates charged to its retail customers and wholesale customers like VMEA.

The utility initially recovered RGGI costs through the rider, but it got rid of that once Gov. Glenn Youngkin (R) decided to withdraw from the multistate carbon market that had been entered into under his predecessors.

The SCC allowed VEPCO to recover the $177.1 million in its base generation rates in a June 2022 ruling, the utility told FERC. Its deal with VMEA also allows the utility to recover RGGI costs related to its service.

In declining jurisdiction over the dispute, FERC said it did not have expertise compared to the SCC or a state court to adjudicate the dispute. The issue also does not require any uniformity of interpretation for FERC because the facts are unique to the dispute and the complaint also does not raise any broader policy issues relevant to FERC's jurisdiction.

"Resolution of this matter does not require the commission to interpret its accounting rules and regulations; rather, the dispute concerns the factual issues related to the specific terms of the agreement and the SCC's decisions in a series of retail ratemaking orders and proceedings," FERC said Sept. 19.

Commissioner Mark Christie, who chaired the SCC before taking his position at FERC in January 2021, did not participate in the case. ■

Chesterfield Power Station in Chesterfield, Va. | *Southwings*

PJM News

Dominion CEO Says Virginia Well Poised to Meet Growing Demand

By James Downing

MCLEAN, Va. — A growing economy driven by new data centers has demand surging in Dominion Energy's utility territory, CEO Robert Blue said in a speech Sept. 20.

"Demand for electricity is growing at levels not seen since the years following World War II," Blue said. "We hit new summer demand peaks in each of the past four years. This year, we've had not just one peak, but a whole series of them. In fact, seven out of the 10 highest system peaks that Dominion Energy has ever seen took place in a single two-week period this summer."

That was in line with Dominion's forecast, and there is no sign of it stopping anytime soon, Blue said at a luncheon hosted by bipartisan business group Virginia FREE.

PJM expects demand in Dominion's territory to rise by 85% over the next 15 years, which is far more than it had to deal with in the previous 15, Blue said. That is going to have impacts on reliability, affordability and the transition to cleaner energy, he said.

The utility needs to maintain resource adequacy not just for its residential customers, but for large government and business customers in the D.C. area.

"Some of the entities we serve include the Pentagon, the CIA, the NSA and seven FBI field offices," Blue said. "As many of you know, around two-thirds of the world's internet traffic passes through Northern Virginia, so it's no exaggeration to say [that] if we don't execute on our mission, people around the country and even around the globe can't execute on theirs."

Blue said Virginia's policies have prepared the firm to handle continued growth by allowing it to build several new natural gas plants around the state in recent years, but given how much demand is growing, it will need more supply.

"We're going to have to add more generation and more transmission, and we won't be able to match rising customer needs with renewable generation alone," Blue said. "Now understand, we're adding renewable resources at a rapid pace ... but we're also going to need other forms of generation to step in when the weather doesn't cooperate, as well as during periods of high demand, such as cold snaps and heat waves."

That includes building more natural gas plants, preserving Dominion's existing nuclear capacity and perhaps building new nuclear resources as well. (See *Dominion Issues RFP for Small Modular Reactor at North Anna*.)

The Virginia Clean Economy Act requires carbon neutrality by 2045; Blue said Dominion has already cut its emissions in half since the early 2000s, as it has replaced coal plants with natural gas. The former's share of the company's generation mix has plummeted from over half in 2005 to about 10%.

"That's had a substantial impact on our emissions profile," Blue said. "It's also given us the confidence to layer in more renewables, knowing that when the weather isn't cooperating, gas-fired generation can step in and support our customers."

A decade ago, Dominion had no solar; now it has one of the largest portfolios of any utility. And the Coastal Virginia Offshore Wind Project is moving ahead on budget with construction on schedule, even as offshore wind in the Northeast has run into many issues.

"One big reason we've succeeded where others haven't is Virginia's regulated utility model, which requires us to demonstrate prudency before we can move forward with the project," Blue said. "Indeed, I would say 'prudency' is the defining characteristic of Virginia's regulatory compact, and that distinguishes our state from others that have recklessly deregulated their electricity markets."

Blue said utility rates are higher in deregulated states, and unscrupulous retailers use deceptive and high-pressure marketing techniques on vulnerable consumers. The winter storm of February 2021 wreaked havoc in Texas — a state often held up as the model for restructuring retail power markets, he added.

Virginia is not the only traditionally regulated state in PJM, but it is part of a minority, as states like Pennsylvania, New Jersey and Maryland have all opened up their retail markets to competition and given up some authority over generation in the process.

In 2020, Virginia imported 18% of its power from other states in PJM, but with the surge in demand, that figure is up to 37% so far this year, Virginia Department of Energy Director Glenn Davis said in remarks later during the event.

Davis said Virginia Gov. Glenn Youngkin (R) has endorsed an "all-of-the-above" energy policy that includes all traditional forms of energy, as well as new, cleaner ones. One of the administration's goals is to ensure Virginia has enough power that it does not need to rely on imports from other states, he said.

Dominion CEO Robert Blue | © *RTO Insider LLC*

Imported power "has helped us meet our short-term demand because of our growing economy; it also gives us some serious long-term concerns," Davis said. "Relying on imported power from PJM means that decisions made by states outside of Virginia — by the other 12 PJM states — have a direct impact on the reliability and cost of the energy supply."

Dominion gets several benefits from being in PJM, especially with its long-term, cost-effective regional transmission planning that helps it meet load growth, spokesperson Aaron Ruby said. PJM's wholesale power markets also ensure the lowest-cost power is available for its customers every day.

"With that said, we agree we don't want to be over reliant on out-of-state power, which is why we believe in the regulated model," Ruby said. "It gives Virginia utilities and our customers more control over our own power supply, which is the best way to ensure our power remains reliable, affordable and increasingly clean." ■

SPP Pushes Back on Western Market Delays

RTO Files Response to FERC's Deficiency Letter on Proposed Tariff

By Tom Kleckner

The three independent SPP board members providing oversight of the RTO's Markets+ development in the West have called for policy- and decision-makers to allow the process to "follow its natural course."

In an open *letter* released Sept. 19 and addressed to the Pacific Northwest congressional delegation, Western state regulators and the stakeholder-led Markets+ Participant Executive Committee (MPEC), the directors said delaying decisions to allow other market options to more fully develop will lead to uncertainty and prevent some interested participants from benefiting.

"Extended delays could lead to market participant uncertainty about their market choices and, due to the need for adequate market footprint for Markets+ to succeed, deny interested parties the possibility of becoming beneficiaries of its unique design," wrote Director Steve Wright, chair of the Interim Markets+ Independent Panel (IMIP), fellow SPP Director Elizabeth Moore and board Chair John Cupparo.

"This independent panel understands some parties' wishes to delay decisions while other market options more fully develop. Making Markets+ a reality requires continued funding, though, and funding requires that Western entities be allowed to negotiate and execute agreements on the defined timeline," the IMIP said. Western market participants "were clear that anything other than accelerated market development" would undermine the day-ahead market's viability and would "hence not be worth their time or money."

"It is our belief that the accelerated formation of the Markets+ option has already provided benefit to Western consumers," the IMIP said. "There are many examples of competition improving market design and governance of several market alternatives that will be available to the West.

"SPP and participants in Markets+ development anticipated short delays for steps like FERC tariff approval, but longer delays could disrupt healthy competition, threaten an as-soon-as-possible go-live date for Markets+ and ultimately deny the West a solution to many of the challenges it faces," the directors added.

The RTO has been involved with several *service offerings* in the Western Interconnection, some that predate the COVID-19 pandemic. It was approached in 2021 by Western entities interested in designing a market. Work with *37 stakeholders* began the next year and has resulted in a governance structure that has produced a tariff and market protocols.

SPP filed the proposed Markets+ tariff with FERC in March. However, the commission issued a deficiency letter in July asking the RTO to respond to 16 issues it found lacking in the design (*ER24-1658*). (See *FERC Finds SPP Markets+ Tariff 'Deficient' in Several Areas*.)

As if to emphasize the need for speed, SPP filed a *response to FERC's deficiency letter* Sept. 20, more than a week ahead of the due date. The RTO said the deficiency letter is part of a "routine process" it has been participating in for years. It said none of the commission's questions indicate a "serious risk." (See *SPP Dispels Concerns over Markets+ Deficiency Letter*.)

The grid operator used 33 pages to answer the 16 questions, which dealt largely with transmission issues. It asked FERC for an order by Nov. 20.

The IMIP said the deficiency letter was "consistent with our expectations" for the market's approval and that SPP's response to FERC "falls within its previously adopted schedule."

The panel's comments come as efforts to build two day-ahead markets in the West continue to ratchet up.

In recent months, the four U.S. senators from Washington and Oregon have urged the Bonneville Power Administration, one of the key Market+ players, to "act carefully and deliberately" before choosing a market. The agency has responded by reiterating its resistance to the CAISO Extended Day-Ahead Market's (EDAM) California-centric governance model and expressed support for SPP's market. BPA has delayed a decision until 2025, but it also plans to continue its funding in the second phase of the

From left: IMIP members Steve Wright and Elizabeth Moore listen to SPP's Antoine Lucas. | © *RTO Insider LLC*

SPP News

market's development. (See *'Leaning' Evident in BPA Response to NW Senators* and *BPA to Fund Phase 2 of Markets+, Agency Exec Says*.)

CAISO in June kicked off a West-wide Governance Pathways Initiative designed to shift the ISO's governance structure to an independent entity within the EDAM. Four workshops have highlighted the difficulty of designing a new Western "regional organization." (See related story *Comments on Western RO Stakeholder Plan Show Complexity of Effort*.)

While potential participants consider which market to join, some have already made that choice. NV Energy announced its intention to join EDAM, and two Black Hills Energy subsidiaries said they will leave SPP's Western Energy Imbalance Service for CAISO's Western Energy Imbalance Market. Black Hills participated in Markets+'s first phase and said it will pursue markets that "provide additional value."

For its part, SPP has increased its public outreach, stressing its ability to build and manage markets and transact energy over seams. It has also created *a spiffy website* dedicated to Markets+. (See *SPP's Experience with Seams Could Help Markets+*.)

"Organizations spanning the Pacific Northwest, Desert Southwest and Mountain West regions will weigh many factors in making decisions about participating in a regional electricity market," the IMIP said. "We trust they'll each make the ultimate choice that's best for their respective stakeholders."

The directors said SPP has approved a $150 million budget for the market's remaining development, "a fraction of a percent of the $25 billion in transactions that occur annually in Western wholesale trading markets today." They said Markets+'s governance and market design will offset upfront costs, with the RTO's experience operating other markets suggesting that Markets+ services will have a lower lifecycle cost than other alternatives.

According to *SPP*, BPA will be responsible for at least 17.4% of Phase 2 funding, second only to Powerex at 23.2%. Those percentages could increase should the Black Hills subsidiaries withdraw from further Markets+ development efforts.

MSC, IMIP Strengthen Relationship

The Markets+ State Committee, comprising Western regulators and one of the recipients of the IMIP's letter, has endorsed a resolution that provides greater cooperation between the commissioners and the IMIP.

The two bodies have agreed to participate in each other's meetings with allocated time on their corresponding agendas. They also agreed to host joint in-person or virtual meetings to address any issues during the market's development and operation.

Director Wright has indicated to the MSC that the IMIP will support the resolution.

The MSC meets monthly, while the IMIP generally meets during MPEC meetings. ■

SPP News

FERC Approves SPP Make-whole Payments Under Order 831

FERC has accepted SPP tariff revisions that allow make-whole payments for incremental energy costs affected by incremental energy offer caps under Order 831, regardless of the resource's reason for commitment.

The commission said in a Sept. 19 order that the revisions provide an opportunity for cost recovery, ensuring the resources have an opportunity to recover their incremental energy costs, and an incentive to provide accurate operating parameters and to follow dispatch instructions during Order 831 conditions (*ER24-2570*).

The revisions are effective Oct. 16.

FERC's Order 831 revised regulations to address incremental energy offer caps by requiring each commission-jurisdictional grid operator to: cap incremental energy offers at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer; and cap verified cost-based incremental energy offers at $2,000/MWh when calculating LMPs.

SPP uses energy offers between $1,000 and $2,000/MWh to set the LMP, but its Market Monitoring Unit must verify the offers in advance. The MMU verifies whether energy offers above $1,000/MWh reasonably reflect the resource's actual or expected costs prior to calculating LMPs.

SPP's control room | *SPP*

The Monitor told FERC it supported SPP's proposal, contending there are gaps in the make-whole payment construct that could impede generator owners from receiving full reimbursements under Order 831. It said the gaps could incentivize generators to reduce their financial risks, which could harm the market during extreme conditions. ■

— Tom Kleckner

SPP News

8th Circuit Denies Review of FERC Orders on SPP Attachment Z2

By Tom Kleckner

The 8th U.S. Circuit Court of Appeals on Sept. 16 denied review petitions by several SPP members over FERC's rejection of generators' rehearing requests seeking compensation under tariff Attachment Z2.

The court said it found "no error" in FERC's 2022 decisions and rejected the petitions filed by EDF Renewables, Enel Green Power, NextEra Energy Resources and Southern Power (*23-1520, et al.*).

At issue is Attachment Z2 of the SPP tariff, under which transmission upgrade sponsors receive credits from any upgrade users whose service could not be provided "but for" the upgrade. The attachment also requires the RTO to invoice the charges monthly and to make any adjustments within one year. Because of software problems, it took SPP eight years to implement the attachment before 2016, during which the RTO did not invoice for the upgrade charges.

FERC found in four separate orders that SPP had violated the filed-rate doctrine, its tariff and its contracts with three of the four generators. However, the commission declined to grant a remedy, citing the one-year limit on adjusting bills for customers. It also noted that SPP is a nonprofit entity with no independent funds to cover requested remedies.

The 8th Circuit concluded that although Attachment Z2 — and its requirement for upgrade credits — is part of the filed rate, FERC did not violate the filed-rate doctrine by not granting credits to the generators. The court said Attachment Z2 does not conflict with the billing requirements of the tariff and found that it "sets out the arrangement for sharing upgrade costs" but is silent on the timing of billing for upgrade charges.

"The commission thus had only one choice regarding [SPP's] customers: adhere to [the tariff] and the filed-rate doctrine," the court wrote.

The generators also contended that FERC failed to adequately explain whether its decision was based on a lack of authority or an exercise of equitable discretion, but the 8th Circuit disagreed, saying the commission "articulated a satisfactory explanation for its orders."

And "in any event, any error in failing to explain would be harmless here, because the agency was required by law to decline the requested remedies, and a remand would be unnecessary," it concluded.

A similar request by other SPP members was denied in 2023 by the D.C. Circuit Court of Appeals, which said it lacked jurisdiction to consider the utilities' filed-rate doctrine argument because they failed to exhaust it at the rehearing stage. (See *Appeals Court Denies Review of SPP Z2 Charges*.) ■

| Xcel Energy

Company Briefs

ENGIE Reaches 1.8 GW Battery Storage Capacity in US

ENGIE last week announced it has surpassed 1.8 GW of battery energy storage system (BESS) capacity in operation across the U.S.

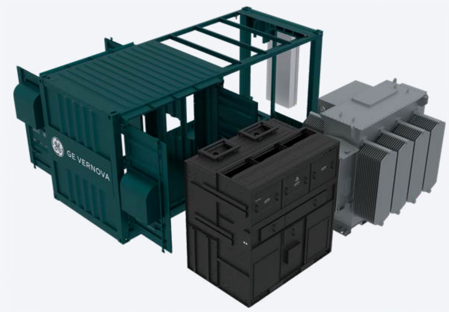
Since the beginning of 2024, ENGIE has added around 1 GW of new BESS capacity in North America.

More: *ENGIE*

GE Vernova Releases 2,000 V DC Utility-scale Inverter

GE Vernova last week introduced a new 2-kV DC utility-scale inverter.

The company said the Flexinverter 2000 Vdc will debut in a multi-megawatt solar park as part of a pilot installation in North



America, which is expected to become operational in the first quarter of 2025.

The product combines an inverter, medium-voltage transformer, and various configurable options, including GPS-enabled fault timestamping and revenue-grade metering. It features an air-cooled system. Its maximum power station efficiency at 40 degrees Celsius is rated at 98.4%, and its max inverter efficiency at 40 C is 99.1%.

More: *pv magazine*

Exowatt to Repurpose Tech to Deal with AI Power Demand

Exowatt last week unveiled its plan to develop a combination heat collector, heat battery and heat engine meant to provide emissions-free power for AI firms.

The company held an event at an RE+ industry conference and showed off its thermal battery that can hold energy for up to 24 hours. It also employs a Fresnel lens to focus and concentrate solar energy onto hot bricks, which is then extracted from the bricks with a Stirling engine.

Exowatt aims to "eventually" offer firm, clean electricity for 1 cent/kWh without subsidies.

More: *Canary Media*

Federal Briefs

DOE Loans $1.5B for Carbon Sequestration Fertilizer Project

The Department of Energy last week announced it has made a conditional commitment for a loan guarantee of up to $1.559 billion to Wabash Valley Resources (WVR) for a West Terre Haute fertilizer development.

WVR intends to pipe and inject 1.67 million tons of carbon dioxide annually a mile below the surface as part of its plan to produce "low-carbon-intensity" anhydrous ammonia fertilizer at a former coal gasification plant in Vigo County, Ind. WVR aims to produce 500,000 metric tons of anhydrous ammonia annually.

The $1.559 billion would be part of a total investment of $2.4 billion WVR would secure through private investment.

More: *Indiana Capital Chronicle*

DOE Picks NextEra for Solar Project on Nuclear Repository

The DOE last week announced it has chosen NextEra Energy Resources Development to design a 150-MW solar farm at a nuclear repository in New Mexico.

The project, which would also have 100 MW of storage, would be located on up to 1,800 acres at the Waste Isolation Pilot Plant.

More: *Axios*

NRC Approves Renewals for Turkey Point

Florida Power & Light Company last week said the Nuclear Regulatory Commission approved a license renewal for two of its Turkey Point nuclear plant units for another 20 years.

FPL said licenses for Units 3 and 4, both located south of Miami, have been extended through 2052 and 2053, respectively.

FPL said nuclear power accounts for 20% of its fuel mix and is the second-largest energy source in the state.

More: *Reuters*

NRC Says Palisades Needs More Inspecting, Repairs

The NRC last week said the Palisades Nuclear Power Plant will need more inspections, testing and repairs on its steam generator regarding the reopening of the plant.

The NRC said it is evaluating the data and assessing Holtec's plans to correct the conditions.

Earlier this year, the federal government announced a $1.5 billion conditional commitment to support the reopening of Palisades.

More: *WOOD*

State Briefs

CALIFORNIA

Poway City Council Approves Battery Storage Facility

The Poway City Council last week unanimously approved a land use designation change that will pave the way for a battery storage facility.

The Nighthawk battery storage facility drew heavy opposition from residents, who have recently dealt with storage facility fires.

More: *KNSD*

GEORGIA

PSC Approves Georgia Power's Biomass Plan

The Public Service Commission last week voted 4-1 to approve a Georgia Power plan to source more energy from burning wood known as "biomass," despite criticisms about its cost.

An independent evaluator found the three contracts Georgia Power was seeking approval for would cost customers two to three times more than other sources. While the regulators acknowledged the high cost, they said they were motivated to give an economic boost to rural parts of the state that rely on the timber industry.

The costs could add about $45 to the average customer's monthly bill by next year.

More: *The Atlanta Journal-Constitution*

LOUISIANA

PSC Awards APTIM Energy Efficiency Contract

The Public Service Commission last week voted unanimously to contract with APTIM as the administrator of its energy efficiency program through 2029 for $24.5 million.

Commissioners issued a request for proposals in May to build and oversee the state's new energy efficiency program. Nine companies responded, with three submitting formal proposals. APTIM was both the lowest bidder and the only company headquartered in Louisiana.

More: *Louisiana Illuminator*

MAINE

PUC Says CMP Can Skip Review of Acquisition Deal

The Public Utilities Commission last week voted 2-1 to allow Central Maine Power (CMP) to skip a state review of a $2.5 billion deal that puts its parent company, Avangrid, under full control of Spanish energy giant Iberdrola.

Chairman Phillip Bartlett II and Commissioner Patrick Scully followed a hearing examiner's report that said CMP's request for a waiver of state law calling for a review is warranted based on regulators' previous approval of the corporate structure. The utility argued that regulators already authorized Iberdrola's indirect ownership of CMP and Maine Natural Gas in 2008 when Iberdrola acquired Energy East Corp., a predecessor of Avangrid.

Iberdrola will acquire the remaining 18.4% of shares of Avangrid it does not currently own.

More: *Portland Press Herald*

Trenton Extends Solar Moratorium

Trenton last week extended its moratorium on medium- and large-scale solar development by 180 days.

The current moratorium expires Oct. 5 but will be extended another 180 days or until an amendment dealing with solar developments in the town is adopted.

More: *Bar Harbor Story*

NEVADA

PUC Denies NV Energy's Proposed Rate Change

The Public Utilities Commission last week denied a NV Energy request to raise its Northern Nevada customers' rates by 175%.

The request would have increased Northern Nevada's basic service charge from $16.50 to $45.30 per month and made it the highest in the U.S. Instead, the PUC approved a $2 per month increase that will take effect in October.

In its draft order, the commission stated the proposed increase was "inordinately large and not in the public interest."

More: *The Nevada Independent*

NORTH CAROLINA

Appeals Court Upholds Duke Energy's Lower Net Metering Rates

The Court of Appeals in North Carolina last week upheld Duke Energy's reduced net metering payments.

NC WARN, Environmental Working Group and others opposed to an earlier compromise made between Duke and solar installers argued the Utilities Commission adopted it without conducting their own analysis of the costs and benefits of net metering, a requirement of a 2017 statute.

While Judge Hunter Murphy said commission "erred in concluding that it was not required to perform an investigation of the costs and benefits of customer-sited generation," "the record reveals the commission performed such an investigation when it opened an investigation docket in response to [Duke's] proposed revised net energy metering rates." He went on to say the commission "properly considered the evidence before it and made appropriate findings of fact and conclusions of law."

More: *Energy News Network*

TEXAS

Pipeline Fire Burns Near Houston After Vehicle Strikes Valve

A towering flame gradually subsided last week in the aftermath of a massive pipeline explosion after a vehicle drove through a fence and struck an above-ground valve, officials said.

Firefighters initially were dispatched at 9:55 a.m. on Sept. 16 for an explosion at a valve station in Deer Park. Operators shut off the flow of natural gas liquids in the pipeline, but so much remained that firefighters could do nothing but watch. The fire eventually went out on Thursday. Harris County Judge Lina Hidalgo said 20 miles of pipeline between the two closed valves had to burn off before the fire would stop. An evacuation area included nearly 1,000 homes, and initial shelter orders included schools.

Deer Park officials said police and local FBI agents found no preliminary reports that would suggest a coordinated or "terrorist" attack, and it appeared to be an isolated incident.

More: *The Associated Press*; *The Associated Press*; *The Associated Press*