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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: FERC Chair Richard Glick receives a standing ovation at the close of his final commission meeting. | *FERC*

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Counterflow

By Steve Huntoon

A Few of My Favorite Things

By Steve Huntoon

What makes us happy? In this holiday season I thought I would take a break from our industry and throw out a few points of joy for me (besides family and friends). And if you want to nominate some, please email me at huntoon@comcast.net for a potential sequel.

1. No Surrender festival. Crazy Springsteen sing-along and play-along with 4,000 delirious Spaniards. https://www.youtube.com/watch?v=alorNxGo0FM
2. The final scene of "Casablanca's". The triumph of good over evil, the sacrifice of love for the cause, the friendship you didn't see coming, and written on the fly during war. In two parts: https://www.youtube.com/watch?v=rEWaqUVac3M and https://www.youtube.com/watch?v=5kiNJcDG4E0.
3. "The Joke" by Brandi Carlile. It gets me every time. https://www.youtube.com/watch?v=5r6A2NexF88
4. Anthony Bourdain. I'm still not sure what it was he had, but he had it in spades.
5. "Vacation" by the Go-Go's. Faux surfing starts at 1:15. https://www.youtube.com/watch?v=2RHTiXvELNg
6. "Star Trek: The Next Generation." Of course the original series was great, but almost every episode of the Picard series is too.
7. Frosty the inflatable. Every year our 8-foot Frosty goes up on our second-floor deck happily welcoming everyone. There's just something about that.
8. "The Rocky Horror Picture Show." How did Richard O'Brien create all this 47 years ago? My favorite song, "Science Fiction/Double Feature" (not "Time Warp"). https://www.youtube.com/watch?v=GKhPVHood-rU
9. "I'd Do Anything for Love" (But I Won't Do That). Mr. Loaf may have learned a little about drama from his cameo for Mr. O'Brien as a leather-clad biker. https://www.youtube.com/watch?v=9X_ViIPA-Gc
10. The beach. Any beach.

The best of the holidays to you and yours! ■

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Stakeholder Soapbox

A Transmission Planning Resolution Emerges

By Devin Hartman and Kent Chandler

Devin Hartman, R Street Institute | *R Street Institute*

For more than a year, FERC, state authorities and industry stakeholders have agonized over the performance of transmission planning. The most notable forums include the Joint Federal-State Task Force on Electric Transmission and FERC's October 2022 technical conference.[1,2] The only reform action to date has been a Notice of Proposed Rulemaking on regional transmission planning issued by FERC last April, with a final rule in sight for early-to-mid 2023.[3]

These processes have revealed troubling flaws in transmission federalism. Moving forward, three principles should guide transmission planning reform:

1. *Durability*. Reforms must be legally and politically robust to secure a stable regulatory climate.
2. *Quality governance*. Local and regional transmission planning are co-dependent, meaning they require synchronization between state and federal regulators with clear roles and responsibilities for each. Proper transmission planning also requires independent administration and monitoring.
3. *Sound economics*. Planning should be proactive, incorporate all technological solutions, and maximize net benefits to consumers. Procurement should be competitively bid wherever possible and regulatory scrutiny should fill in gaps where competition is unworkable.

Current transmission planning does not embody these principles. The consequences are higher-than-necessary costs, stifled innovation, diminished reliability and prolific controversy. FERC Commissioner Mark Christie recently observed that transmission capital expenses have nearly tripled between 2012 and 2020.[4] Feeling this pain, dozens of consumer groups have called for better governance, planning and competitive procurement.[5]

Repairing Current Frameworks

The economic disappointment and extensive controversies surrounding transmission

Kentucky Public Service Commission Chair Kent Chandler testifies at a FERC technical conference on transmission planning and cost management in October as Commissioner Mark Christie listens. | *FERC*

development should come as no surprise: They directly reflect the institutions and policies underlying transmission planning and procurement. FERC Orders 890 and 1000 have good bones, but framework adjustments along with fixing key implementation flaws are paramount. For example, the same rules ostensibly exist regardless of regional transmission organization (RTO) membership, but two sets exist in practice — one in RTO regions and another outside them — creating untenable governance issues.

The current regional transmission framework is reactive, miscounts transmission benefits, excludes some technologies from consideration and plans economic and reliability projects in artificial silos. Astoundingly, a large proportion of transmission development is neither subject to competitive bidding nor economic regulation. Competitive exemptions are too frequent in RTO footprints, while competition is non-existent outside RTOs.

Where competition is absent, gaps in regulatory oversight remain pervasive. FERC's formula rates for transmission, coupled with the presumption of prudence, is not economic regulation. Meanwhile, not many states have full authority to approve or review transmission projects, and even fewer state commissions play a meaningful role in the planning of transmission facilities.[6] Projects in the 100-230 kilovolt (kV) range, those creatively dubbed "reliability need," or those within a single transmission zone, regardless of cost allocation, often fall between the cracks.

In Order 1000, FERC declined to remove a federal right of first refusal for local transmission, out of consideration for incumbent utilities' retail "service obligation." However, since Order 1000, billions of dollars of local transmission have been built by affiliates of incumbents, without having a service obligation themselves.[7] These projects are exempt from competition. State utility commissions have little-to-no jurisdiction over them. And their costs are often allocated across state lines.

Further, it is hardly fair to consider transmission between 100 and 230 kV "local" given the increasingly regional nature of those facilities. Between February 2020 and July 2022, the Kentucky Siting Board approved certificates for 20 merchant solar facilities, between 40 and 250 MW, with an average size of more than 100 MW.[8] All of the projects propose to build or connect to transmission below 200 kV, and only one-fifth of the projects are being

Stakeholder Soapbox

built to provide power to Kentucky utilities, while the rest will serve customers across the Tennessee Valley Authority, MISO and PJM footprints.

At above-market rates of return, it is no surprise that incumbent utilities have prioritized building out transmission where competition and regulatory oversight are virtually absent. In doing so, they typically pursue inefficient small projects in lieu of more efficient technologies and subvert the planning of more efficient alternatives at the regional level.[9] In some regions, the majority of transmission projects skirt competition and robust regulatory review, and the number is growing.[10]

Repairing all this requires governance and economic reforms to work in tandem, augmented by stakeholder buy-in. Three reform priorities are:

1. *Improve the Order 890 and 1000 frameworks.* Equalize the application of Orders 890 and 1000 across RTO and non-RTO regions. All regional transmission should be independently planned. RTOs provide this function, but accomplishing this objective outside RTOs would require an independent transmission planner. Regional transmission planning must account for public policy effects on generation, including anticipated retirements based on plant economics, and not wait for deactivation notices to be submitted.
2. *Make regional transmission planning proactive and holistic with enhanced competition.* Planning should reflect the multi-decade nature of the investment, incorporate commercially available technologies, and account for the full suite of economic and reliability benefits simultaneously, not in silos. Minimizing competitive exemptions is crucial, with options including stricter "reliability need" exemptions and lowering the voltage exemption threshold to 100 kV to comport with the standard definition of the bulk power system.[11] This would clarify for states the scrutiny that some projects undergo.
3. *Ensure economic oversight where competition is unworkable.* Utility projects exempt from competition must face economic scrutiny from regulators, which warrants reexamining the policy of unconditional formula rate treatment under a presumption of prudence. Need and prudence are impossible to judge without information. State regulators note that an independent transmission monitor (ITM) could furnish such information and help close the regulatory gap with local transmission projects.[12] It could also help ensure Order 890 compliance.

Reform Agenda

Transmission reforms are as entangled as the bulk power system. Yet many reforms will be pursued through disparate procedural vehicles, which elevates coordination risk.

FERC's first bite at the apple is its forthcoming final rule on transmission reform. The winning formula is for FERC to jettison the anti-competitive provisions of its proposed rule while refining the good ones, including the longer-term planning horizon, what advanced technologies to include in planning, holistic benefits accounting and breaking down silos between "economic" and "reliability" project planning.[13]

FERC will need to pursue the remaining reform agenda through separate proceedings. The October technical conference established a record upon which to prioritize governance improvements, including the role of independent monitoring and planning, as well as pathways to expand competition and close the regulatory gap for projects where competition is unworkable. This could spin off into any number of dockets. The trick will be connecting the dots. ■

Devin Hartman is director of energy and environmental policy for the R Street Institute.

Kent Chandler is the chairman of the Kentucky Public Service Commission.

[1] https://www.ferc.gov/TFSOET.

[2] https://www.ferc.gov/news-events/events/technical-conference-transmission-planning-and-cost-management-10062022.

[3] https://www.ferc.gov/news-events/news/ferc-issues-transmission-nopr-addressing-planning-cost-allocation.

[4] https://www.marylandmatters.org/2022/11/29/as-utilities-spend-billions-on-transmission-support-builds-for-independent-monitoring.

[5] https://electricitytransmissioncompetitioncoalition.org.

[6] https://www.rtoinsider.com/articles/30933-ferc-tech-conference-highlights-regulatory-gaps-tx-oversight.

[7] See, e.g., https://www.fitchratings.com/research/corporate-finance/fitch-rates-aep-transmission-co-llc-senior-notes-a-07-06-2022.

[8] https://psc.ky.gov/Home/EGTSB.

[9] https://www.rstreet.org/wp-content/uploads/2022/05/RSTREET257.pdf.

[10] https://www.utilitydive.com/news/ferc-naruc-task-force-independent-monitor-itm/636677.

[11] https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf.

[12] https://www.utilitydive.com/news/ferc-naruc-task-force-independent-monitor-itm/636677.

[13] https://www.rstreet.org/2022/08/22/the-good-the-bad-and-the-winning-formula-for-fercs-regional-transmission-reform-proposal.

FERC/Federal News

Glick Bids Farewell to FERC

With End of Year Approaching, 'not a Path Forward' for 2nd Term

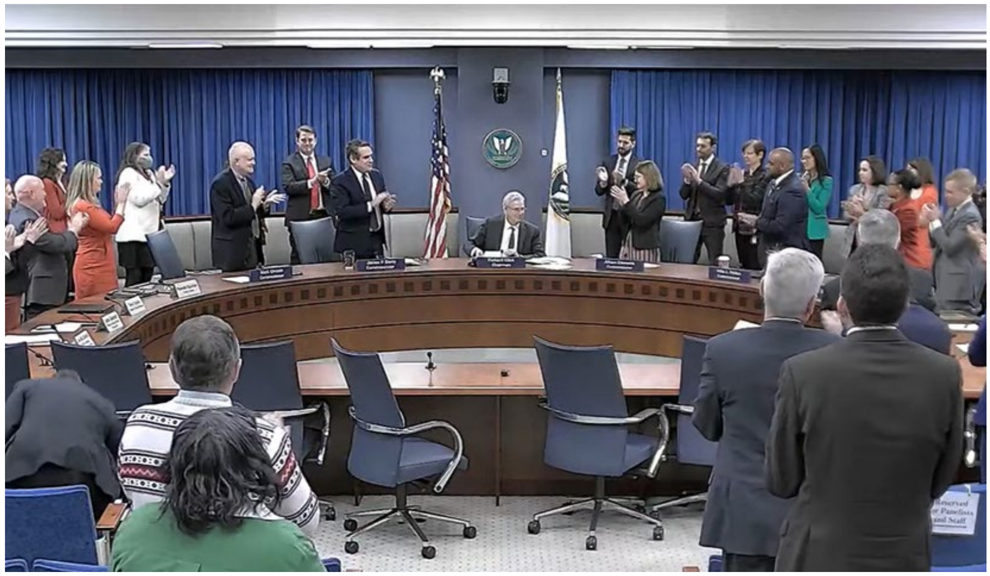
By Michael Brooks

WASHINGTON — FERC Chair Richard Glick said Thursday that he will leave the commission when the 117th Congress adjourns, likely by the end of the year, ending five years as a federal energy regulator.

President Biden nominated Glick for a second term in May, but Sen. Joe Manchin (D-W. Va.), chair of the Senate Energy and Natural Resources Committee, has refused to hold a confirmation hearing for him. (See *Glick's FERC Tenure in Peril as Manchin Balks at Renomination Hearing*.)

Glick's term ended June 30, but if they are not nominated for another term, FERC commissioners are allowed to continue serving past the end of their current terms until a replacement is confirmed or until the current Congress adjourns *sine die*. (Congress' adjournment is typically before the end of the calendar year, though it could be in session until noon on Jan. 3.)

Given how late it is in the year and how long the confirmation process takes in the Senate, "I think it's pretty clear there's not a path forward anymore" for his nomination, Glick said at the commission's last open meeting of the year.



FERC Chair Richard Glick receives a standing ovation at the close of his final commission meeting. | *FERC*

Although Glick remains the nominee until the end of Congress, he told reporters after the meeting that he has already declined to be nominated again next year.

"I'm still a candidate out there, but just given the timetable and the time it takes to move a nominee forward, I don't really foresee" being confirmed this year, Glick said in a press conference after the meeting. "I have notified [the White House] that I'm not interested in coming back, in large part because I know this [nomination] process pretty well. Even under the best of circumstances, I know it would take a number of months. I can't do that to my family; I can't do that to myself, for that matter."

And unless something unexpected happens, Glick added, "Sen. Manchin is still going to be chair of the Energy Committee. I don't know why things might be different next year versus this year, so I think it's better that they [the administration] move on."

Manchin was angered earlier this year by the commission's proposal to consider greenhouse gas emissions in natural gas infrastructure certificates.

Glick did not participate in several orders that were part of the meeting's consent agenda: two that involved MISO (ER22-477-002 and ER22-995-001, both of which had not been published as of press time), and one that involved utilities in the WestConnect transmission planning region (*ER22-1105*). Last month he did not participate in an order that involved PJM (*ER22-2110*).

Glick told reporters he recused himself from these orders because once it became clear to him that he would not be confirmed, he had expressed interest in an available job. Though

FERC Chair Richard Glick jokingly refers to his "binder of grievances." | *FERC*

FERC/Federal News

he did not end up getting the job — nor had he even formally applied — under FERC's ethics rules, "you not only have to recuse when you're negotiating ... you also have to recuse afterward during a 'cooling-off' period," he said.

When asked if he had any work lined up for after he leaves, Glick joked, "Not unless you know something."

"You know, people say this all the time: 'I'm leaving the job to spend more time with my family!'" he said during the meeting, citing the demands of the commission that often require working late Fridays and weekends and taking late-night phone calls. "But that's what I intend to do, and I really look forward to it."

Fierce, but (Mostly) Collegial, Debates

Glick was nominated by President Donald Trump and joined the commission in November 2017. Biden, upon becoming president in 2021, named Glick chair to replace Republican Commissioner James Danly.

His tenure at the commission — both as a commissioner in the Democratic minority, and as chair with a majority — was marked by a fierce divide along party lines. Glick wrote scathing dissents to the Republican majority's decisions in many high-profile dockets and butted heads with Chairman Neil Chatterjee and Commissioner Bernard McNamee. He was then on the receiving end of many equally scathing dissents from Danly — sometimes joined by fellow Republican Commissioner Mark Christie — when he was chair.

Chatterjee and Glick did find common ground, however, on several notable issues, such as Orders 841 and 2222 — which directed RTOs and ISOs to open their markets to energy storage and distributed energy resource aggregations, respectively. And since leaving the commission, Chatterjee has often called Glick his friend. Though he frequently issues separate concurrences noting his concerns, Christie has also sided with the Democratic majority often.

In contrast, Glick and Danly's debates have not just played out in concurrences and dissents, but also at open meetings, normally tightly scripted affairs. Glick once compared Danly to a Chicken Little-like Paul Revere; during the same meeting, Danly said Glick was being snide. (See *FERC Rejection of Weymouth Rehearing Leads to More Barbs*.)

At the close of Thursday's meeting, both commissioners somewhat sheepishly acknowledged the tension.

"And now we come to Commissioner Danly," Glick said after praising his other three colleagues. "It's an understatement to say we've had our difference of opinions. And we've certainly said some harsh things about each other. ... But we've kept our lines of communications open. In our conversations, we've kept things civil. ... And I think it's very important on a going-forward basis that even when there's differences in opinion ... it's important to keep those lines of communications open and figure out where you can work together and how you can work together."

Danly, who served as FERC general counsel before he became a commissioner, told Glick that he "breathed a massive sigh of relief and gratitude when you appointed Matt [Christiansen] general counsel. You know, when I was GC, he created a great deal of work for me with all the dissents, and I think the score is almost settled at this point."

He also affirmed "that it is true that we have wrangled a lot and disagreed a lot. ... It has been more than five years that we have been fighting over substance, and we both have the scars to prove that. ...

"When you read the press accounts — '*Glick, Danly Spar on...*' — sure, we are, but in reality we have quite a bit of collegiality," Danly said. He also praised Glick's graciousness in helping him with "problems or resource needs" and for being accommodating given the "vast number of orders we have to push through."

Glick concluded his remarks at the meeting by expressing gratitude for "five exciting and engaging years."

"I can honestly say that we have not had one boring day at the commission. Not at all boring. These days, it's inextricably linked to ... the transition that's underway to the way we produce, the way we consume and the way we transport energy. It's, from a technological standpoint, amazing. The speed at which we're moving forward is amazing. And from a societal perspective — whether it be from an economic perspective to the United States, or just in terms of the environment — it's just tremendous." ■

FERC Commissioner James Danly, who famously clashed with Chairman Richard Glick over the past five years, praised the chairman for being "unfailingly gracious." | *FERC*

FERC/Federal News

Will Glick's Departure Mean More On-time FERC Meetings?

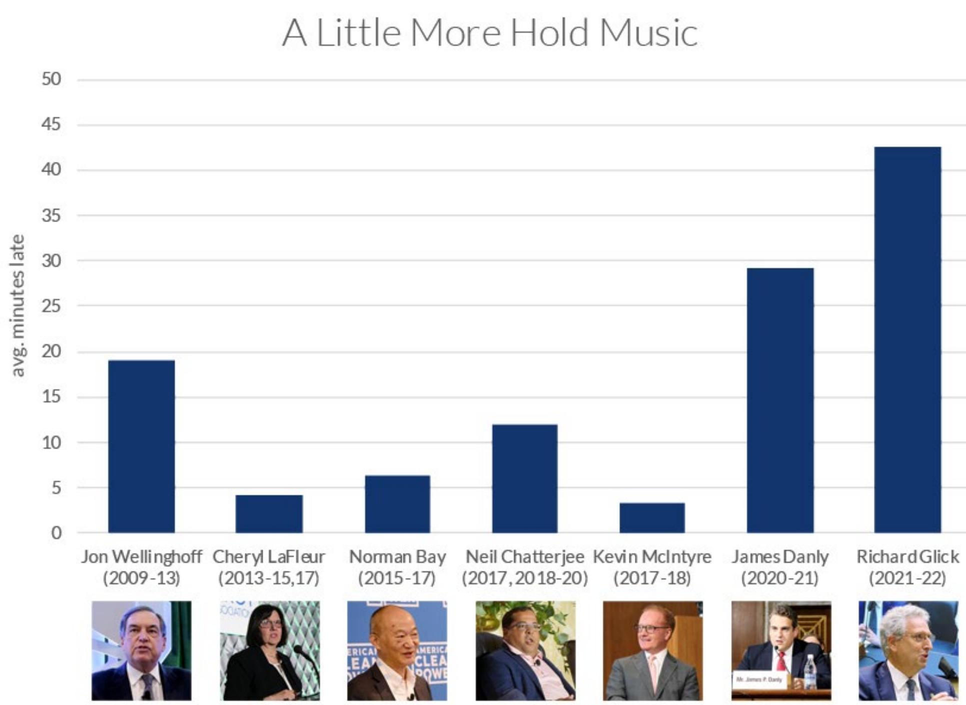
Last-minute Negotiations Leave FERC Watchers Waiting

By Rich Heidorn Jr.

There's a ritual most third Thursdays of the month among the FERC watchers on #energytwitter.

When 10 a.m. comes and goes without the commissioners taking their seats around their semicircular dais, the stakeholders who attend the monthly open meetings in person continue their schmoozing. But for those watching via the commission's webcast, it provokes critiques of the hold music and sarcastic comments about how the commission is late — *again.*

FERC meetings have often started after the advertised 10 a.m., but they reached new tardiness levels during the two years of Richard Glick's chairmanship, inspiring one civic-minded FERC watcher to launch a Twitter account earlier this year, *FERCStartTime*. ("Solely dedicated to announcing the ACTUAL start time of FERC's monthly open meeting. I listen to the looped hold music so you don't have to.")



FERC's open meetings have begun on average 42 minutes late under Chair Richard Glick, far higher than any other chair since 2010. | © *RTO Insider LLC*

According to an *RTO Insider* analysis of FERC meetings since January 2010, FERC meetings began an average of almost 42 minutes late during the two years of Glick's chairmanship — by far the longest of the seven FERC chairs during that period. Glick likely chaired his final meeting Thursday after failing to win a hearing on his renomination. It started 72 minutes late. (See related story *Glick Bids Farewell to FERC*.)

Former Chairs Norman Bay, Cheryl LaFleur and Kevin McIntyre were relatively prompt, starting their meetings on average within six minutes or less of the scheduled start. Neil Chatterjee, Jon Wellinghoff and James Danly were on average 12 to 29 minutes late.

Glick and Danly also hold the top spots when ranked by median tardiness (33 and 30 minutes, respectively). Wellinghoff's tardiness drops from an average of 18.9 minutes to a median of five, while Bay's drops from an average of 6.3 to a median of one and Chatterjee from an average of 11.8 to a median of eight.

RTO Insider's analysis is based on transcripts of 133 meetings since January 2010. Seven meetings were canceled during that period, one because of the COVID-19 pandemic in March 2020 and six because of a lack of quorum in 2017. Transcripts were not posted for three meetings and could not be located. The analysis reflected rescheduled start times on a few occasions when meetings were delayed because of inclement weather and protester disruptions.

In interviews, former FERC staffers cited increased partisanship, the challenges of remote work during the pandemic, and the increasing public profile of the commission and the issues facing it for the increased delays.

Wellinghoff said "a chairman should make every reasonable effort to start meetings on time," and lamented that one nearly three-hour delay had inflated his average. He said he could not recall the reason for the delay.

Glick, Bay and LaFleur declined to comment last week. Danly did not respond to requests for comment. McIntyre died in 2019.

Chatterjee, now a senior adviser at law firm Hogan Lovells, said the delays have increased in part because the meetings "have become really scripted affairs."

"This is a conversation that I've actually had with a number of former chairs and commissioners that in the 80s, and 90s, in particular, and even in the early 2000s, the open meetings were kind of freewheeling debates," Chatterjee said.

"What is happening now is — quite frankly, for strategic purposes — dissenting commissioners are withholding their separate opinions until the very last moment, and then … the chair and the majority has to then amend the order to account for some of the arguments being made in the dissenting opinions, and then amend their statements."

Glick 'Embarrassed'

At a press conference following the commission's May 19 meeting, which started only 19 minutes late, Glick acknowledged he's "sometimes … embarrassed when we don't start on time."

"I would love to sit here and tell you that [the May 19 start] means that we're always going to be on time or at least close to on time," said Glick. "But every commission meeting is different. Every set of orders that we have to consider are different. Sometimes there's late negotiations between offices; [sometimes] we have difficult decisions we have to talk through with other offices. … The items that were on

FERC/Federal News

the agenda today [lent] themselves towards enabling us to start earlier."

FERCStartTime, which began tracking the meetings in May, now has more than 150 followers, a who's who of #energytwitter, including LaFleur; former Commissioner Phil Moeller; Glick's chief of staff, Pamela Quinlan; analyst Christine Tezak; Harvard Law School's Ari Peskoe; former Montana Public Service Commissioner Travis Kavulla; and Todd Snitchler, CEO of the Electric Power Supply Association.

It is "the most passive aggressive account on all of #energytwitter," tweeted Joe Daniel, a manager in RMI's Carbon-Free Electricity Practice.

What Goes On

So what's happening on the 11th floor of FERC headquarters while we're listening to "Man in the Mirror" for the third time?

Jeffrey Dennis, who recently left Advanced Energy Economy for the Department of Energy's Grid Deployment Office, saw the process first-hand between 2010 and 2015, when he headed the Office of Policy Development and served as an aide to Commissioner John Norris.

"I think that what's going on is that there are continued efforts to try to reach compromises [and] ensure that the language that the commission is voting on is ultimately what folks have agreed to — whatever compromises they've made — or that they're giving the commissioners sufficient time to know what's [included in] a vote … so that when they make their comments at the open meeting, they're well informed, and they're not making comments on something that perhaps was struck out of an order," Dennis said.

"It did happen less often [in the past]. And I think that speaks to [the fact that] we certainly are seeing more separate statements, more orders that don't have unanimity than we did … 15 years ago. That in some ways is a recognition of how much more difficult and controversial a lot of the issues the commission has before it are and the work it takes really to tackle these big issues," Dennis continued. "The issues before FERC were always significant, but they are increasingly in the public eye. There does seem to be a bit more partisanship than there was before; I don't want to [say on] every issue, but many."

Grid Strategies President Rob Gramlich, who served as economic adviser to FERC Chair Pat Wood III from 2001 to 2005, said the remote work caused by the COVID-19 pandemic has contributed to the delays.

"It was always the case [that] we were negotiating orders right up to the last minute, so that's not new," he said. "You can get a lot more done when you're physically there in person than when you're all working off site. So I'm going to give the commission a pass for the last couple of years on that, because no previous commission ever had to negotiate final orders across five different offices and multiple staff offices from their homes all over the place."

Larry Gasteiger, who worked 19 years at the commission (1997-2016) — including stints as legal adviser to Chair Joseph T. Kelliher and chief of staff to Chair Bay — said he sees a lack of discipline in the increasingly late starts.

"There was a lot of emphasis put on trying to resolve issues well in advance of the commission meeting so that we could essentially put it to bed … if not the evening before, certainly the morning of the commission meeting," said Gasteiger, now executive director of the trade group WIRES. "And it's a lot of work. I don't want to suggest that it's easy to accomplish that. It's not. It's really hard.

"Frankly, though, it does depend on the cooperation of all of the commissioners. I think we were lucky in the sense that the commissioners, at the time I was there, were really focused on trying to get the items ready so that the commission meeting could start on time," he added. "It shows a level of respect for all of the … stakeholders who are interested in watching the meetings. … Once it starts to run into one or two hours later, that's a lot of people sitting around waiting for commission meeting to start."

Gasteiger acknowledged the commission's tardiness has become a running joke on Twitter.

"But the joke's getting kind of tired, frankly. And I just think the commission needs to get its act together. And I don't point to the chairman only on this. All the commissioners need to be working on getting the meeting started promptly and on time. It can be done. It was done regularly for many, many years."

It remains to be seen whether a new chairman will have any more success at on-time meetings. But one thing is certain: Since FERC moved its webcasts to YouTube, remote viewers can no longer hear playlists compiled by commissioners or commission offices while waiting for the meetings to start because of royalty issues.

"YouTube is very strict on that," said FERC spokeswoman Mary O'Driscoll. "You have to be in the commission meeting room to hear the hold music." ■

FERC/Federal News

Manchin Permitting Bill Falls Short in Senate

By Rich Heidorn Jr.

The Senate on Thursday night rejected Sen. Joe Manchin's (D-W.Va.) bid to tag his controversial permitting bill to the National Defense Authorization Act (NDAA).

Sen. Roger Marshall (R-Kan.) speaks against Manchin's amendment. | *C-SPAN*

Needing 60 votes to append his bill to the NDAA, Manchin won only a 47-47 tie, despite an endorsement Thursday morning from President Biden, who said it would "cut Americans' energy bills, promote U.S. energy security, and boost our ability to get energy projects built and connected to the grid."

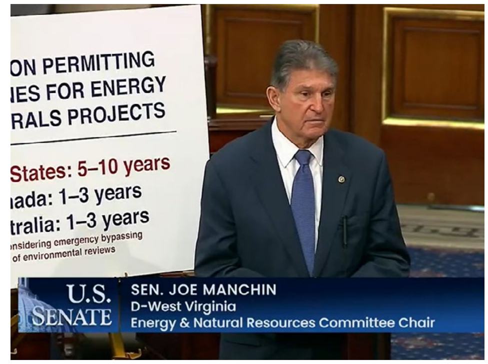
The *Building American Energy Security Act of 2022*, which would accelerate permitting of energy and mineral infrastructure projects, faced opposition from Democrats — who saw it as a concession to the oil and gas industry — and Republicans upset with Manchin's vote for the Inflation Reduction Act. (See *Manchin Presses Permitting Proposal Excluded from Defense Bill*.)

It also faced opposition from state regulators upset by provisions increasing federal transmission siting authority. "States are not the problem," the National Association of Regulatory Utility Commissioners said in a *letter*. "Rather, existing federal law and policies have been the biggest barrier to infrastructure rollout."

Americans for a Clean Energy Grid, the American Council on Renewable Energy, the International Brotherhood of Electrical Workers, the Solar Energy Industries Association and Third Way issued a *statement* supporting the transmission provisions.

"A comprehensive approach to advancing new transmission investment is long overdue and urgently needed," the groups said. "While it is not comprehensive, we believe the transmission portion of the Building American Energy Security Act of 2022, as updated last week, will make incremental, yet meaningful, progress."

Manchin gave an impassioned 11-minute *speech* on the Senate floor before the vote. Afterward, he issued a statement putting the blame for the bill's failure on Republicans.



Sen. Joe Manchin (D-W.Va.) argues for passage of his permitting legislation. | *C-SPAN*

"Once again, Mitch McConnell and Republican leadership have put their own political agenda above the needs of the American people," he said.

"As frustrating as the political games of Washington are, I will not give up," he added.

Among the "yes" *votes* were five Republicans. Nine Democrats and Sen. Bernie Sanders (I-Vt.) voted "no." Six Republicans abstained.

The $858 billion NDAA passed later Thursday evening on an 83-11 vote. ■

Senate votes on Manchin permitting bill. | *C-SPAN*

FERC/Federal News

FERC Orders NERC Review on Physical Security

Acts in Response to Attack on Duke Substations

By Rich Heidorn Jr.

Reacting to recent sabotage events, FERC ordered NERC on Thursday to report within 120 days on the effectiveness of its existing physical security reliability standards and determine whether improvements are needed (RD23-2).

The commission acted in response to the Dec. 3 gunfire attack on two Duke Energy substations in North Carolina, which left 45,000 customers without power for as long as four days. Shots also were fired near Duke's Wateree Hydro Station in Ridgeway, S.C., later in the month. (See *Duke Completes Power Restoration After NC Substation Attack*.)

"In light of the increasing number of recent reports of physical attacks on our nation's infrastructure, it is important that we fully and clearly review the effectiveness of our existing physical security standard to determine whether additional improvements are necessary to safeguard the bulk power system," FERC Chairman Richard Glick said.

FERC's existing physical security reliability standard (CIP-014-3), approved in 2014, requires transmission owners to perform periodic risk assessments to identify transmission stations and substations whose loss or damage could result in instability, uncontrolled separation or cascading outages. The standard also applies to primary control centers overseeing such facilities.

Transmission owners and operators must evaluate potential vulnerabilities of a physical attack to each of those assets and develop and implement physical security plans to protect them. It requires TOs to have an unaffiliated third party verify the risk assessments and security plans.

The commission directed NERC to assess the effectiveness of the current standard in light of the recent attacks, including evaluations of the adequacy of the applicability criteria and required risk assessments. NERC also must determine whether a minimum level of physical security protections should be required for all BPS transmission stations, substations and primary control centers.

Glick said the North Carolina attacks, and news reports of incidents in the Northwest and elsewhere, "reminds us that we need to take physical security into account just like cybersecurity."

Mark Hegerle, FERC Office of Electric Reliability | *FERC*

"We don't want to get out in front of the FBI [which is investigating the North Carolina incident], and we don't know exactly what [the attackers'] motives were or what or what actually happened. … But in the meantime, I think it's a good idea … to reassess our existing security standards, and whether changes need to be made."

Glick also noted that some incidents occur at electric facilities below the bulk power system, which are subject to state regulation. "So we need to work with our state colleagues as well to make sure that we're prepared; they're prepared; and we all do as much as we can to make sure that the grid is as secure as possible."

Commissioner Mark Christie said common distribution transformers are "vulnerable to a drunk with a gun and an attitude and … we have a lot of incidents of that. [The loss of a transformer] knocks out a block or two — a substation, several tens of thousands of people."

Christie said he expects NERC to recommend upgrades to the standard, such as requiring high-definition cameras at substations. "That's going to be really costly," he said, adding that he hoped the Department of Energy will provide support from the $15 billion in grid resilience funding from the Infrastructure Investment and Jobs Act.

"I hope this does not flow through to ratepayers," he said. ■

FERC/Federal News

FERC, NERC See Progress on Winter Weatherization

Additional NERC Rules 'a Heavy Lift'

By Rich Heidorn Jr.

FERC Chairman Richard Glick said Thursday that regulators and industry have made "remarkable" progress on recommendations in response to the February 2021 winter storm but that he isn't ready to declare "Mission Accomplished."

FERC and NERC staffers told the commission during a *presentation* at the monthly open meeting that progress has been made on all 28 recommendations in the FERC-NERC *report* issued in November 2021, thanks to efforts by the ERO, Texas Railroad Commission (RRC), North American Energy Standards Board (NAESB) and National Association of Regulatory Utility Commissioners (NARUC), as well as ERCOT, MISO and SPP.

Among the responses cited by David Huff, of FERC's Office of Electric Reliability, and Kiel Lyons, of NERC, were:

- ERCOT's inclusion of the February 2021 extreme winter weather conditions in calculating its base peak demand forecast for its 2022/23 Winter Seasonal Assessment; SPP incorporating a 90-10 load forecast and including limited fuel supply scenarios in its 2022/23 Winter Assessment; and MISO's move to a seasonal capacity construct in winter 2023/24.
- the Public Utility Commission of Texas' work with the RRC to adopt an electric supply chain map of critical interdependent natural gas and electric infrastructure, which identify types of natural gas infrastructure to prioritize for protection from firm load sheds.
- the PUC's actions advancing new transmission beyond the Texas Interconnection's current 1,220 MW of asynchronous DC ties to SPP (820 MW) and Mexico (400 MW). Southern Cross Transmission would provide a 2,000-MW link between the Texas Interconnection and the SERC Reliability region, while Grid United's Pecos West project would add a 1,500-MW HVDC line between ERCOT's West Texas region and El Paso in WECC territory (Project 53758). (See *ERCOT Board Gives Southern Cross Project a Boost*.) The FERC-NERC report said such links would increase the region's import capacity during emergencies and improve its black start capabilities.

Kiel Lyons, NERC, and David Huff, FERC Office of Electric Reliability, brief FERC commissioners on the status of recommendations the agencies made to improve winter readiness following the 2021 winter storm. | *FERC*

- NERC's September 2022 cold weather preparations *alert* and the ERO's cold weather preparedness webinars and workshops, and the incorporation of more comprehensive extreme weather scenarios and energy assessments in NERC's 2022/23 Winter Reliability Assessment. NERC's Reliability and Security Technical Committee will hold a summit Jan. 31-Feb. 2 on the progress made toward implementing the recommendations.

Fourth Winter Event in 10 Years

The storm marked the largest firm load shed event in U.S. history, at 23,418 MW, and was the fourth event in 10 years in which reliability was jeopardized by unplanned generating unit outages in cold weather.

NERC initiated *Project 2019-06* in response to a January 2018 cold weather event, when below-average temperatures resulted in 183 generating units in SPP, MISO, the Tennessee Valley Authority and SERC experiencing either an outage or a failure to start over a five-day period.

The rules — which require generator owners (GOs) to protect their units from freezing, and transmission operators (TOPs) and balancing authorities to revise their emergency operating plans — were approved by FERC in August 2021, several months after the February 2021 storm. (See *FERC Approves Cold Weather Standards*.) They don't become effective until April 1, 2023 — too late for this winter.

Glick recalled that he and NERC CEO Jim Robb vowed that the findings on the storm would result in significant change and not "gather dust" like prior reports. (See *FERC, NERC Release Final Texas Storm Report*.)

"I think it's remarkable when you think about the short time period [since the report] that we've made progress on all 28 recommendations," Glick said. "Now, I want to make it clear: We're not hanging the 'Mission Accomplished' banner. There's still a lot more that needs to be done here ... before we can feel more comfortable about where we stand in terms of Texas, but also elsewhere, in terms of preparedness for significant winter storms."

'Heavy Lift'

In late October, NERC filed for FERC approval of new reliability standards concerning freeze protection for generation and natural gas facilities impacting the bulk power system (*RD23-1*).

NERC said proposed reliability standards — EOP-012-1 (Extreme Cold Weather Preparedness and Operations) and EOP-011-3 (Emergency Operations) — build on the first round of cold weather standards approved by FERC in 2021, creating "a more comprehensive framework of requirements" on generator preparedness for cold weather operations and requiring TOPs to minimize the use of manual load sheds that could exacerbate emergency

FERC/Federal News

conditions and threaten reliability.

The report prompted *Project 2021-07* (Extreme Cold Weather Grid Operations, Preparedness, and Coordination), which broke the recommendations into two phases, tackling four of them in the standards approved by NERC's Board of Trustees in October and pending FERC approval. (See *NERC Board Approves New Cold Weather Standards*.)

SPP attorney Matthew Harward, the head of the standards drafting team, provided an update on the project at the Standards Committee meeting Dec. 13.

The recommendations in the second phase "are basically further identification of cold weather critical components and systems, and then the implementation of freeze-protection measures on each of those elements identified," Harward said. "Those are GO requirements, and additional GO requirements that will be in the standard are that they must account for the effects of precipitation and wind when determining their lowest temperature [at which they are] able to operate.

"There are quite a few that will impact the BA and the data specifications between the BA, the RC [reliability coordinator], the TOP and the GO. A big one of that is that BA operating plans will need to prohibit critical natural gas infrastructure loads from participating in demand response programs," he added.

The BAs, TOPs, RCs and transmission providers also will have new rules concerning how critical natural gas infrastructure is involved in manual and automatic load shedding.

"So we have some heavy lifts that the team is dealing with. We have a lot of participation from industry … which we feel is a good thing, but it also makes up for a lot of conversation; there's a lot of opinions out there."

Harward said his team is confident it can complete phase 2 and make its recommendations to the board by Sept. 30, 2023.

"It's going to be a little more challenging than maybe we initially thought, but we are definitely up for the challenge," he said. ■

Responses to FERC/NERC Winter Storm Uri Recommendations

Date	Action
April 2022	Texas Railroad Commission and PUCT adopted electricity supply chain map of critical interdependent natural gas and electric infrastructure
April 27-28, 2022	FERC/NERC/Regional Entities held generator winter readiness technical conference
Aug. 30, 2022	Texas Railroad Commission adopts rule requiring natural gas facility cold weather preparedness plans
Aug. 30, 2022	National forum with NAESB, NERC and NARUC on natural gas-electric reliability
Sept. 8, 2022	New England forum on natural gas-electric reliability
Oct. 28, 2022	NERC files new cold weather standards for generator freeze protection with FERC
Ongoing	FERC/NERC/Texas RE scoping and staging blackstart unit availability study for early 2023
Ongoing	ERCOT, MISO and SPP making changes to winter peak load forecasts and reserve margin calculations
Ongoing	NERC committees addressing changes to improve rotational load shed plans and extreme scenario rotational load shed training; improve near-term load forecasts and analyze intermittent generation to improve load forecasts; perform bi-directional seasonal transfer studies, and report times for generation and transmission outages
Ongoing	ERCOT recommending new rule on generator and underfrequency load shed coordination
Ongoing	NERC-FERC team working with NARUC Staff Subcommittee on Electric Reliability and Resilience on matters under state jurisdiction, including generator compensation opportunities for investments; additional rapidly deployable demand response and retail incentives for energy efficiency improvements
Ongoing	NERC Standards development Project 2020-02 on generator ride through initiated to address low frequency effects on interconnections
Nov. 2023	NERC to file additional standards

| *FERC/NERC*

CAISO/West News

CPUC Adopts Contested Net Metering Plan

By Hudson Sangree

The California Public Utilities Commission on Thursday adopted a controversial proposal to revise the state's net-metering scheme for rooftop solar arrays, including by reducing bill credits for new solar owners and incentivizing battery installations.

"We are launching the solar and storage industry into the future so that it can support the modern grid," CPUC President Alice Reynolds said in a statement issued after the vote. "The new tariff promotes solar systems and battery storage with a focus on equity and advances the new clean energy technologies we need to meet our climate goals and help ensure grid reliability."

The vote came after months of wrangling over the plan, which was originally proposed a year ago, then postponed amid public outcry and rewritten to mollify homeowners angry about the possibility of losing their solar subsidies.

The modified *proposal*, approved by a unanimous vote Thursday, says it tries to balance the "multiple requirements of the Public Utilities Code and the needs of the electric grid, the environment, participating ratepayers, as well as all other ratepayers."

It will not change the credits paid to current rooftop solar owners for excess electricity they export to the grid. The state's investor-owned utilities compensate those homeowners at full retail electricity rates, which are much higher than the current costs of utility-scale solar.

The subsidies shift the costs of solar panels from ratepayers who can afford them to those who cannot, Pacific Gas and Electric and other IOUs argued. The "cost shift" amounts to $3 billion to $4 billion a year, the utilities estimated.

The generous payments to those who install PV panels are credited with making California the nation's leader in rooftop solar over the past 25 years.

"Since 1997, California has supported the rooftop solar market through its NEM tariffs, which have enabled 1.5 million customers to install more than 12,000 MW of renewable generation," the CPUC said in a news release last month.

The CPUC's previous net energy metering proposal, issued in December 2021, would have slashed NEM bill credits by more than half and possibly up to 80%, including for homeowners who installed solar panels prior to the plan's adoption. (See *California PUC Proposes New Net Metering Plan*.)

California has 1.5 million rooftop solar arrays generating 12 GW of electricity, the CPUC said. | *Shutterstock*

Under the revised plan, future rooftop solar owners will be compensated differently from existing customers through "an improved version of net billing, with a retail export compensation rate aligned with the value that behind-the-meter energy generation systems provide to the grid and retail import rates that encourage electrification and adoption of solar systems paired with storage," the decision says.

"The successor tariff applies electrification retail import rates, with high differentials between winter off-peak and summer on-peak rates, to new residential solar and storage customers instead of the time-of-use rates in the current tariff," it says. "The successor tariff also replaces retail rate compensation for exported energy with Avoided Cost Calculator values that vary according to grid needs."

A *fact sheet* that accompanied the proposed decision when it was released in November said the new rate structure will encourage customers to install battery storage so they can store solar electricity generated in the daytime and sell it to the grid on hot summer evenings, when prices are higher and the state needs it most for reliability.

Strained grid conditions in the past three summers occurred during heat waves when solar ramped down in the evening but demand remained high from air conditioning use.

The state legislature approved $900 million in funding this year to spur adoption of rooftop solar and battery storage, including $630 million for lower-income households. Those who install solar or solar coupled with storage in the next five years will receive extra payments.

"Customers lock in these extra bill credits for nine years," the CPUC said in the fact sheet.

The solar industry will benefit by selling more storage along with solar arrays, it said.

The adopted plan removed a controversial provision contained in the December proposal to impose an $8/kWh grid charge on solar customers' bills, averaging about $48 per month for residential customers.

The CPUC estimated that under the new plan, residential customers installing solar will save an average of $100 a month on their electricity bills, and those installing solar panels and batteries will save $136 a month or more.

"With these savings … customers will fully pay off their solar systems in just nine years or less," the CPUC said in the fact sheet. ■

CAISO/West News

FERC Restarts Hearing on La Paloma Interconnection Dispute

By Robert Mullin

FERC on Thursday restarted a paper hearing in a dispute over a revised interconnection agreement that would reduce the transmission capacity provided to a 20-year-old gas-fired power plant located in California's Central Valley.

The dispute involves CAISO, Pacific Gas and Electric and CXA La Paloma, owner of the La Paloma Generating Plant in Kern County, Calif. (*ER21-2592*).

La Paloma, which entered service in 2003, struggled financially over the last decade as low-priced renewable resources depressed wholesale electricity markets.

After failing to win an expanded reliability must-run designation from CAISO, the plant declared bankruptcy in 2016, citing rising debt, a difficult regulatory environment and mounting compliance obligations under California's cap-and-trade program.

The ISO refused to authorize a partial closure of the plant, and a new owner acquired the facility in 2018.

La Paloma's original large generator interconnection agreement (LGIA), which FERC approved in 2001, provided the plant with 1,160 MW of interconnection capacity in the CAISO system. When the LGIA expired in August 2021, PG&E proposed a replacement agreement that would reduce La Paloma's interconnection capacity to 1,062 MW, which CAISO asserted had been the maximum net generating capacity demonstrated at the plant's point of interconnection.

Negotiations between PG&E and La Paloma failed to produce a replacement, and in December 2021, FERC accepted the utility's unexecuted agreement, then suspended it for a nominal period, saying it needed more information to determine the reasonableness of the agreement "regarding the amount of interconnection service that should be reflected in the replacement interconnection agreement."

The December 2021 order established a paper hearing, which the commission held in abeyance to allow a settlement judge to help negotiate the dispute. In June, the chief administrative law judge overseeing the matter terminated settlement procedures, saying the parties had reached an impasse.

In its order Thursday, the commission asked the parties to address several points in preparation for the hearing. It:

- directed CAISO to explain which tariffs or manuals, if any, govern the renegotiation of an expiring LGIA, as well as which documents govern "a decrease to the interconnection capacity provided under an expiring generator interconnection agreement, and explain under which conditions interconnection service capacity may be decreased from the amount specified in the expiring generator interconnection agreement."
- asked why 1,062 MW was selected for the proposed replacement interconnection agreement, given that La Paloma's participating generator agreement states the plant has 1,022 MW of generating capacity; the CAISO master file for the plant shows it has a generating capacity of 1,066 MW; the project's peak output in recent years has not exceeded 1,061.3 MWh in any given hour; and the plant's average peak output since 2018 has been 988.95 MW.
- asked La Paloma to provide evidence for its own claims about the capacity and output of the plant.
- directed CAISO to explain whether it conducted PMax testing — which determines the maximum megawatt level that a resource is capable of sustaining — and site visits to the plant during the replacement interconnection agreement negotiations, in line with the ISO's stated practice.

The commission also directed La Paloma to provide documentation supporting its request that the ISO and PG&E compensate the plant for the 98 MW of interconnection capacity the replacement agreement would return to the CAISO system.

Initial briefs from the three parties are due 60 days from Thursday's order. ■

La Paloma Generating Plant in Kern County, Calif. | *MeeFog*

CAISO/West News

APS Can Adopt Flowgate Methodology, FERC Rules

By Robert Mullin

FERC on Thursday approved Arizona Public Service's proposal to begin using the flowgate methodology to calculate available transfer capability (ATC) within its transmission system.

In approving the change, the commission rejected a protest by the Southwest Public Power Agency (SPPA), which complained that APS did not sufficiently explain the impact the move might have on transmission customers and other transmission facility owners in the region.

The commission also denied APS's request to waive a requirement that the utility continue to post total transfer capability (TTC) on its Open Access Same Time Information System (OASIS) after transitioning to the new methodology (*ER22-2476*).

Provider Discretion

The APS proceeding has its roots in FERC *Order 890*, which sought to "increase nondiscriminatory access to the grid by eliminating the wide discretion that transmission providers currently have in calculating" ATC. The order required utilities to develop consistent methodologies for performing the calculation and to publish those methodologies for review.

Issued in 2007, Order 890 revised the *pro forma* Open Access Transmission Tariff (OATT) to require that transmission providers clearly identify the methodology and mathematical algorithms used "to calculate firm and non-firm ATC (and [available flowgate capability] AFC, if applicable) for its scheduling, operating and planning horizons."

APS sought to revise its OATT by replacing the rated system path methodology with the flowgate methodology to calculate ATC across the three horizons.

According to NERC, the flowgate methodology identifies key transmission facilities as flowgates, a mathematical construct used to analyze the impact of power flows on the bulk electric system.

Under the method, NERC explains, "total flowgate capabilities (TFC) are determined based on facility ratings and voltage and stability limits. The impacts of existing transmission commitments (ETC) are determined by simulation. The impacts of ETC, capacity benefit margin (CBM) and transmission reliability margin (TRM) are subtracted from the total flowgate capability, and postbacks and counterflows are added, to determine the available flowgate capability (AFC) value for that flowgate."

In Thursday's order, the commission explained that "In order to have consistent posting of ATC, TTC, capacity benefit margin, and transmission reliability margin values on OASIS, the commission directed public utilities working through NERC to develop the available transmission system capability reliability standard, a rule to convert available flowgate capability values into ATC values." The commission also affirmed that providers relying on the flowgate methodology are required to convert their AFC values to ATC and post the associated calculations on their OASIS and web sites.

The commission noted that, in response to a deficiency letter, APS had provided the required documentation for its various calcula-

| APS

CAISO/West News

tions, including those related to AFC and ATC — as well as its process for converting AFC to ATC.

But the proposed changes prompted a protest by SPPA. While claiming no objection to the use of the flowgate methodology, the power agency said it would be more "sensible" for all entities with component facilities on the APS system to adopt the methodology together.

SPPA also contended that APS' filing with FERC lacked key details about the utility's implementation of the methodology and that APS failed to inform the commission, transmission owners and customers how the methodology would affect transmission allocation and scheduling.

SPPA additionally argued that APS failed to explain how the new methodology would affect other transmission facility owners and transmission customers, particularly those in the Palo Verde area. It asked FERC to reject the changes or suspend APS' filing for five months to either set the issue for settlement judge procedures or a technical conference.

The commission acknowledged SPPA's concerns about transitioning to the flowgate methodology but agreed with APS that Order 890 gives transmission providers discretion in choosing their ATC calculation methodology.

The commission found that SPPA had "not identified any specific concerns with APS' proposed OATT revisions," and that APS had "appropriately revised its OATT to reflect the transition consistent with FERC requirements, finding the revisions to be just and reasonable."

FERC also rejected SPPA's requests to suspend the filing or convene settlement judge procedures or a technical conference, saying "there are no issues of material fact that would warrant a hearing."

'Industry-wide Consistency'

Thursday's ruling also denied APS's request for waiver of the requirement to post TTC values on its OASIS site. The utility had argued that while Order 890 references TTC as a component of ATC, TTC is not actually a component of ATC for providers relying on the flowgate methodology, who instead use TFC in their calculations. APS said the requirement to post TTC on OASIS would be a "burdensome, manual process" with little customer value.

In denying the waver, the commission said Order 890 "addressed the potential for undue discrimination by requiring industry-wide consistency and transparency of all components of the ATC calculation methodology and certain definitions, data and modeling assumptions. The commission [in Order 890] noted its concern that the lack of consistent, industry-wide ATC calculation standards poses a threat to the reliable operation of the bulk-power system, particularly because a transmission provider may not know its neighbors' system conditions and how that might affect its own ATC values."

The commission also found that APS erred in citing previous FERC cases, specifically 2009 rulings involving *SPP* (127 FERC ¶ 61,207) and *Midwest ISO* (126 FERC ¶ 61,107) to support its argument. It noted that the applicant in *SPP* requested only a temporary waiver of the requirement to post ATC, TTC, CBM and TRM values on its OASIS site. In *Midwest ISO*, the commission granted MISO a waiver of the requirement to post certain ATC components on its OASIS site for paths internal to the MISO system, but not for other transmission service requests, the commission added.

"APS has also failed to adequately explain how requiring APS to convert TFC to TTC would impose significant burdens on its staff," the commission determined. ■

CAISO, WEIM Boards Back Reliability Enhancements

By Hudson Sangree

The CAISO Board of Governors and the Western Energy Imbalance Market Governing Body on Wednesday adopted storage and resource-sufficiency upgrades intended to promote grid reliability.

Exercising joint authority on WEIM matters, both boards approved changes to the interstate market's resource sufficiency evaluation (RSE). The test is meant to ensure that each WEIM participant enters a trading hour with enough capacity and ramping capability to supply its own needs and to prevent participants from "leaning" on the market to meet internal demand.

The two bodies adopted a first phase of changes to the RSE in February. Scheduled to take effect this summer, they include provisions to measure a participant's available supply more accurately and allow demand response programs to count toward the RSE. (See *CAISO, WEIM Adopt Resource Sufficiency Changes*.)

The second phase of changes approved Wednesday will allow transfers into balancing authority areas that failed the RSE, subject to surcharges.

"These optional transfers, termed 'WEIM assistance energy,' will enable BAAs that are short supply to access the WEIM's efficient dispatch while still providing incentives for BAAs to participate in the WEIM with sufficient resource to meet their own load," Anna McKenna, CAISO's vice president of market policy and performance, wrote in a Dec. 7 memo to the ISO and EIM boards.

Market participants helped develop the changes through CAISO's RSE enhancements stakeholder *initiative*. NV Energy, for example, raised concerns in February about the RSE being too restrictive and reducing the market's ability to help in potential energy emergencies, which Nevada and California have faced in summer heat waves the past three years.

The utility asked CAISO to develop a mechanism to allow excess supply to "be available to the distressed EIM entity at an appropriate scarcity price," Market Policy Manger Lindsey Schlekeway wrote in a Dec. 14 letter to the boards.

"NV Energy supports the CAISO's final proposal for the resource sufficiency enhancements phase 2 because it creates a financial mechanism that EIM entities can opt in to," Schlekeway wrote. "We recognize this is not a final solution for the resource sufficiency enhancements, but it is of critical importance not to delay the implementation of this reliability enhancement past the summer of 2023 for grid reliability."

The ISO's Market Surveillance Committee (MSC) said in a written opinion that the change will likely produce mixed results, "but we understand that the one or two BAAs that may utilize it believe it will be beneficial. However, it is our belief that these changes still leave the RSE almost certainly in need of further refinement."

Another change exempted CAISO from counting low-priority exports in its RSE obligations.

"This change accounts for interactions between WEIM energy transfers and ISO exports that can occur in the real-time markets and can result in [CAISO] erroneously failing the RSE when it has sufficient internal supply resources to meet its load obligations," McKenna wrote. "WEIM BAAs receiving these exports would still be permitted to count the supported supply towards meeting their RSE obligations."

The MSC supported the change as "it clearly constitutes improvements in the RSE relative to current practice."

Storage Enhancements

Additional reliability enhancements approved Wednesday are meant to better manage an increasing amount of battery storage in CAISO and the WEIM.

The ISO's energy storage enhancements stakeholder *initiative*, begun in February 2021, generated the proposals. California and WEIM participants in the Southwest need battery backup power as solar ramps down late in the afternoon but demand remains high in heat waves from air conditioning use.

CAISO has been adding battery storage rapidly since the rolling blackouts of summer 2020, when it had only 200 MW, and it now has 4,700 MW online, with a goal to add 10 GW or more. Other WEIM entities are expected to add significant amounts of storage in coming years.

The ISO's relatively recent experience with battery storage has led it to make corrections and adjustments, which it expects to continue as it moves forward.

"Most of the storage policy and the market tools that we're using on the system today were implemented at a time before we had very much storage capacity actually operating and performing," Gabriel Murtaugh, the ISO's storage sector manager, said in Wednesday's meeting. "So, this policy really is the ISO looking back on performance of these resources over the last few years and thinking about where we need to go and how we need to evolve."

The grid reliability enhancements include software tools to better account for a storage resource's state of charge when the resource is providing regulation service, requiring it to quickly charge or discharge to meet grid needs. In a September heat wave that brought CAISO close to ordering blackouts, some batteries discharged early and were not available when needed most.

A second component of the effort establishes new bidding requirements for storage resources that provide ancillary services. It requires "scheduling coordinators for storage resources to submit economic energy bids to charge when awarded upward ancillary services, or economic bids to discharge when providing regulation down," McKenna wrote. "This, coupled with the first change, will ensure that a storage resource is available to provide awarded ancillary services."

McKenna noted some stakeholders — particularly Vistra, a major operator of utility-scale battery storage in California — had expressed concern about the new bidding requirements "potentially reduc[ing] how much ancillary services storage resources may be awarded, which could impact resource profitability."

"The ISO recognizes this limitation, [but it] has experienced operational issues during some periods in which storage resources that are scheduled to provide ancillary services may be unable to do so due to either too high or too low of state of charge," she wrote. "This situation can threaten grid reliability if operating reserves from such resources are unable to be deployed during a contingency outage event. This typically occurs when storage resources are at very high or very low levels of state of charge and can be less responsive."

The changes require FERC approval before they can take effect. Vistra indicated in a letter to CAISO that it might challenge the ancillary service proposals, which it said "would lead to inefficient [and] potentially harmful market outcomes in implementation if these proposals are approved by FERC." ■

CAISO/West News

CAISO Board Elects New Chair, Vice Chair

By Hudson Sangree

The CAISO Board of Governors on Thursday elected a new chair and vice chair from among its members and praised outgoing Chair Ashutosh Bhagwat, who is leaving the board after 12 years of service.

Mary Leslie | *LABC*

The board named Mary Leslie to serve as its chair and Jan Schori as vice chair starting Jan. 1, continuing its practice of rotating leaders annually.

Gov. Gavin Newsom appointed Leslie to the CAISO board in 2019. She is the longtime president of the Los Angeles Business Council, a group that works with businesses, government and nonprofits to shape city policy. She was the deputy mayor of Los Angeles under Mayor Richard Riordan from 1994 to 1995 and a commissioner at the Los Angeles Department of Water and Power from 2001 to 2003.

"This is an exciting time to be on the ISO Board of Governors as we transition to a carbon-free power system and enhanced regional coordination throughout the West, and I am honored to have been chosen by my colleagues to serve as the chair," Leslie said in a statement after the vote.

Jan Schori | *© RTO Insider LLC*

Newsom appointed Schori to the CAISO board in February 2021 following her tenure as a NERC trustee for 12 years, the maximum allowed. From 1984 to 2008, Schori worked for the Sacramento Municipal Utility District, one of the nation's largest municipal utilities, including as its CEO and general manager, general counsel and staff attorney.

Governor Angelina Galiteva, CAISO's first female board chair, called the election of Leslie and Schori "yet another historic moment in the history of the board of the California ISO."

"For the very first time, due to this rotation that we've implemented on an annual basis, we have a female chair and a female vice chair, which has never happened before," Galiteva said.

Ashutosh Bhagwat | *UC Davis School of Law*

Newsom next will have to fill the seat left vacant by current Chair Bhagwat, whom former Gov. Jerry Brown first appointed in April 2011. Bhagwat, a University of Davis Law School professor, plans to leave the board by the end of February or as soon as Newsom names a successor.

The board plans a formal sendoff for Bhagwat early next year but recognized his service and recent tenure as chair at Thursday's board meeting.

"Can I be as bold as to take a moment to thank you for your leadership this last year and express our deep sorrow at your family getting to spend more time with you?" Leslie said, prompting laughter. "You will be sorely missed."

Bhagwat thanked the ISO's board, management, staff and its stakeholder community.

"It has been a truly fantastic 12-year run, like nothing else I've had in my life," he said. "I've enjoyed it thoroughly." ■

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

CAISO/West News

TransWest Express to Join CAISO as Tx Owner

By Hudson Sangree

The CAISO Board of Governors voted Thursday to admit a merchant transmission project that plans to bring Wyoming wind to California as a participating transmission owner using a new subscriber model.

The admission of the TransWest Express is still "somewhat conditional," requiring additional steps to complete, including signing up buyers in CAISO for the line's wind energy, Neil Millar, vice president of infrastructure and operations planning, wrote in a *memo* to the board.

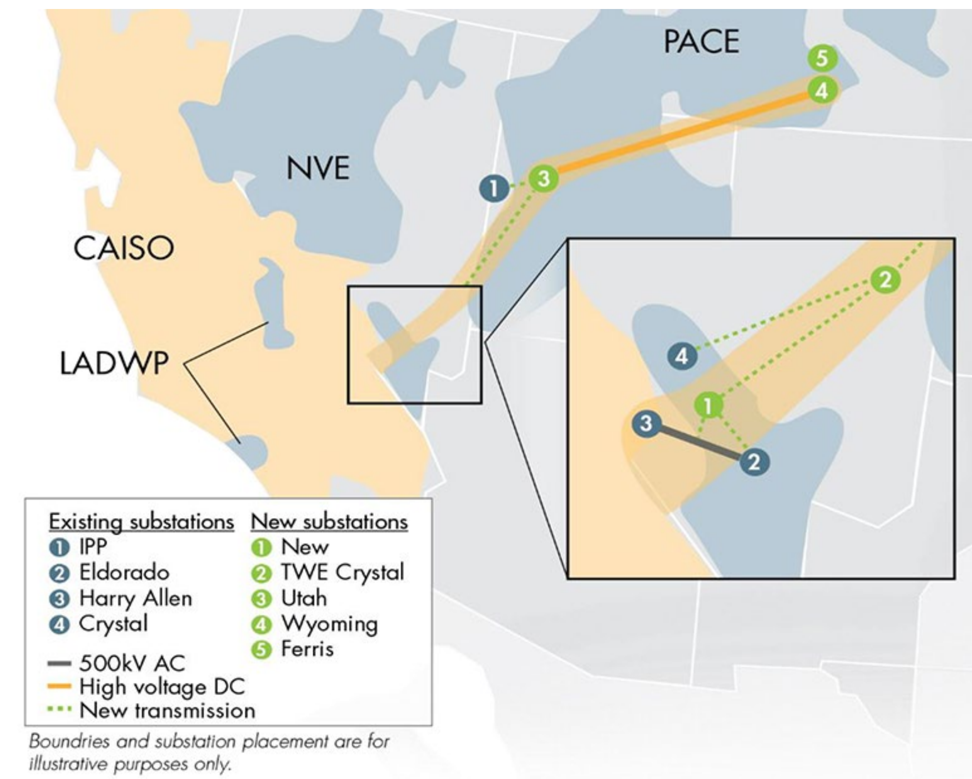
Assuming that happens, the project will expand CAISO's reach hundreds of miles east and establish a new transmission-owner model, Deb Le Vine, CAISO director of infrastructure contracts and management, told the governors in Thursday's board meeting.

"This is a unique opportunity that the ISO has to expand our grid and the way that participating transmission owners come into the ISO," Le Vine said. "The uniqueness is that TransWest Express has already gone through a public solicitation and sold the rights to its transmission lines from Wyoming to California, and then they'll be looking for off-takers for that wind generation — about 3,000 MW of wind that they're looking at bringing in."

Last year, TransWest conducted a *FERC*-approved open-solicitation process that offered firm, long-term transmission service to California via Utah and Nevada. It decided to allocate 100% of its capacity to Power Company of Wyoming, owner of a 3,000-MW wind farm being constructed in the south-central part of the state. FERC approved the arrangement in February.

Both TransWest and Power Company are wholly owned affiliates of The Anschutz Corp., a privately held company based in Denver and controlled by billionaire Phillip Anschutz, who made much of his fortune from fossil fuels and is now seeking to benefit from California's clean energy mandate, which requires 100% of retail energy to be carbon-free by 2045.

To meet the 2045 goal, the state will need to import as much as 10 GW of out-of-state wind by 2040, at least half of it from Wyoming, according to projections by the California Public Utilities Commission and the California Energy Commission.



Adding Transwest Express as a transmission owner would expand CAISO's balancing authority area 600 miles across the West. | *CAISO*

CAISO's recent 20-year transmission outlook examined new transmission needed for the undertaking, predicting overall costs of $30 billion that includes $12 billion to carry wind from the Great Plains and Rocky Mountain states. (See *CAISO Sees $30B Need for Tx Development*.)

TransWest applied to join CAISO in July, saying in its application that it "intends to place under the CAISO's operational control all of [its] project transmission lines and associated facilities … that will connect to the existing bulk power system in Wyoming and Utah as well as directly to the [CAISO]-controlled grid in Nevada."

It would be CAISO's first subscriber participating transmission owner (SPTO), a new model that would give the ISO control of power lines without increasing the ISO's transmission access charge (TAC), currently more than $16/MWh. Some Western entities raised concerns about the SPTO model and asked that it be vetted in a stakeholder process, but CAISO chose to move ahead with the plan. (See *TransWest Express Seeks to Join CAISO*.)

Once built, TransWest will consist of 732 miles of transmission lines in three linked segments: a 405-mile, 3,000-MW HVDC system between Wyoming and Utah; a 278-mile, 1,500-MW HVAC line between Utah and Nevada; and a 49-mile, 1,500-MW HVAC transmission line in Nevada. It will connect in Utah to lines serving the Los Angeles Department of Water and Power (LADWP) and in Nevada to CAISO's grid and balancing authority area.

The project is in an "advanced stage of development, focused on pre-construction matters including tower design and testing; interconnections; contracting with engineering, procurement and construction contractors; and financing," the application said. "All major permits have been acquired, and 100% of the easements/authorizations to build on private lands have been secured." Major parts of the project could be in service by 2026, it said.

Just before Thursday's vote, TransWest Express COO Roxane Perruso thanked the ISO management team for "working with us on our application to become a participating transmission owner and the innovative subscriber PTO model. We think that this is a win-win for everyone … [that] avoids the need for a 39th balancing authority in the West and … particularly a generation-only BA." ■

CAISO/West News

Lacking Low-cost Power Agreement, Wash. Smelter Revival Falters

BPA Balks at Providing Proposed Buyer Guarantee of Cheap Electricity

By John Stang

An effort to reopen Washington's last standing aluminum plant with a lower carbon footprint faltered last week after the company backing the deal failed to secure a guarantee of low-cost power from the Bonneville Power Administration.

For more than two years, a New York City private equity firm, a labor union, the state government and BPA worked to revive the plant near Ferndale, Wash., and hire back the 700 employees laid off when Alcoa shuttered the smelter in 2020. Gov. Jay Inslee wanted the state to contribute $10 million to the revival; shrinking the resurrected plant's carbon emissions figured into his push to combat climate change.

The big hurdle was that BPA and the private equity firm that wanted to buy the former Alcoa Intalco Works, Blue Wolf Capital of New York City, could not agree on terms for BPA to provide electricity for the power-hungry plant.

On Thursday, Blue Wolf broke off talks, BPA spokesman Doug Johnson told *RTO Insider.* The federal power agency is willing to resume discussions if Blue Wolf returns to the table, he said.

Talks broke down over the huge electricity demands of aluminum smelting. When Alcoa owned the plant, it received power at a special industrial rate provided under the 1980 Northwest Power Act. Blue Wolf and a new operating company, Intalco, wanted to buy the facility from Alcoa with the site's industrial power purchase rate intact, but the 1980 law said the rate could not be transferred.

Consequently, the Blue Wolf-BPA talks focused on market rates, which are subject to fluctuation and could move above or below the industrial rate, Johnson said. Blue Wolf wanted a rate similar to the industrial rate, but a fluctuating market could result in other BPA customers paying more to subsidize Intalco's power purchases, he said. The bulk of the BPA's power comes from hydroelectric dams.

Scott Simms, executive director of the Portland, Oregon-based Public Power Council, a coalition of consumer-owned utilities in seven states, including Washington, said Blue Wolf misread BPA's legal obligations

The deal to buy the former Alcoa Intalco Works near Ferndale, Wash., has spluttered over the lack of a power supply agreement. | *Washington Dept. of Ecology*

CAISO/West News

to provide power.

"By Congressional statute, BPA must first and foremost serve the needs of Northwest non-profit public utilities at cost. To the degree BPA has surpluses, it can make excess supplies available to others in the wholesale marketplace," Simms said in an email. "As our Western power grid becomes tighter on available supplies given heightened demands and new climate mandates, BPA must be certain it can supply public power first, as Congress intended.

"I believe Blue Wolf either misunderstood or failed to realize this long-standing BPA statutory obligation to public power. It legally wasn't ever possible for Blue Wolf to step in front of public power's legitimate and rightful obligation to BPA power for a sweetheart deal," Simms said.

Blue Wolf did not reply to a request for comment.

'Huge Employer'

Supporters had hoped to get the Ferndale plant fully running by mid-2024.

The governor's office remains optimistic that the project can be salvaged with new equipment that would trim carbon emissions — mainly sulfur dioxide — below previous levels when Alcoa closed the plant in 2020 due to dropping aluminum prices, a scenario that has played out for smelter across the U.S. The high costs of smelting aluminum, especially due to the volume of electricity required, resulted in the number of the nation's smelters shrinking from 30 in 1985 to six today.

The anti-carbon measures proposed for the Ferndale plant include better scrubbing and filtering of the fumes going up smokestacks. They also include switching from electricity generated by fossil fuels to that provided by wind, solar and hydropower.

The Ferndale plant would need roughly $250 million in improvements and overhauls to get back online and 400 MW of electricity to operate.

In a statement Friday, Inslee's office said "the governor remains committed to the vision of upgrading and reopening the plant as a secure, domestic source of the green aluminum that is critical for our clean energy transition. He stands ready to work with labor and community partners as they continue to seek a solution."

"We are disappointed that negotiations to restart the Intalco aluminum smelter in Washington State, which would provide 700 local high-paying jobs and help secure a domestic supply of low carbon aluminum appear to have failed," Annie Sartor, aluminum campaign director for Industrious Labs, said in an email. Industrious Labs is a Cincinnati-based think tank focusing on helping industries grow while coping with climate change issues.

Sartor wanted the Biden administration and Congress to invest in reviving aluminum manufacturing with renewable energy. Aluminum is a key component in building electric vehicles, solar panels and transmission lines.

Meanwhile, the likelihood of 700 resurrected jobs in Ferndale has taken a huge hit.

Luke Ackerson, business manager of the International Association of Machinists Local No. 160, remembers when the plant shut down during the pandemic in 2020. "Some worked there for 30, 40, 50 years, and you would see on their faces 'What am I gonna do next?'" Ackerson said last month. "Ferndale is a small town, and this is a huge employer." Ackerson could not be reached for additional comment.

Brian Urban, who worked as a bricklayer at the plant, said of the plant's closing: "It came as a complete surprise. Some people got angry. Some people got completely depressed. There were some suicides. Some marriages suffered." Urban and his wife coped, and he continued as a bricklayer for Local 160.

The union had negotiated a contract with Intalco that would have kept the Alcoa-level wages and would give the workers partial ownership of the plant.

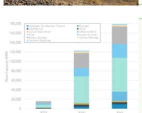
Meanwhile, Intalco expected to negotiate a "bridge contract" of a few years to obtain electricity from traditional sources before switching entirely to alternative power sources such as solar and wind, Intalco CEO Mike Tanchuk said in an interview last month. He could not be reached for comment after the BPA talks ended Thursday.

U.S. industry has an annual aluminum demand of 5 million metric tons (MMT). American smelters produce 1 MMT a year, while another 2 MMT come from Canada. The remainder comes from overseas, including 300,000 metric tons a year from Russia. The Ferndale plant could produce 235,000 metric tons annually, which would make up most of the aluminum imported from Russia, said Joe Quinn, director of the Center for Strategic Industrial Materials, a D.C.-based think tank.

China produces more than 60% of the world's aluminum, primarily through coal-fired electricity. The world's leading producer of aluminum using carbon-free, hydro-powered energy is Russia, Quinn said. ■

West news from our other channels

Inslee to Seek $10M for Energy Research Program in Central Wash. NetZero Insider



CARB Approves Plan to Reach Net Zero by 2045 NetZero Insider

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CEC Approves $2.9B Clean Transportation Plan NetZero Insider

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

CAISO/West News

Settlement Hearing Ordered for PG&E, SF Distribution Dispute

FERC Decision Comes After DC Circuit Vacates Previous Order

By Robert Mullin

FERC on Thursday ordered settlement judge procedures for a three-year-old dispute between Pacific Gas & Electric and the city and county of San Francisco over the provision of distribution service.

At issue was a 2019 complaint the city filed with FERC alleging that PG&E had violated its wholesale distribution tariff (WDT) by refusing to provide lower-voltage secondary service to many sites within the city.

Last week's order comes nearly a year after the D.C. Circuit Court of Appeals remanded the matter back to FERC after overturning the commission's unanimous 2020 decision rejecting San Francisco's complaint (*EL19-38*). (See *San Francisco Wins Against PG&E, FERC in DC Circuit*.)

In its original filing, the city alleged that PG&E had consistently refused to make new interconnections at secondary voltage unless the total electricity demand was less than 75 kW and instead offered to connect higher-voltage primary service, which requires the installation of transformers and carries higher fixed costs for ratepayers, inhibiting the installation of rooftop solar.

The city argued that the practice violated PG&E's tariff, which it said requires the utility to offer secondary service when requested and to expand its infrastructure where necessary.

The utility countered that it did not categorically deny secondary service in cases where demand exceeded 75 kW and said its denials in some cases were based on technical, safety and reliability concerns.

FERC denied the complaint in April 2020, ruling that PG&E should decide what level of service is appropriate for customers, and upheld the decision on rehearing later that year in another unanimous vote.

But in a January 2022 opinion, a three-judge panel of the D.C. Circuit found that FERC failed to scrutinize the safety and reliability risks cited by PG&E. The court also rejected PG&E's contention that it decides appropriate voltages case by case.

"Evidence before the commission showed that since 2015, many of San Francisco's new interconnection requests exceeding 75 kW have been denied secondary service by PG&E, and that the proportion of new interconnections above 75 kW receiving primary service has increased since 2015," the court said. It cited a July 2019 letter written by PG&E to San Francisco saying it was no longer "willing to make additional accommodations" for secondary service.

Distribution lines in San Francisco. | *Contractors Insurance Agency*

Faulty Guidepost

In re-examining the record on remand, FERC found that "PG&E's application of an unofficial and unwritten 75-kW threshold for providing secondary service for San Francisco customers violates the filed rate doctrine, and that the criteria by which PG&E determines service level must be included in its WDT."

The commission also concluded that FERC's record contains "insufficient support" to find that the 75-kW threshold is "just and reasonable," and that the record requires further development to determine when primary service is required under the WDT.

The commission noted that the filed rate doctrine forbids utilities from charging any other rate than the one filed with FERC, adding that the principal "extends to utility practices that affect rates and service."

"Relatedly, the rule of reason requires public utilities to file for commission approval 'practices that affect rates and service significantly, that are realistically susceptible of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous,'" the commission wrote, citing a 1985 D.C. Circuit opinion.

The commission said it had previously determined that the 75-kW threshold did not need to be included in the WDT because it viewed the threshold as an "initial guidepost for which primary service can be expected," noting the multiple occasions PG&E had granted secondary service for installations exceeding 75 kW. But the D.C. Circuit ruled that, even as a "guidepost," the 75-kW threshold was the kind of "numerical threshold" that the "rule of reason" required to be included in the WDT.

"Given the court's direction on remand, we find that under the rule of reason PG&E must include in the WDT the thresholds and other criteria used to determine whether a customer receives primary, primary plus or secondary service," the commission said.

The commission also found that the record does not demonstrate that the 75-kW guidepost would itself be just and reasonable for determining which points of interconnection should receive either primary or secondary service.

"For example, while we recognize that the WDT serves a different purpose and applies to different customers than PG&E's retail tariff, and while that retail tariff is not subject to the commission's jurisdiction, PG&E has not sufficiently explained why the 3,000-kW threshold it applies in the retail context is not appropriate for determining the type of wholesale distribution service available to a point of delivery under the WDT," FERC said.

The commission further found that it is unclear that a kilowatt threshold is either necessary or sufficient for determining whether an interconnection should be served with primary or secondary service, rather than "specified reliability, safety or operational criteria," which could possibly be considered in conjunction with a kilowatt threshold.

"For these reasons, we find that San Francisco has demonstrated that the WDT must include the specific criteria that PG&E uses to determine whether a wholesale distribution service customer is eligible to receive primary, primary plus, or secondary service at a requested point of delivery," the commission wrote.

FERC said the settlement hearing should examine those issues and explore what San Francisco points of interconnection, if any, that were provided primary service should have been provide secondary service since the time of the original complaint until a revised WDT becomes effective and the appropriate amount of refunds owed to San Francisco as a result. ■

Hudson Sangree contributed to the reporting in this article.

ERCOT News

Stakeholders Respond to ERCOT Market's Proposed Redesign

Texas Regulators Schedule January Work Session to Discuss Feedback

By Tom Kleckner

Texas regulators have received almost 120 comments from ERCOT stakeholders and the public about their proposed market redesign, feedback they will review and discuss before turning over their final recommendation to lawmakers next year.

From global energy powerhouses like Shell Energy, to individual ratepayers, commentators have given the Public Utility Commission hundreds of pages for their holiday reading pleasure. Stakeholders had 35 days to file their comments before a Thursday deadline (*54335*).

The comments echo those made by lawmakers during recent public hearings: The PUC's preferred market design is too complicated and an unknown among other grid operators. There is no reliability standard. It won't attract new baseload generation to Texas.

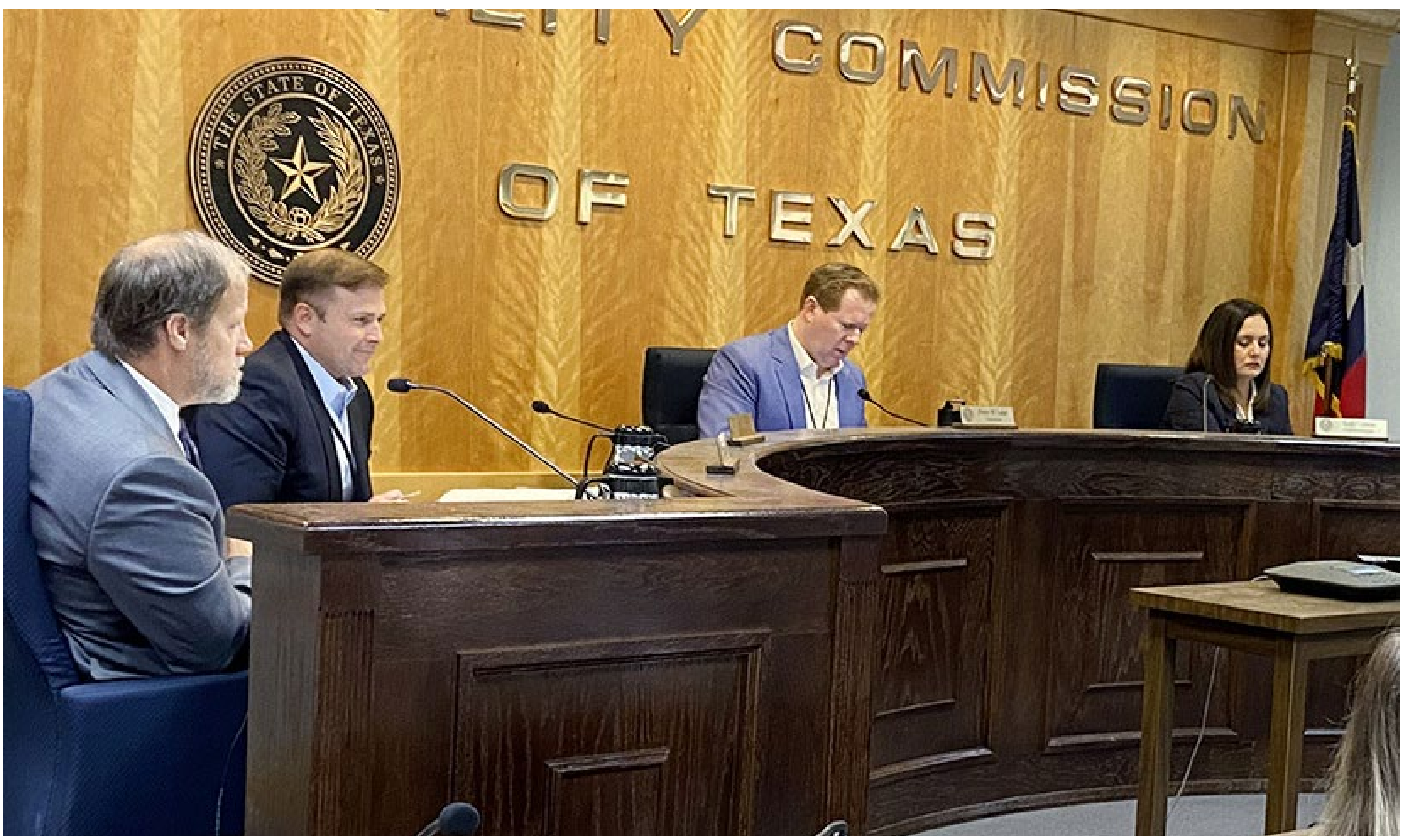
A San Francisco-based energy consulting firm spent several months modeling and analyzing market designs proposed by the PUC following public work sessions after the deadly 2021 winter storm nearly collapsed the ERCOT grid. Energy + Environmental Economics (E3) recommended a forward reliability market construct that relies upon a centrally cleared auction procuring the "requisite" amount of reliability credits.

PUC staff instead urged the commissioners to pursue a performance credit mechanism (PCM) that requires load-serving entities to buy performance-based credits from generation resources in a voluntary forward market. The credits are awarded to resources through a retrospective settlement process based on availability during the 30 hours of highest risk, according to their load-ratio shares during those same periods. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

Potomac Economics, ERCOT's Independent Market Monitor, *said* it found the PUC's first phase of market changes to be "far more effective and more sound economically" than the proposals in E3's report. The early modifications included a 44% reduction in the market's price cap to $5,000/kWh and shifting the operating reserve demand curve (ORDC) so that the market's shortage-pricing mechanism increased real-time energy revenues by $1.7 billion this year through November, according to Potomac.

"We continue to believe in the effectiveness of the energy-only market," the Monitor wrote. "The energy-only market is an effective pay-for-performance mechanism and should be retained in full without adding an unnecessary separate availability payment structure that would be difficult to accurately hedge or predict due to its *ex post* procurement."

Potomac recommended against the PUC moving forward with any of its designs, saying the PCM is "a less effective and efficient means to facilitate performance by ERCOT's generation fleet" than the current construct. It did allow that the PCM would be "less disruptive" to the current market than the backstop reliability



The Texas regulatory commission will have its hands full digging through stakeholder comments on ERCOT's market redesign. | *© RTO Insider LLC*

ERCOT News

service (BRS) mechanism, an ancillary service meeting specific reliability needs during high uncertainty periods.

The Steering Committee of Cities Served by Oncor *wrote* that the PUC's ultimate goals and principles in redesigning the market remain "unclear." It called on the commission to direct E3 to revise and expand its analysis, saying the firm's report is "inadequate as a basis for such a momentous redirection of the state's and consumers' energy resources."

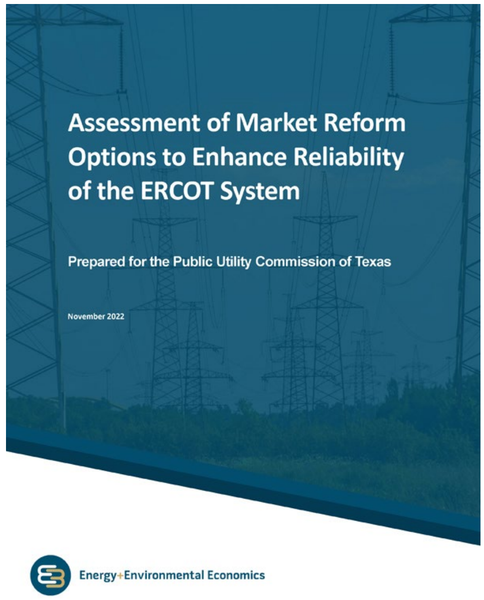
The Texas Public Policy Foundation, a nonprofit organization *pushing the oil and gas industries' interests*, took aim at the "overinvestment" in renewable energy, saying any new market design needs to also address "underinvestment" in dispatchable generation.

"Any program that only addresses the underinvestment problem is simply countering the federal subsidies for wind and solar with state subsidies for dispatchable generation and will lead to skyrocketing costs for ratepayers," the foundation *said*.

The PCM also has its supporters. *Vistra* and *NRG Energy*, the state's two largest generation owners, favored the PUC's recommendation.

The R Street Institute — a nonpartisan, public policy research organization that last year pushed its own version of the PCM — *called* the PUC's preferred design a "workable framework" that will add "additional incentives for installed [reserve] capacity."

The Texas Competitive Power Advocates (TCPA) — a trade association representing generators, wholesale marketers and retail providers — *said* it stands ready to bring more than 4.5 GW of additional generation to ERCOT if the PCM is adopted under the "right framework."



ERCOT market participants have plenty to say about a consultant's report on the ERCOT market's redesign. | *E3*

"The E3 report demonstrates that the status quo energy-only market will not incentivize sufficient new generation or retain sufficient existing generation to ensure resource adequacy and reliability outcomes acceptable to Texans," TCPA Executive Director Michele Richmond *wrote*. She said the PCM will meet the objectives of legislation passed year that requires a reliability standard for the grid and a market design ensuring reliability during extreme weather and periods of low non-dispatchable power.

"The [PCM] can achieve this; alternative and unstudied half-measures cannot," Richmond said. "Nor can state-subsidized generation or loan programs, which may marginally reduce the cost of new generation but would also accelerate the retirement of the gas generation that kept the power on this summer."

The PUC has scheduled a work session on Jan. 12 to discuss the design proposals and stakeholder feedback. A vote is not expected on the proposals during that meeting, but a plan is expected to be adopted later in the month, a commission spokesperson said.

"As [PUC Chair Peter Lake] has repeatedly assured, the commission will continue to work closely with the legislature on this important issue," Rich Parsons said in an email to *RTO Insider*.

ERCOT's Kenan Ögelman, vice president of commercial operations, *said* it will take at least 1.5 to 2.5 years and up to $4 million to implement the PCM, assuming the project can be done concurrently with the delayed real-time co-optimization (RTC) market tool's development. He said that estimate is in addition to at least six months to write the necessary rules and protocols.

In comparison, delivering the BRS will take between 15 months and 2.5 years, Ögelman said. Again, this assumes the design's work will be managed alongside that of the RTC tool. (See *ERCOT Technical Advisory Committee Briefs: Dec. 5, 2022*.)

"There is significant overlap in the systems that would be impacted by implementation of PCM and BRS, as well as the employees who would be needed to work on those projects," Ögelman wrote. "As such, a decision to implement one program would significantly impact the timing of when the second program could be delivered." ■

ERCOT Briefs

Texas Grid Prepared for Winter's First Frigid Blast

ERCOT on Friday issued an operating condition notice to the system's generators in advance of a polar blast that will drop temperatures below freezing next weekend.

The procedural notice alerts the grid operator's market participants that temperatures will be 25 degrees Fahrenheit or lower in the Dallas and San Antonio metro areas from this Thursday through Dec. 26. It is the lowest of ERCOT's four emergency-level communications.

ERCOT on Saturday projected demand to peak at 69.7 GW at 10 a.m. on Dec. 23, more than 2 GW more than its forecasted winter peak of 67.4 GW in its seasonal assessment released in November. (See *ERCOT Says 'Sufficient' Capacity to Meet Winter Demand*.)

"As we monitor weather conditions, we want to assure Texans that the grid is resilient and reliable," ERCOT CEO Pablo Vegas said in a *press release*. "We will keep the public informed as weather conditions change throughout the coming week."

Meteorologists have said the cold weather could threaten regional records that date back to 1983 but won't be as bad as the deadly 2021 winter storm that almost brought down the ERCOT grid.

"The duration of this cold, the lack of snow and ice, and the intensity of the cold statewide will still lag February 2021, so at this point, we'll take ERCOT at their word that grid conditions should be manageable," Space City Weather meteorologist Matt Lanza *said*.

The Texas grid operator said it has sufficient generation to meet the forecasted demand and will continue to provide updates. The primary concern remains natural gas production, where wellheads can freeze and pipelines lose pressure. It was the lack of supplies from the gas fields that led to much of the generation problems during the 2021 storm.

ERCOT has increased weatherization requirements and improved coordination with the gas industry since the storm.

Fuel Mix Dashboard Added to Website

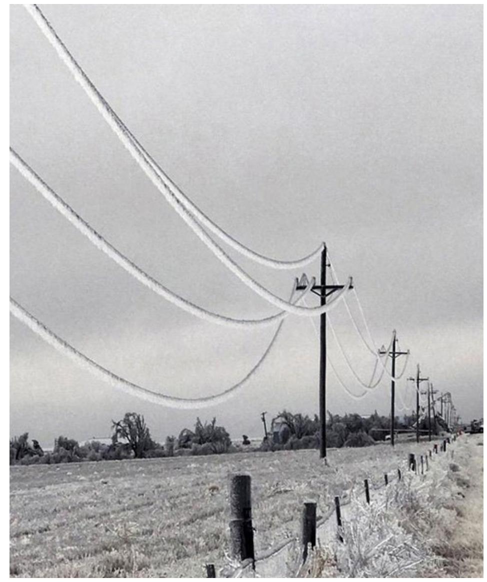
The grid operator has unveiled a new *fuel mix dashboard* on its website that provides a real-time view of energy generation by resource type.

The dashboard offers several views of energy generation. The real-time view shows the current percentages of energy generated by resource type, with current and previous day options that can be displayed in a stack view or a line chart.

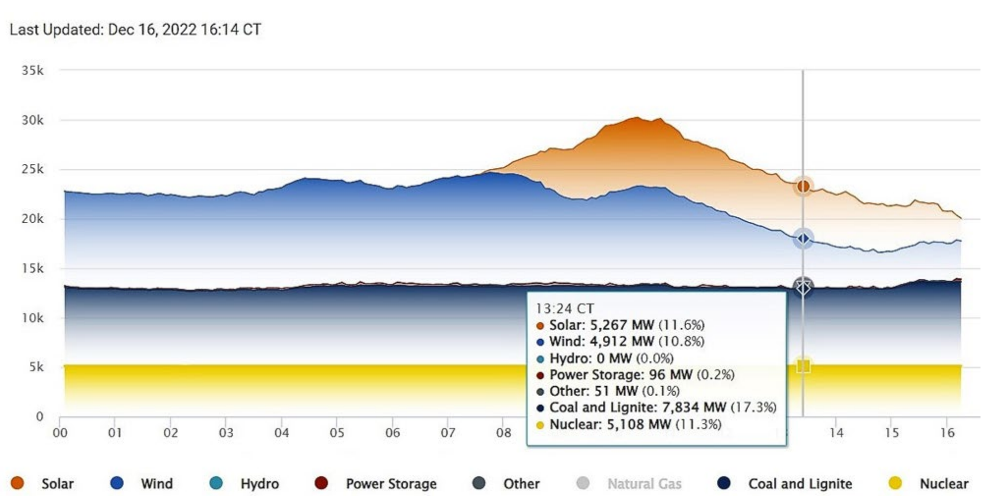
The fuel mix includes "power storage" as the output from energy storage resources when they are discharging power. Under current market rules, power consumed by storage resources when they charge is included in system load.

Dan Woodfin, vice president of system operations, said the dashboard is the "latest in a series of improvements to increase public visibility" into ERCOT.

The dashboard is accessible from the *Grid and Market Conditions* page on ERCOT's website.



Wintry conditions are expected to return to Texas this weekend. | *Xcel Energy*



ERCOT has added a real-time fuel mix dashboard to its website. | *ERCOT*

Brazos Repays Market $1.15B

ERCOT will begin distributing holiday gifts to market participants today after an initial payment of $1.15 billion from Brazos Electric Power Cooperative last week. The cooperative declared Chapter 11 bankruptcy following 2021's disastrous winter storm and only recently had a reorganization plan approved by a federal bankruptcy plan. (See *Bankruptcy Judge Approves ERCOT-Brazos Settlement*.)

Under the terms of a settlement agreement between ERCOT and Brazos, the cooperative will eventually pay the grid operator $1.4 billion to resolve its short pay to the market. The $1.15 billion Brazos sent to ERCOT on Thursday will be followed by 12 annual payments of $13.8 million.

In a *market notice*, staff told market participants the first payment will fully replenish $599.7 million for congestion revenue rights funds that they used to reduce the market shortfall, attributable to Brazos' short-pay, immediately following the winter storm. The funds will also be used to pay eligible market participants for their allocable portion of the Brazos short-pay claim.

The timing and amount of payments to eligible market participants will be determined by the payment option they elected or were assigned. ■

— Tom Kleckner

NECA Panelists Talk Capacity Market, DERs

By Sam Mintz

A panel of energy experts took ISO-NE's capacity market to task this month, lambasting the region's Forward Capacity Market and offering ideas about how to improve it.

The panel at the Northeast Energy and Commerce Association's Power Markets Conference, held Dec. 5, was titled "Can Markets Get Us More Reliable?"

And while the answer from the group wasn't an unconditional "no," it involved heavy criticism for the way the capacity market is currently set up.

William Hogan, Harvard University | © *RTO Insider LLC*

"I've always viewed forward capacity markets as the original sin of market design," said William Hogan, a professor of global energy policy at Harvard University.

"I know it's politically embedded in the system … but I don't think they're a solution to any real problem other than mailing checks to people," Hogan said.

When it comes to ISO-NE's markets specifically, Sheila Keane, director of analysis at the New England States Committee on Electricity, said that there's a lack of a "clear measurement or goalpost" for energy adequacy.

Sheila Keane, NESCOE | © *RTO Insider LLC*

"If we're thinking about changes to the capacity market, that's something the states are always open to having discussions [about]," she said.

David Patton, president of Potomac Economics, ISO-NE's External Market Monitor, said the FCM isn't a viable solution to most of the problems that New England's grid faces.

"It's not a very good solution for resource adequacy to begin with, but when you start to look at some of the challenges we're facing with reliability and the introduction of intermittents, it becomes less and less reliable," he said.

And Ben Griffiths, regulatory policy director at LS Power, rounded out the critique with an academic bent.

Ben Griffiths, LS Power | © *RTO Insider LLC*

"On the capacity market side, there is not enough liberal arts thinking," he said. "It's not clear to people what they're actually buying, or what [the one-day-in-10-year loss of load standard] is actually doing."

David Patton, president of Potomac Economics, ISO-NE's External Market Monitor, participated remotely with a group of energy experts at the NECA Markets Conference last week. | © *RTO Insider LLC*

DERs and Blurred Lines

On a later panel, titled "Blurring of Wholesale and Retail Lines," experts laid out the importance of distributed resources for the energy future, and of markets and pricing that help incentivize them.

Greg Geller, head of regulatory affairs at Enel North America, laid out a bevy of benefits from greater DER utilization in New England, including reduced transmission costs, better price signals for emissions reduction, help with winter reliability issues and more.

But to do that, the region needs strong and flexible retail programs, the panelists said.

Part of the challenge is that different entities regulate overlapping spaces, said Caitlin Marquis, director of Advanced Energy Economy.

Caitlin Marquis, Advanced Energy Economy | © *RTO Insider LLC*

That's been demonstrated by the compliance process for FERC Order 2222, which requires RTOs and ISOs to provide DERs access to wholesale electricity markets.

"The compliance directive was on the ISO, not on the states or retail regulators — but they have an important role in implementing pieces of Order 2222," Marquis said.

Henry Yoshimura, ISO-NE | © *RTO Insider LLC*

ISO-NE is thinking carefully about how to integrate demand resources in the region, said Henry Yoshimura, the grid operator's director of demand resource strategy.

"What do we need? Retail rates that reflect time-varying costs," he said.

"Retail prices should be high when marginal costs are high and should be low when they're low," Yoshimura added.

Without the right rate design, he said, "you're never going to get the right demand flexibility" from DERs and other such resources. ■

ISO-NE News

Renewable Group Asks FERC for Interconnection Cost Changes in NE

By Sam Mintz

RENEW Northeast is asking FERC to shift the burden of network upgrade operations and maintenance costs in ISO-NE off of interconnection customers.

In a *complaint* filed last week, the organization argued that the policy, contained in schedules 11 and 21 of Part II of ISO-NE's tariff, is unjust and unreasonable.

"ISO-NE is the only region in the United States in which interconnection customers are directly assigned all capital cost and all ongoing O&M costs for network upgrades, regardless of who causes the network upgrades or who benefits from the network upgrades," RENEW wrote in its complaint.

Since Order 2003 nearly 20 years ago, FERC's policy has been to require interconnection customers to initially fund the cost of network upgrades that would not have been required without that specific interconnection, but not to let transmission owners assign customers ongoing O&M costs.

"There was never any rationale behind this exemption from the commission's O&M policy other than it having been a transitional measure included in New England Power Pool's transition to an ISO and its Order No. 2003 compliance filing," RENEW wrote. "Continued direct assignment of O&M costs to interconnection customers is not just and reasonable and should be rejected."

RENEW sees it as an issue especially for its members — renewable generators — because the process of interconnection can be especially unwieldy for new generation projects, and the direct assignment of O&M costs adds another burden and barrier to entry.

It's one of the factors that could cause projects to withdraw late in the interconnection process, according to RENEW.

"Since network upgrades provide a system-wide benefit, expenses associated with owning, maintaining, repairing and replacing them should be recovered from all transmission customers rather than being directly assigned to the generator," said Francis Pullaro, the group's executive director.

RENEW tried to bring a change to address the problem through the NEPOOL process, but it missed the two-thirds vote required to advance through the Transmission Committee. In the complaint, it's asking for FERC to issue an expedited order finding those portions of the tariff unjust and unreasonable. ■

| © RTO Insider LLC

ISO-NE News

FERC Moves to Implement New Backstop Transmission Siting Authority

By Sam Mintz

FERC on Thursday approved a Notice of Proposed Rulemaking that would pave the way for overriding state regulators' rejections of certain transmission projects (*RM22-7*).

Congress originally gave FERC this backstop siting authority for transmission projects in Department of Energy-designated National Interest Transmission Corridors as part of the Energy Policy Act of 2005. But the 4th U.S. Circuit Court of Appeals ruled this only applied to those projects that state regulators did not act on, not to those that states denied. (*Piedmont Environmental Council v. FERC (2009)*)

A provision in last year's Infrastructure Investment and Jobs Act essentially overturned that ruling, expanding FERC's backstop authority over state-rejected projects. The NOPR is intended to implement that provision.

"The NOPR clarifies the commission's siting authority by expressly stating that the commission may issue a permit for the construction or modification of electric transmission facilities in DOE-designated national corridors if a state has denied an application to site transmission facilities," Abigail Christoph, an attorney-adviser in the Office of General Counsel's, said in a *presentation* at FERC's open meeting Thursday.

It would also allow developers to begin prefiling proceedings for their projects with FERC while its state applications are pending, instead of waiting for one year after they submit them.

"This change will allow applicants to simultaneously pursue approval before a state and the commission if they so choose," Christoph said.

Transmission wonks generally consider federal backstop siting authority necessary for building large, interregional projects, as just one state can unilaterally kill a multistate project if it rejects its developer's application. It is a deeply unpopular concept with state regulators, however.

FERC acknowledged this in the NOPR by proposing several rule changes aimed at ensuring a thorough process if a developer requests that it override a state's rejection.

The commission would create a new applicant "code of conduct" for how potential permit holders engage with landowners. It would also require three "resource reports" be included in applications: on environmental justice, tribal resources, and air quality and environmental noise.

Republicans Tentatively Approve

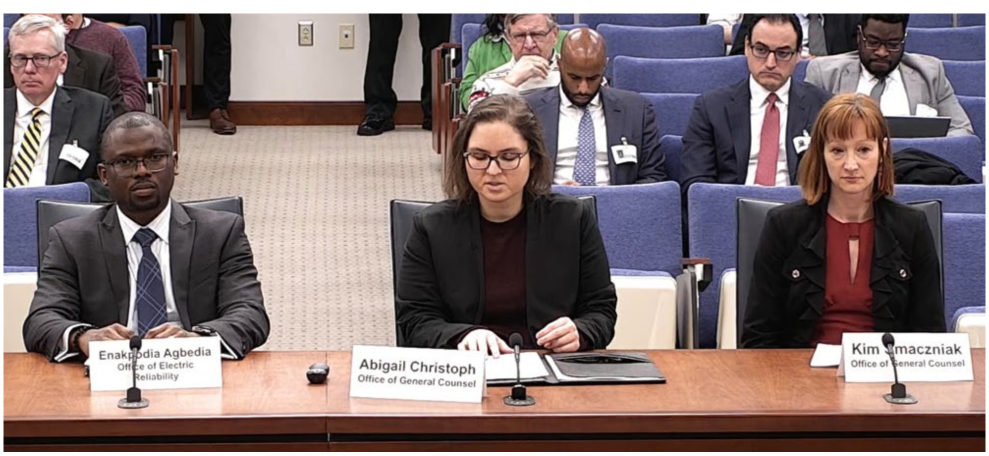
All five FERC commissioners voted to approve the NOPR, but they didn't agree on whether it will actually help build out any transmission projects.

"Infrastructure is extremely difficult to site in the United States," Chair Richard Glick said. "It's something that, as a country, we need to come to grasp with, especially in regards to transmission. ... We have to get it done as a country, and I think this is a step in the right direction."

Fellow Democratic Commissioner Allison Clements pointed to the provisions that add new requirements for engaging with landowners and other stakeholders as helpful to getting projects done and avoiding litigation.

"It's really hard to build infrastructure because that impacts people. So let's find ways to bring people into the conversation early on and get satisfactory outcomes," she said.

Commissioner Mark Christie said it's a "false narrative" that states are blocking transmission. | *FERC*



Abigail Christoph and Kim Smaczniak, of the FERC Office of General Counsel, and Enakpodia Agbedia, of FERC's Office of Electric Reliability, brief FERC commissioners on the NOPR. | *FERC*

But Republican Commissioner Mark Christie challenged both the premise of the new rules — that states are blocking transmission buildout in a meaningful way — and their function.

"This narrative that's being pushed — that the states are standing in the way of critically needed infrastructure — is a false narrative," Christie said.

He noted that the transmission rate base around the country has almost tripled in the last 10 years.

"The states are not standing in the way of critically needed transmission projects. The states are by and large approving them. If the states need anything, they need more authority to vet projects, not less," he said.

Christie also said the rule changes would not be a "magic bullet" that results in more transmission. Instead, he said, they would create multiple lines of attack for litigation opposing new transmission lines.

"The first time FERC overturns a state after the state has said 'no,' once the state has held its own formal process and said 'no' either on the route or the need or the prudence of cost ... that's going to be litigated 16 ways from Sunday," he said.

Still, Christie said he would approve the NOPR, though he said he wanted to hear from state regulators and consumer advocates.

"I question the purpose of fidelity to the IIJA in a NOPR that has what I think in many cases are unnecessarily burdensome requirements, but ... I solicit comments on that," Commissioner James Danly said. ■

ISO-NE News

Experts Call for More Granular Clean Energy Procurement

By Sam Mintz

A parade of experts extolled the virtues of more granular clean energy purchasing at Raab Associates' New England Electricity Restructuring Roundtable earlier this month, calling it essential to meeting climate goals in the region and around the country.

Citing the limitations of the widespread annual matching that makes up most corporate and institutional clean energy procurement, the academics and policymakers also called for grid operators to develop data to help lead the charge.

"In order to fully decarbonize our electric grid in New England, we will very likely need to realign our policies, procurements and supporting data from its current broad-brushed monthly and annual matching frameworks to ones that focus either on a much shorter period time, such as hourly, or on marginal emissions rates, or both, as well as more granular locational matching," said Jonathan Raab, convener and one of the moderators at the event Dec. 9.

Jesse Jenkins, a Princeton University professor and prominent energy expert, laid out the problem: While voluntary clean energy procurement through long-term contracts has helped finance renewable projects, it has significant limitations that are becoming more clear.

"There are times when the production from wind and solar is quite a bit lower than the consumption from the procuring consumers," Jenkins said. It's a mismatch that "limits the ability to reduce CO_2 emissions associated with the buyer's consumption."

A solution that's coming to the fore, led by some major corporate buyers, is 24/7 matching, where companies try to purchase clean energy that matches their demand hour by hour, from within the same region.

"I think 15, 20 years ago, probably the best we could have done was annual matching. It made sense to make an assumption that all clear resources are equal," said Kathleen Spees, a principle at the Brattle Group. "It's certainly not always true now."

Hour-by-hour carbon-free procurement enables "deeper emissions reductions than annual matching," Jenkins said.

Panelists talk about 24/7 emissions matching at this month's Raab Roundtable. | *New England Electricity Restructuring Roundtable*

And it drives early deployment of advanced technologies, helping to create "niche markets" that can help pull forward technology like clean firm generation and long-duration storage.

But there's a key reason why more companies aren't doing this yet: It's expensive.

"There is a cost premium for first movers who want to go from annual matching all the way up to 100%, or near 100% hourly," said Mark Dyson, managing director for carbon-free electricity (CFE) at RMI.

Dyson worked on a project with Microsoft last year to assess the costs, emissions impacts and system transformation impacts of procuring CFE on an hourly basis to match their load.

It's the tech giants that have been the earliest movers in the space. Along with Microsoft's work, Google is one of the first companies to start diving deep into 24/7 matching.

At the second panel of the day, moderated by Janet Gail Besser, vice president of the Smart Electric Power Alliance, Google's head of energy market development and policy, Caroline Golin, laid out the company's plans.

"Our goal is that every hour of every day, all of our facilities will match our energy use with carbon-free energy, and that all of that energy will be procured locally within the balancing authority or RTO in which we operate," Golin said.

It's an evolution of the company's goal to use 100% renewable energy to power its operations.

"Google's a large company that has invested a lot of internal resources and deployment of capital to meeting our clean energy goals. We recognize that we're a unique player in the field," Golin said.

It's also trying to help other companies learn from its experience, *sharing information* about its business model.

"The leadership that we're seeing from corporate buyers is really exciting," said Spees, who noted that they don't have the same constraints as public entities. "They can just sign a contract around a corporate objective they believe in."

A Data Problem

Another challenge with more granular matching is that it requires a heavier lift with data, both for companies looking at their consumption and for grid operators or other entities measuring emissions.

"There is no market structure to date that is built for a completely decarbonized electricity system," noted Golin.

Misti Groves, vice president of the Clean Energy Buyers Association, said that her members need more to go on.

"To do more, customers need accessibility, transparency and a standardized format," she said, adding that a centralized database would be ideal.

"Right now, companies are using inferior datasets that are not reconciled," she said.

A number of corporations can't accurately measure their consumptions, she said.

"You'd think a fundamental question is, what's your load? What's your consumption?" Groves said. "A baseline is incredibly important."

Tanuj Deora, director of clean energy at the White House Council on Environmental Quality, laid out the *framework*, in the form of an executive order, that the Biden administration has set to increase the government's procurement of carbon free electricity.

"We wanted to have a strategic shift, recognizing that we are the largest buyer in the country and therefore have a lot of influence with suppliers," he said.

Geography matters, Deora added.

"We focused on the idea that high levels of CFE are possible, and that there are going to be different pathways, balancing area by balancing area," Deora said. ■

ISO-NE News

New England's New Gen Giant Sees Future in Hydrogen, Not Renewables

By Sam Mintz

The Japanese company that just bought up a significant portion New England's energy generation doesn't see its decarbonization future in renewables, its CEO said at a conference last week.

JERA Americas, the U.S. division of Japanese energy giant JERA, recently purchased two gas plants in Massachusetts and Maine.

The deal was approved by FERC, despite objections from consumer advocates that it would threaten competition by giving the company too large a share of the generation market in New England, particularly in Southern New England, where it now controls 18% of generating capacity. (See *FERC Approves New England Generation Deal Over Competition Objections.*)

JERA Americas CEO Steve Winn made some of the first public comments about the company's plans for its newly increased footprint in the region last week at the New England Energy Summit.

The company is interested in the Northeast because it shares similarities with Japan, he said, including relatively high population density, limits on the potential for new construction and decarbonization goals.

But the company's goals aren't necessarily aligned with that of regional policymakers who have pushed for building more renewables.

"Our focus on decarbonization is really on low-carbon fuels," he told the conference.

JERA owns around 5 GW of renewables globally, made up of small projects in Asia and Europe, but Winn said the company doesn't see that as nearly enough to meet its decarbonization goals.

In part, he said, that's because the company's home country has limited interest in wind and solar.

"Unlike some parts of North America, renewable resources are hard in Japan. It's very mountainous. There's not a lot of uncovered land at the moment," he said.

So instead, the company is focusing on making its fuel cleaner by modifying natural gas plants to burn hydrogen, both in Japan and the U.S. That includes its Linden project in New Jersey, which will be modified to use up to 40% hydrogen.

Hydrogen could very well fit into the company's plans in New England as well, Winn said.

"We're looking at both blue and green hydrogen," he said. And he added that if the company can't make hydrogen for its plants locally, it can just bring it in from abroad. "We run a very large fleet of ships right now," he said.

Overall, Winn said, reliability is one of the company's main focuses, which was why it bought the Canal Generating Station in Sandwich, Mass., the bigger of its new purchases.

"For us, reliability and the low-carbon transition are tied together. And Canal was bought with that in mind," he said. "We can provide reliability to the market."

The company is also planning to offer up its newly acquired New England plants as possible interconnecting points for renewables. Canal could be a connection point for offshore wind coming off Cape Cod, and the Bucksport plant in Maine has an existing transmission interconnection that could link renewables to the grid, the company said in a recent separate press release.

"We are committed to transitioning the existing units to greener forms of energy as well as employing the attributes of the sites to enable renewable energy development in New England," JERA said. ■

The Bucksport Power Station, one of the natural gas plants recently purchased by JERA Americas | *JERA*

ISO-NE News

Avangrid Seeks to Terminate Commonwealth Wind PPAs

Developer Says Mass. Project Unfinanceable, Hopes to Submit New Bid

By John Cropley

Avangrid has moved to terminate power purchase agreements for Commonwealth Wind, a 1.2-GW offshore wind project it is developing in Massachusetts, saying the deals have become financially untenable and that the other parties refuse to renegotiate.

In the *dismissal motion* it submitted to the state Department of Public Utilities on Friday and in a public announcement, the company said it remains committed to Commonwealth Wind. But it said the project should be wrapped into the state's 2023 offshore wind power solicitation, at which point Avangrid could submit a bid that would be financially sustainable and proceed on a timetable that would meet the state's 2030 climate protection goals.

Avangrid said the bid it submitted in September 2021 and the PPAs it subsequently negotiated with three electric distribution companies (EDCs) in April 2022 were overtaken by factors including high inflation, sharply higher interest rates, the war in Ukraine and supply chain shortages.

On Oct. 20, Avangrid *asked the DPU* to put its review of the PPAs on hold for a month so it could renegotiate them. The three EDCs — Eversource Energy, National Grid and Unitil — *opposed this*, saying they had no intention of renegotiating.

Avangrid is seeking to halt review of power agreements for its 1.2-GW wind project off the coast of Massachusetts, saying the project cannot be financed as they are now written. | *Shutterstock*

Mayflower Wind Energy on Oct. 27 made a *similar request* to delay review of the PPAs for 400 MW of wind power it is developing off the Massachusetts coast.

The DPU *denied the requests* Nov. 4, saying the developers could move forward with the PPAs in place or move for dismissal, but not renegotiate them. Mayflower withdrew its request Nov. 7, saying it would continue with the PPAs and seek to resolve issues through conversation. It declined to comment Monday on its plans or the status of those talks.

But Avangrid on Nov. 14 said it would continue with the proceedings and seek ways to make Commonwealth financeable and economically viable. (See: *Mass. OSW Projects to Continue Through Regulatory Process*.)

On Friday, Avangrid moved for dismissal, saying the EDCs had refused to meet with it on the matter.

"No interest is advanced by approving PPAs that cannot and will not lead to the development of offshore wind energy generation," the company's attorneys wrote. "Instead, the commonwealth should conduct a robust fourth solicitation under Section 83C as soon as possible."

In its public statement Friday, Avangrid emphasized its commitment to clean energy in Massachusetts, including its 800-MW Vineyard Wind I project slated to come online late next year. It said it remained committed to Commonwealth Wind and was disappointed the EDCs had refused to discuss it.

The DPU is reviewing Avangrid's dismissal motion. Danielle Burney, spokesperson for the Massachusetts Executive Office of Energy and Environmental Affairs, which oversees DPU, said in an email that the offices of Gov. Charlie Baker and Lt. Gov. Karyn Polito were displeased with Avangrid's move.

"The Baker-Polito administration is disappointed by Avangrid's request to the Department of Public Utilities to dismiss the review of the Commonwealth Wind contracts," Burney wrote. "But [the administration] remains committed to the deployment of commercial-scale offshore wind and advancing clean, affordable energy on behalf of the Commonwealth's residents and businesses, while reducing greenhouse gas emissions and meeting the state's emissions goals, including achieving net zero in 2050." ■

MISO News

Entergy Strengthens its Emissions-reduction Goals

By Amanda Durish Cook

Entergy has fleshed out its interim goal of emission reductions by adding interim benchmarks and a definitive goal for 2050.

According to the company's latest *climate report* released last month, Entergy plans to reach net-zero greenhouse gas emissions from all electric and natural gas operations across its businesses by 2050. It aims to reduce owned and purchased emissions 50% from 2000 levels by 2030 and to have 50% carbon-free power generation capacity by 2030.

The utility's 2030 goals did not previously include a carbon-free capacity component and power purchases in its 50% utility-only, carbon-reduction goal. Entergy said it added the provisos because its planning models showed that it was on track to outperform its current goal.

It said it now expects to reach the current 2030 interim goal of reducing its CO_2 emission rate by 50% from its 2000 baseline several years early. "[We] are evolving this goal to include purchased power," Entergy said in the report.

The New Orleans-based company had only said it would strive for net-zero emissions in an addendum to its first climate report in 2019.

Entergy's goal is to reduce "emissions as low as possible and minimize our need to neutralize any residual emissions while still maintaining the reliability and affordability of our products, even as our customer base and demand for clean energy grows."

The utility said 2030's carbon-free capacity will be supplied by nuclear, solar, wind, hydropower and energy storage. It did not specify a definitive supply plan for 2050, saying its assumptions and risks will change over time.

Entergy completed the report's modeling before passage of the Infrastructure Investment and Jobs Act and the Inflation Reduction Act. It said the modeling doesn't account for the laws' potential acceleration of technological advancements and emissions goals.

However, Entergy noted that the laws are "expected to help us define our path to net-zero with more certainty, as well as enabling new and innovative solutions."

Rick Johnson, the company's director of sustainability, discussed the updated plan Dec. 12 during an Entergy Regional State Committee Working Group meeting.

He said while an uptick in demand might slow Entergy's emissions reductions, the utility is poised under several scenarios to limit its greenhouse gases in line with either a 2-degree or 1.5-degree Celsius total warming.

"We're going to continue to compare our path … to climate science to avoid the worst impacts," Johnson said. Entergy foresees "substantial growth in demand from electrification" that could lead to up to 60% more energy production by 2050, Johnson said, noting load growth could "put upward pressure on our absolute emissions."

"Some stakeholders might not be happy with individual company progress," he said. But he added that Entergy's subsidiaries are a linchpin in its region's decarbonization efforts.

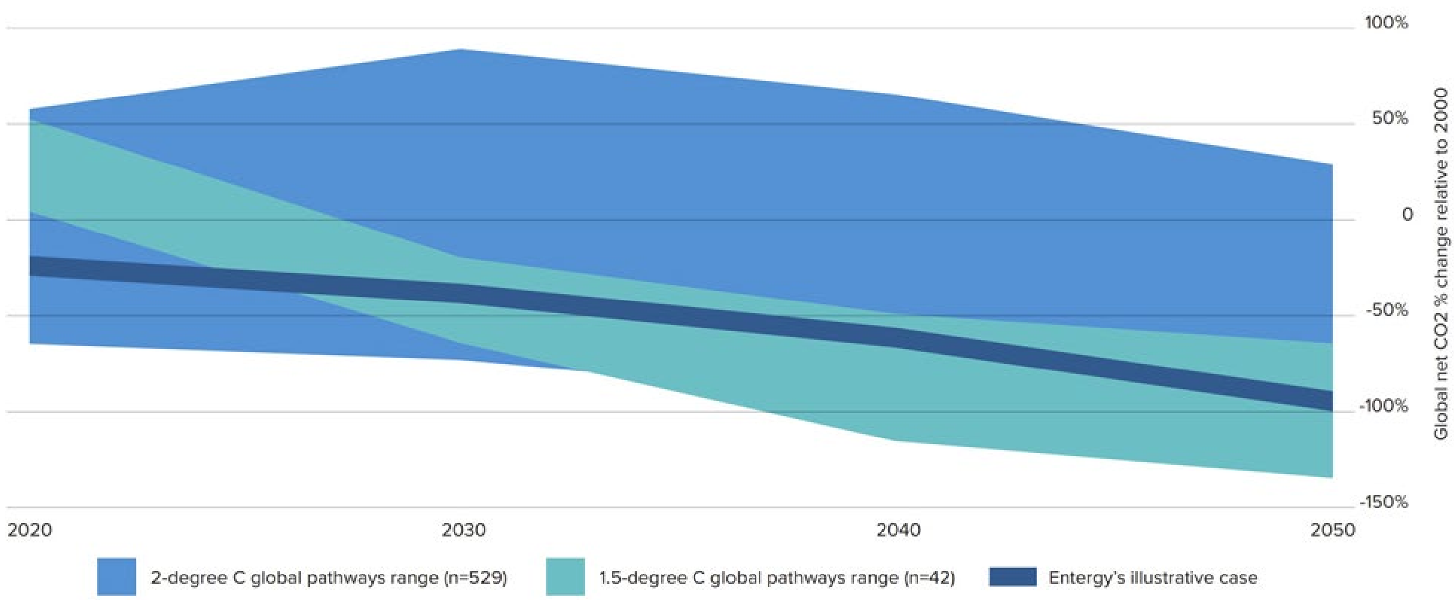
Johnson said Entergy is discussing whether to purchase carbon offsets but will likely only use them if it becomes necessary to counteract its remaining emissions.

"If we got to 2050, and we're short, yes, we'll look for high-quality, permanent instruments to neutralize those residuals," he said.

Johnson said he doesn't know when Entergy might next revise or update its climate goals, expressing hope that "this will go down to a lower number, but that's difficult to guarantee 28 years out."

Entergy needs clean, dispatchable generation including small modular nuclear reactors, advanced nuclear options, clean hydrogen, and long-duration storage to reach its overall emissions commitment, he said. Entergy believes some of those technologies may become commercially viable before 2035.

Going forward, any newly built Entergy gas facility will be hydrogen-capable and able to be retrofitted to exclusively burn hydrogen, Johnson said. He said Entergy's two newest



Entergy's illustrative pathway to net-zero compared to other climate warming scenarios | *Entergy*

MISO News

natural gas plants, the St. Charles and Montgomery power stations can co-fire up to 30% hydrogen.

Johnson added that Entergy Louisiana and Entergy New Orleans recently signed a memorandum of understanding with Diamond Offshore Wind *to explore the feasibility* of connecting offshore wind generation in the Gulf of Mexico to the grid. He also pointed to Entergy's recent *agreement* with Holtec International to evaluate installing small modular reactors in the Entergy service area.

Entergy will need some long-term transmission projects to prop up a clean energy future, Johnson said. He said Entergy "supports MISO's efforts to develop its initial proposal" for long-range transmission projects (LRTPs) and added that it will need to be confident that the projects have "demonstrable benefits that exceed the costs" and that costs are allocated in a fair manner.

MISO has mounted a series of four LRTP planning cycles but doesn't anticipate assessing Entergy's needs in MISO South until the third iteration. (See *MISO Staff Preview New LRTP Projects with Board*.) ■

Entergy solar generation in New Orleans | *Entergy*

MISO News

MISO, SPP Unable to Find Smaller Joint Tx Projects

By Amanda Durish Cook

| © RTO Insider LLC

MISO and SPP officially announced last week that they will not pursue any small, congestion-relieving interregional projects from their first Targeted Market Efficiency Project (TMEP) study.

The two grid operators have been hinting that they likely weren't going to land on any beneficial projects. (See *Search for Small SPP-MISO Interregional Projects May be Fruitless*.)

SPP's Neil Robertson said the constrained flowgates under study either already had a solution from SPP's regional planning, resulted in projects with one-sided benefits, or the proposed projects were too costly for one RTO when compared to continued congestion payments.

Robertson said during an Interregional Planning Stakeholder Advisory Committee (IPSAC) teleconference Wednesday that the RTOs' Joint Targeted Interconnection Queue (JTIQ) study stands to ease congestion on some of the TMEP candidate constraints. He said staffs assumed that the approximately $1 billion of JTIQ projects took precedence over potential TMEP projects. (See *Stakeholders Not Sold on JTIQ Projects' Cost-Sharing Plan*.)

Robertson said the TMEP study contained multiple constraints where "other study processes got there first."

"In this particular case, we're a victim of timing and circumstance to some extent," he said.

As an example, Robertson said a possible $37.7 million rebuild of a 50-mile, 161-kV line near the Oklahoma-Arkansas border would nearly double the TMEP cost cap of $20 million.

The grid operators screened for possible TMEPs when a market-to-market flowgate amassed $1 million or more in congestion costs over a two-year period. The two *catalogued* seven permanent flowgates that racked up between $10 million and $43 million worth of congestion. (See *MISO, SPP Hunt for Small Interregional Tx Projects*.)

This is the fifth straight time MISO and SPP have returned empty-handed after an interregional study.

Despite coming up empty, the RTOs are memorializing their TMEP process in their joint operating agreement and will launch another study in the future. They will also create separate regional cost-allocation methods to use when they find a beneficial project.

"I think [with] the fact that TMEPs will be a tool in the future, I think it's inevitable that we will have multiple projects in the coming years," Robertson predicted.

Advanced Power Alliance's Steve Gaw said he was frustrated with the results. He said it seemed that MISO and SPP are hamstrung by siloed joint planning processes, perpetually promising projects "on the horizon" that never materialize.

"We're still missing the mark here in terms of our interregional planning processes," Clean Grid Alliance's Natalie McIntire said.

The RTOs have proposed that TMEPs must cost $20 million or less, must not be greenfield projects, be in service by the third summer peak from their approval, and completely cover their installed capital cost within four years of service through avoided congestion.

They borrowed many of their standards from MISO and PJM's TMEP criteria. Stakeholders on both sides of the seam have said the cost threshold should be increased, given today's high inflation environment and tight labor market.

They asked how the RTOs settled on the TMEPs' cost threshold. Some said the $20 million limit established by PJM and MISO in 2017 amounts to $30 million in 2022 dollars. Their staffs responded that the $20 million cap ensures that projects are low-risk, relatively easy to complete and don't impede on other more intensive interregional planning.

During a November common seams initiative meeting between the two grid operators, McIntire said it would be a "tragedy" if they emerged from another interregional study without a single project recommendation.

MISO and SPP are continuing to determine how a transmission owner in one footprint can finance and construct lines in the neighboring RTO without benefits to the region where the transmission would be located.

Currently, the MISO-SPP operating agreement doesn't contemplate construction of a cross-border project unless at least 5% of the project investment stands to benefit the neighboring region. The RTOs are attempting to chart a path where a TO can construct a project that solely benefits the RTO across the border. ■

MISO News

MISO, PJM Staffs Endorse 1 TMEP Joint Project

MISO and PJM have endorsed one small interregional project this year after their Targeted Market Efficiency Project (TMEP) study.

The grid operators said they will pursue $200,000 of line work on the Powerton-Towerline 138-kV flowgate in central Illinois. The project is expected to yield $1.8 million in annual congestion savings benefits; PJM is projected to realize about 72% of the savings benefits and MISO 28%.

The project is one of two that survived a final round of analysis. The RTOs also considered an upgrade to a congested 138-kV flowgate near Chicago. (See *MISO, PJM Down to 2 Possible TMEPs*.)

PJM's Nick Dumitriu said during a MISO-PJM Interregional Planning Stakeholder Advisory Committee meeting Thursday that the Chicago constraint's congestion is not persistent enough to proceed with a project. He said staffs' additional analysis confirmed that a significant part of the flowgate's historical congestion is caused by neighboring outages.

Both RTOs will recommend early next year that their respective boards approve the Powerton-Towerline project. The project must be in service no later than June 1, 2025.

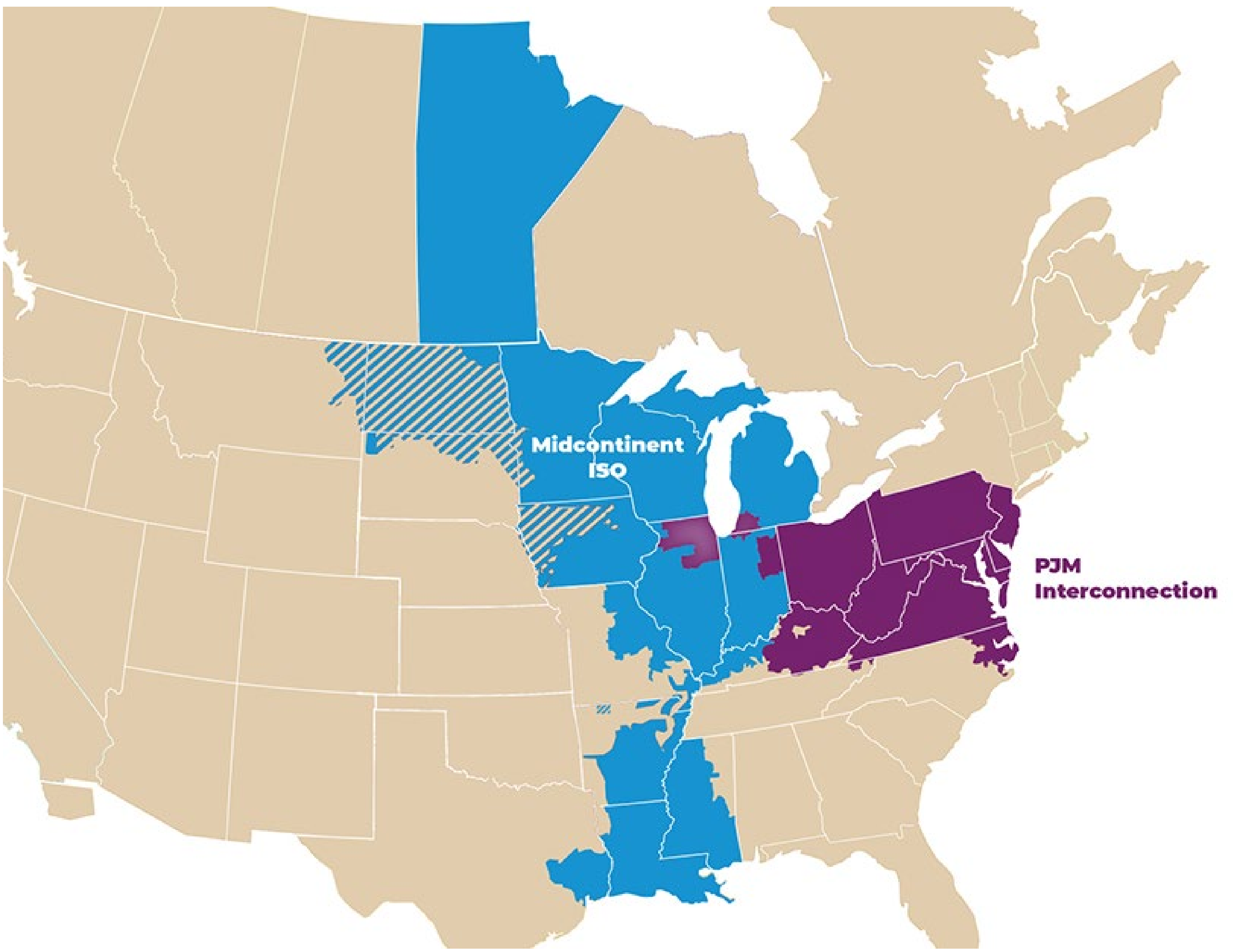
The grid operators require TMEPs cost $20 million or less, be in service by the third summer peak from approval and must completely cover installed capital costs within four years through congestion benefits.

MISO and PJM studied about $328 million of congestion from 2020-2021 in this year's TMEP process. They originally identified 23 flowgate candidates that might benefit from a TMEP project and reviewed potential problem spots for interregional solutions.

Clean Grid Alliance's Natalie McIntire asked that the RTOs consider raising the $20 million cost threshold to increase the chances for other potential projects.

"There's certainly been a significant amount of inflation and overall cost increases," McIntire said. ■

— Amanda Durish Cook



| ISO/RTO Council

FERC Again Prohibits MISO TOs from Financing Merchant Upgrades

Commission Upholds Ruling Against Self-funding HVDC Lines

By Amanda Durish Cook

FERC last week upheld its prior ruling blocking MISO transmission owners from self-funding network upgrades for merchant HVDC transmission lines.

The commission affirmed in its Friday order a decision issued in the spring that the self-funding option cannot be extended to merchant upgrades because their developers aren't offered the same range of financing options as transmission owners under certain circumstances (*ER22-477-002*). (See *FERC Blocks MISO Self-fund Rule for Merchant HVDC Line Upgrades*.)

FERC rejected arguments from MISO, its transmission owners and ITC Midwest that merchant HVDC developers and generation developers are interchangeable because they both require upgrades to the system for their projects.

The commission again emphasized that MISO doesn't include an option to build or liquidate damage provisions in interconnection agreements for merchant HVDC developers without injection rights or a precertification from MISO that its system can handle the capacity and energy the line plans to deliver. The grid operator allows merchant HVDC lines to connect to the system without injection rights, but those lines are considered non-firm and the upgrades are classified as necessary upgrades instead of network upgrades.

MISO, TOs and ITC argued that necessary upgrades for HVDC lines are similar to the RTO's other network upgrades, where the owners have the right to finance the upgrades before the interconnection customers are offered the chance.

"The thrust of MISO and MISO Transmission Owners' and ITC Midwest's argument on rehearing is that these two sets of customers are effectively indistinguishable, but neither grapples with how, then, MISO's proposal to afford options to control risk and certainty during the design and construction process to only one set of customers is just and reasonable and not unduly discriminatory," FERC wrote.

The commission said MISO's case for applying initial funding to merchant HVDC lines "does not alter the fact that MHVDC connection customers with necessary upgrades are distinct because, unlike interconnection customers and MHVDC connection customers with network upgrades in MISO, they lack injection rights and are subject to different study requirements."

Commissioner James Danly again protested the decision, as he did when it first came before FERC. He repeated a dissent that the decision denies "transmission owners' right to receive a return on and of the capital costs of network upgrades, necessary upgrades and transmission owner system protection facilities."

Commissioner Mark Christie separately concurred, contending that merchant developers are on equal footing with generation developers in RTOs. He said they should both pay the full "but for" costs of interconnection, including network upgrades.

"When … a generation developer or a merchant transmission line developer pays the full costs of its interconnection, it is the developer incurring a cost of capital, not the transmission owner," he wrote. "Allowing the transmission owner a profit on someone else's capital investment would be an unearned windfall. When the transmission owner incurs operations and maintenance costs associated with the upgrade, the transmission owner can seek cost recovery in compliance with applicable utility accounting rules or other acceptable procedures."

The latest decision on HVDC self-funding is connected to a larger, still-unfolding saga over who has the right to finance line upgrades in MISO.

MISO reinstated TOs' right to self-fund network upgrades necessary for new generation at the direction of a 2019 FERC order. The decision has been a hot-button issue, spawning three years' worth of reopened contracts, refunds to interconnection customers, interconnection agreements left unexecuted in protest, and condemnation from FERC Chairman Richard Glick. (See *FERC Upholds MISO Self-fund Order, Glick Dissents*.)

The D.C. Circuit Court of Appeals in November *ruled* that FERC did not adequately explain why it recently reinstated transmission owners' option to self-fund. It remanded the case back to the commission. (See *FERC Must Clarify MISO Tx Funding Decision, DC Circuit Finds*.)

MISO has revised various interconnection agreements for TOs who wanted to have first crack at network upgrades' initial funding. (See *FERC Accepts Documents in MISO TOs' Self-fund Selection*.) ■

Buried HVDC cables in a highway right of way (Italy-France Interconnector) | *Roda S.p.A.*

FERC Upholds MISO's Cost Allocation for LRTPs

By Amanda Durish Cook

FERC continues to sanction MISO's separate-but-equal postage stamp rate that is divided between its Midwest and South regions for major transmission buildout.

The commission rejected rehearing requests with an order Friday that keeps MISO's subregional cost-allocation method for long-range transmission planning (LRTP) projects in place (*ER22-995-001*).

FERC said it continues to believe that it's appropriate for the RTO to allocate project costs "broadly within a single subregion rather than solely on a systemwide basis."

MISO is using a FERC-approved 100% postage stamp to load rate for the first two cycles of projects coming out of its LRTP studies. The costs are confined to the grid operator's Midwest region, where the projects are physically located. (See *FERC OKs MISO's Bifurcated Cost-allocation Tx Design*.)

When the RTO begins addressing needs in its South region during the final two LRTP portfolios' work, it said it might use a new, more specific cost-allocation design that accounts for more beneficiaries. (See "Zeroing in on Cost Allocation," *'Conceptual' Tx Planning Map Troubles MISO Members*.)

MISO has already approved $10 billion in projects with its first LRTP portfolio. It may recommend up to $30 billion of work as part of its second portfolio.

Sequestering MISO Midwest from MISO South continues a transmission-planning tactic that staff has used since integrating the South in 2013. Through separate cost-allocation treatment and study deferrals, MISO shields its South region from footprint-wide system planning and allocation impacts.

American Municipal Power (AMP) and MISO's industrial customers said FERC blindly accepted a "crude" cost allocation method that isn't supported by analysis and will require transmission customers to foot steep bills, even when a project benefits a neighboring RTO. They argued that the commission neglected its duty to independently assess the rate proposal and said MISO failed to devise a more precise allocation when it had the means to do so.

The intervenors said FERC was wrong to characterize the new LRTP cost allocation as essentially the one used for 2011's Multi-Value Project (MVP) portfolio with only "limited" changes. AMP argued there's a "fundamental distinction between regional and subregional planning and cost allocation." The MVP portfolio was allocated systemwide with a postage stamp rate in 2011, when the footprint didn't extend beyond southern Missouri.

The industrial customers said that FERC "cannot transfer its duties to the RTO stakeholder process or assume that state regulatory support or majority support in the RTO stakeholder process indicates widespread consumer satisfaction or provides evidentiary support for a just and reasonable rate outcome."

They also said that the "promise of a more granular cost allocation for future LRTP projects does not justify acceptance of an allocation of over $10 billion in costs that are not sufficiently tied to roughly commensurate project benefits."

Xcel Energy insulator replacement work in Northern Minnesota | *Xcel Energy*

MISO's first LRTP portfolio alone could raise costs by as much as $2.80/MWh, the customers said.

They also contended that MISO relied on "stale" data to back up its allocation design. The RTO used a Brattle Group analysis that showed the 2011 MVP projects' benefits were overwhelmingly confined to the Midwest region. The consulting firm said that benefits' spread will likely continue unless MISO secures more transfer capability between the subregions. (See "Brattle: South Benefits Unlikely from Midwest," *MISO Finalizes Long-range Tx Cost Sharing Plan*.)

FERC said that MISO was not required to "re-justify the MVP category from scratch," nor was it required to "analyze the data from future LRTP portfolios." The commission pointed out that courts have repeatedly found that a rate should be reasonable, not that it should be "the most reasonable or the best one out of possible alternatives."

"It is not unduly discriminatory for the [c]ommission to accept a subregional option while MISO continues to discuss with stakeholders a different approach for future projects," FERC said. "Therefore, arguments concerning future cost allocation method filings are premature."

The commission said MISO's LRTP allocation divvies costs on a "basis that is at least roughly commensurate with the estimated benefits" and was the product of "an extensive, multi-year stakeholder process." It also defended the Brattle analysis, highlighting its "large data set of 16 actual — not just proposed — projects."

It said industrial customers' request to allocate costs to customers outside of MISO is beyond the scope of the order.

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

Commissioners James Danly and Mark Christie agreed with the order in short concurrences. Danly said although he had misgivings over the postage stamp method in general, he could not say definitively that its use is unfair. ■

NYISO News

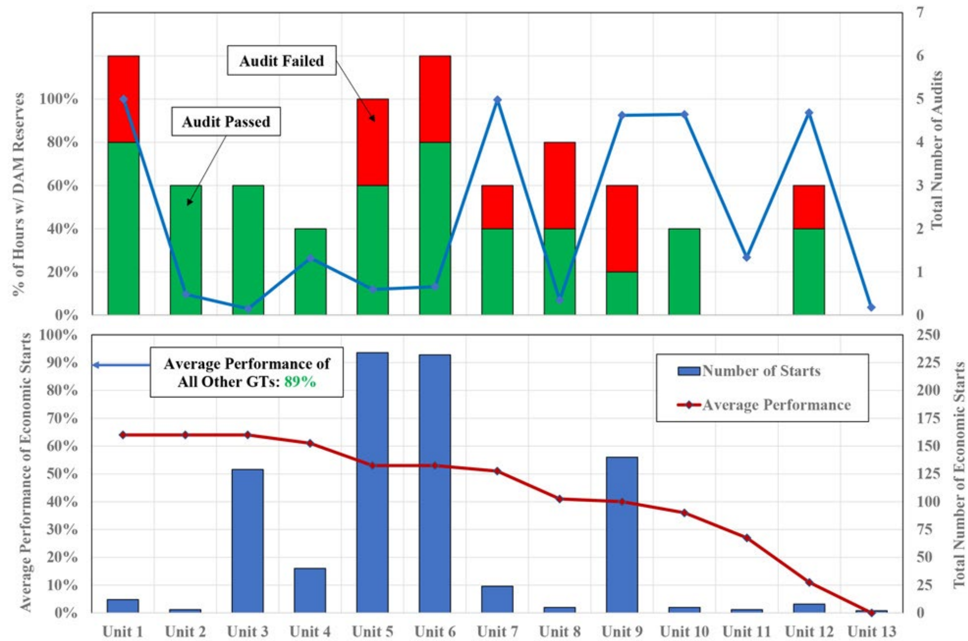
NYISO Over-crediting Poorly Performing Units' Capacity, Monitor Says

By John Norris

NYISO is qualifying generation units for meeting their reserve requirements even though they fail to provide adequate reserves during normal market operations, the ISO's Market Monitoring Unit told stakeholders last week.

Speaking to the Installed Capacity/Market Issues Working Group on Dec. 13, Potomac Economics' Pallas LeeVanSchaick said NYISO is using capacity accreditation rules that may be awarding excessive accreditation to several gas generators. The ISO should re-evaluate its reserve auditing procedures for gas turbines to be more responsive to normal market operations and improve capacity accreditation test requirements to account for peak summer conditions, he said.

The Monitor's third-quarter *report* on the NYISO markets, released last month, found that the ISO is conducting more 10- and 30-minute non-synchronous reserve pick-up (RPU) audits but has failed to disqualify gas turbines that performed poorly.



Gas turbine audits showed an inability to accommodate normal reserve requirements. | *Potomac Economics*

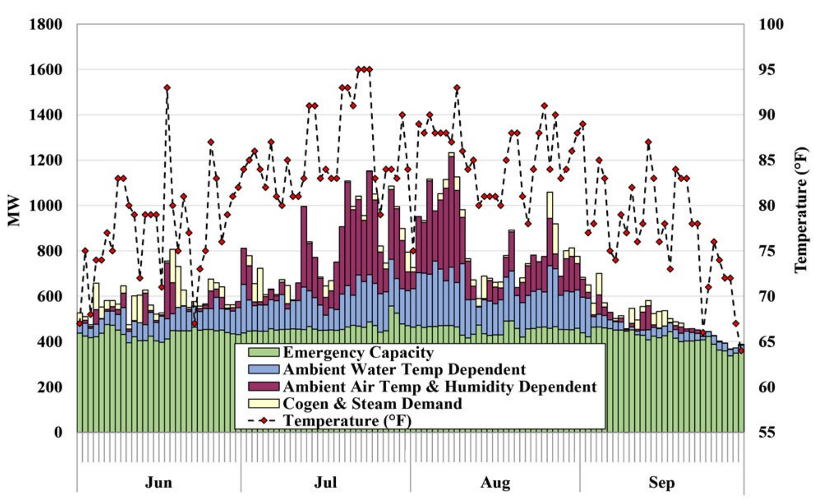
Potomac studied the 13 worst performing gas turbines; despite many of them being consistently used by the ISO, they regularly fail to achieve performance levels even close to the 89% average of all other gas turbines.

Kevin Lang, partner at Couch White, asked why Potomac believed the ISO was not acting on generators that had performed poorly in audits.

LeeVanSchaick responded that "NYISO has the authority to do that … but it is not clear to us why they have not been disqualified." Potomac will "monitor this because there's inefficiency in continuing to compensate resources for providing reserves when they cannot perform."

According to the report, on days when peak load surpasses 28 GW, an average of about 1,060 MW of installed capacity from fossil fuel and nuclear generators was functionally unavailable during the quarter because of above-average temperatures.

Emergency generators dispatched by NYISO during peak load may overestimate their available capacity and receive improper accreditation because these units' dependable maximum net capability (DMNC) tests, which calculate the gross sustained net output of a generator, fail to capture ambient water temperatures, LeeVanSchaick said.



Functionally unavailable capacity from generators during peak conditions | *Potomac Economics*

The audit results suggest "that there is a tendency to over-credit resources that are impacted by ambient conditions," he said. On peak summer days, "there is capacity that, although qualified, is not as effective as other capacity in terms of providing reliability," meaning "some units are going to be less available at peak times."

Howard Fromer, who represents the Bayonne Energy Center, asked whether Potomac had begun discussions with NYISO to adjust capacity accreditation procedures or rules for the impacted resources.

LeeVanSchaick said that Potomac "certainty recommends NYISO looks at these categories in the context of capacity accreditation efforts." (See "Capacity Accreditation," *NYISO Justifies Unpopular 10-kW DER Aggregation Min. Requirement*.)

NYISO energy markets were competitive throughout the quarter, according to the report. Energy prices increased across all zones because of both higher congestion in the Central-East interface and emissions costs, and capacity prices fell because of lower installed reserve margins and peak load forecasts, which helped offset increased spot prices. ■

NYISO News

FERC OKs Sale of NY Power Plant to Crypto Miner

State Moratorium in Effect, but Company Plans Fuel Conversion

By John Cropley

FERC last week granted a cryptocurrency mining company approval to buy a 60-MW gas-fired power plant near Buffalo, N.Y., where it has been running some of its operations (*EC22-78*).

FERC ruled that there was nothing within the parameters of its review that would block the sale. The New York state Public Service Commission reached the same conclusion in September.

Crypto mining has been under fire in New York for the carbon footprint of its huge electrical demand, and the state recently placed a two-year moratorium on permits for carbon-fueled operations. That first-in-the-nation move does not halt existing operations. (See: *NY Slaps Moratorium on Certain Crypto Mining Permits*)

The crypto operation at the Fortistar North Tonawanda (FNT) plant has been the target of noise and environmental complaints, although it also has supporters, as do other mining operations in the economically stagnant upstate region.

A subsidiary of *Digihost Technology* (Nasdaq:DGHI) seeks to buy FNT from its parent entities. In regulatory filings, it said there would be no change in the day-to-day operations after the purchase. The same company running it under contract since 2002 would continue to operate it, and it would sell to the wholesale power market whatever electrical output it does not use for on-site crypto operations.

The thermal output of the co-generation plant has, in the past, been shipped to a greenhouse complex via a 2.5-mile steam pipe but that had ceased at the time of application.

The 133 comments on the purchase submitted to the state PSC ranged from support because of economic benefits to opposition because of emissions.

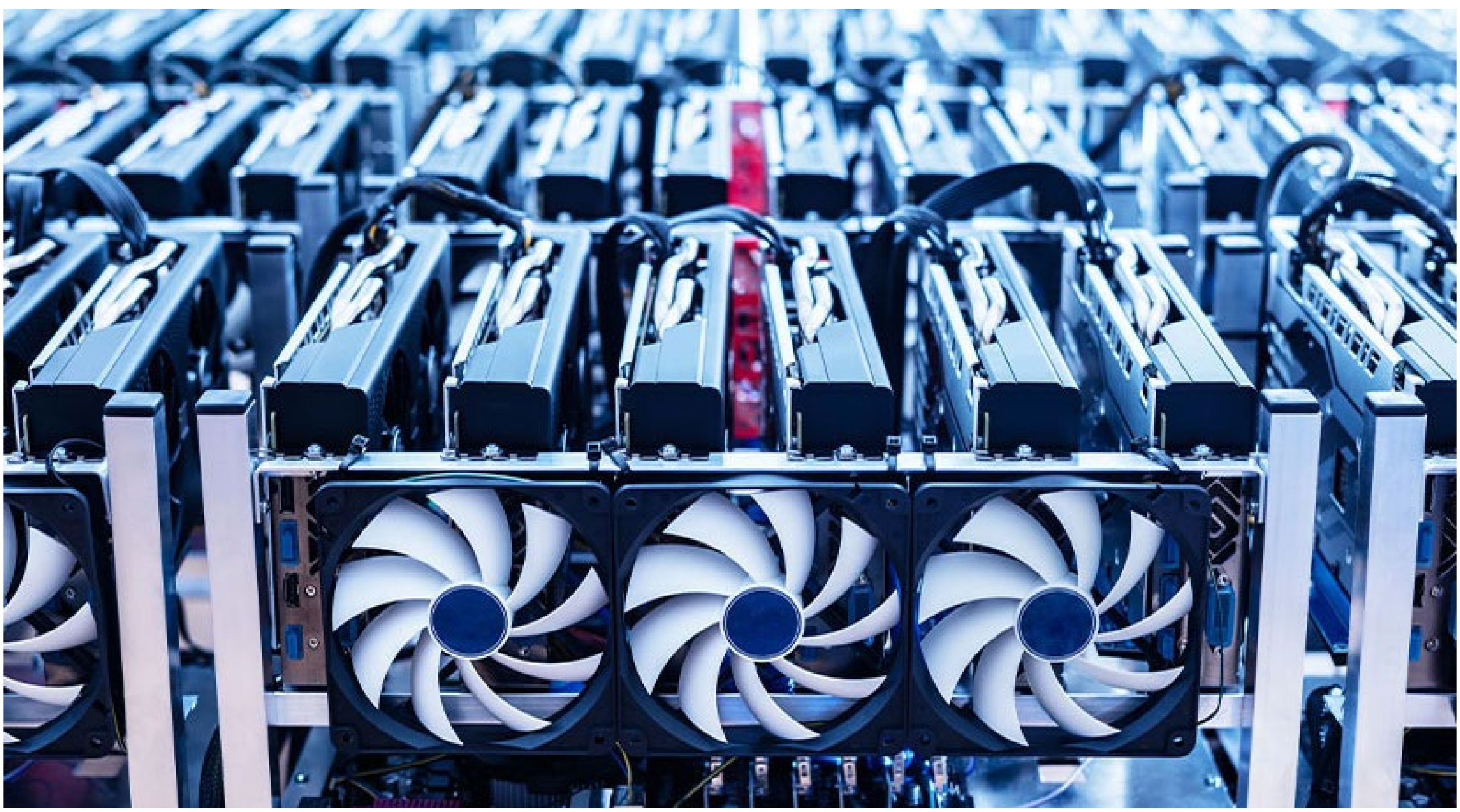
In response to critical comments during the state review, Digihost said it intended to convert the plant to run on renewable natural gas and then hydrogen. It said this would make it entirely powered by zero-emissions sources by the 2025, and thereby compliant with New York state's increasingly stringent climate protection laws.

In its *Sept. 15 ruling*, the PSC said environmental concerns were beyond the scope of its limited review. It could only look at whether the transaction would create an opportunity to exercise horizontal or vertical market power, or would create potential to harm ratepayers. It would not, six of the seven the commissioners said, and therefore the PSC would not undertake an expanded review.

FERC authorized the transaction, finding no impact on horizontal or vertical competition, no adverse impact on rates, no impairment of regulation and no cross-subsidization.

An attorney representing Digihost in the regulatory process declined to comment on the matter Friday.

An update issued by the company Dec. 2 indicated it expected the sale to close in the first quarter of 2023. ■



A cryptocurrency mining company is set to buy a gas-fired co-generation plant near Buffalo, N.Y., to power some of its operation. | *Shutterstock*

NYISO News

NYISO Capacity Accreditation Implementation Worries Stakeholders

BIC Recommends Proposed Hybrid Aggregated Storage Models

By John Norris

RENSSELAER, N.Y. — NYISO stakeholders last week expressed reluctance to approve the ISO's *proposed* implementation of its new capacity accreditation construct, with some saying they did not fully understand all of the changes and others saying it would be applied unequally.

The proposed revisions include the implementation details and technical specifications necessary for establishing capacity accreditation factors (CAFs) and capacity accreditation resource classes (CARCs), such as updated calculations for translation factors, demand curves and resource-specific derating factors.

Although the proposed revisions were ultimately approved, several stakeholders at the Business Issues Committee meeting Wednesday opposed the motions emphatically.

Jay Goodman, an attorney with Couch White, said his clients don't oppose the capacity accreditation project outright but are "concerned with committing to implement it by May 1, 2024," because it "will not be applied equally and accurately to all capacity providers at that time."

Goodman said that they "perceive the capacity accreditation process as a work in progress" and that "numerous outstanding issues should be addressed or resolved prior to this vote taking place."

They are also concerned that all thermal units will be treated as a single CARC, despite them having a "diversity of operating characteristics," he said.

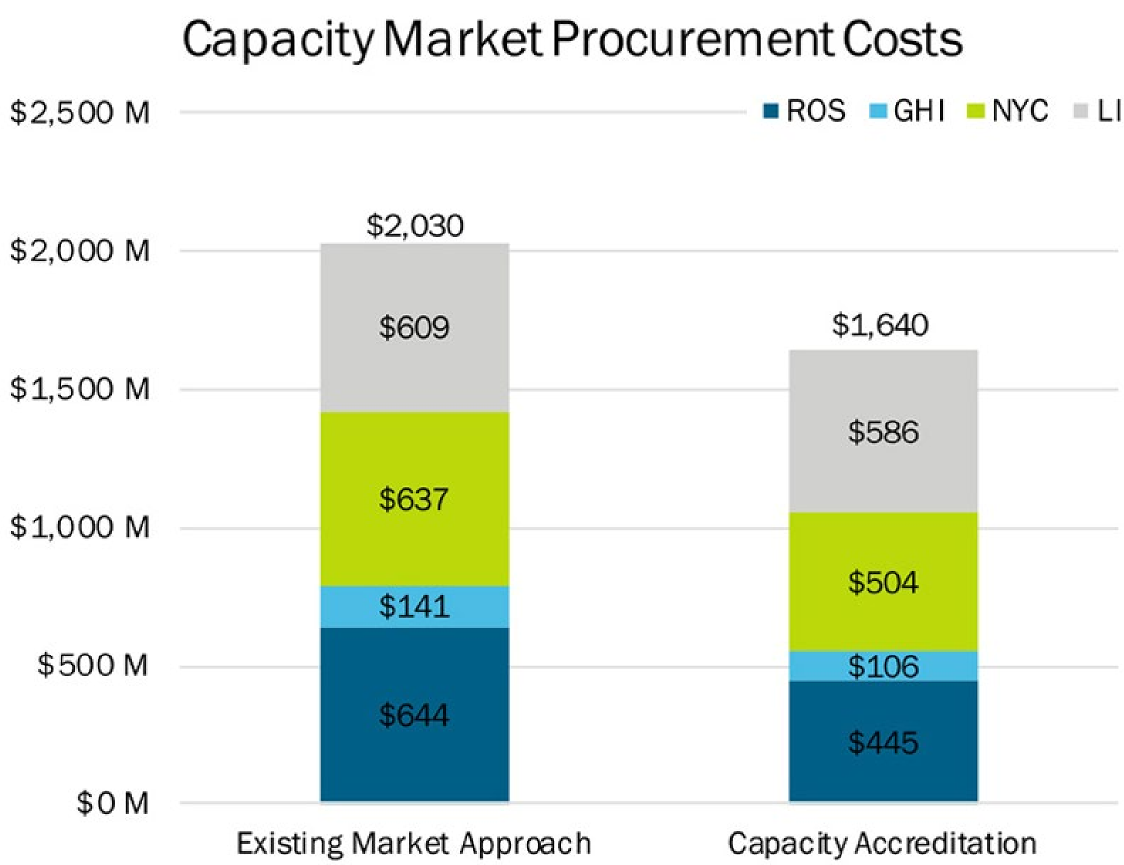
Daymark Energy Advisors CEO Marc Montalvo, representing the Utility Intervention Unit, explained that his abstention was "not because of a lack of faith in the ISO or the quality of their work" but "as much as a timing issue," as well as a "feeling that [stakeholders] do not yet have a complete understanding of all the moving parts."

Adam Evans, a staffer at the New York Department of Public Service, asked that "if there is remaining work that needs to done, then why would it not be included in what folks are voting on today?"

Doreen Saia, an attorney with Greenberg Traurig, recommended that NYISO edit the motion to avoid this "devolving into conversation about project prioritization" and alleviate concerns raised by stakeholders.

With guidance from Saia, NYISO then edited the motion recommending approval by the Management Committee and Board of Directors to say that the ISO is committed to addressing the capacity accreditation work plan as presented and any associated enhancements as necessary.

The proposed revisions now go to the MC this Wednesday. NYISO anticipates filing the summary of the final capacity accreditation implementation details with FERC within 90 days of MC approval.



Capacity accreditation program saves $390 million in capacity market procurement costs | *NYISO*

Aggregated Hybrid Storage

The BIC also voted to recommend that the MC approve NYISO's *proposed* tariff modifications that support the market participation of aggregated hybrid storage resources (HSR), generators co-located with storage resources that are all behind a single point of injection.

The changes would incentivize developers to couple generators with storage resources and, also, update the co-located storage resources (CSR) to allow for additional use cases, such as limited run-of-river hydro or landfill gas.

NYISO is targeting the third quarter of 2023 to file tariff modifications with FERC, anticipates making necessary software design updates throughout 2023 and plans on fully implementing the changes in 2025. ■

NYISO Operating Committee Briefs

RENSSELAER, N.Y. — NYISO's Operating Committee on Thursday approved a winter study, tariff revisions to improve transmission study coordination within the interconnection process, manual updates for "internal controllable" lines (ICLs) and a winter operations study that included new nameplate values for energy storage.

Con Ed Study

The committee approved compliance procedures presented by Consolidated Edison that verified loss-of-gas and minimum oil burn requirements for the winter, which found that there was no change in the results from last year.

Con Ed said it should be able to provide New York City with energy during peak load conditions and meet NYISO reliability requirements using the same expected number of generators as the last winter capability period.

Dan Head, senior engineer at Con Ed, summarized the findings saying, "This year should look like last year."

Interconnection & Transmission

The OC voted to recommend that the Management Committee and Board of Directors authorize NYISO staff to file proposed tariff revisions that revise base case inclusion rules used in interconnection studies, as well as enhance coordination between transmission project and class year project studies.

The proposals build upon NYISO's efforts to improve the interconnection process. (See *NYISO Investigating Tariff Changes to Improve Interconnection Processes*.) The ISO will request an effective date of 60 days from when the proposal is filed with FERC.

'Internal Controllable' Lines

Stakeholders voted to approve manual revisions to clarify how ICLs will be evaluated with respect to both existing interface definitions and dispatch assumptions.

The updates, which were approved by both the OC on Thursday and the Business Issues Committee the day before, are part of a raft of revisions to the ICL design that have been proceeding on an accelerated timeline so that they can be adopted for the 2023 Class Year. (See "Deliverability Rules," *NYISO Management Committee Briefs: Nov. 30, 2022*.)

Winter Operations Highlights

The committee approved NYISO's 2022 winter operations report, which reinforced the New York-to-New England interface loop-flow concerns raised by the Market Monitoring Unit. (See related story, *NYISO Over-crediting Poorly Performing Units' Capacity, Monitor Says*.)

NYISO also shared an updated total nameplate value of installed intermittent resources in the New York Control Area, which, for the first time, included energy storage resources:

- storage: 20 MW
- behind-the-meter solar: 4,184 MW (+61 MW)
- front-of-the-meter solar: 94 MW (+20 MW)

(See "Intermittent Resources Update," *NY TOs Seek Clarification on ROFR for Upgrades*.)

Class Year 2021

Thinh Nguyen, senior manager of interconnection projects, told stakeholders that the second round of Class Year 2021 projects had been *posted* and that developers must now post their security by Dec. 21.

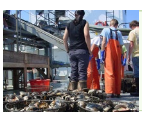
Assuming all security is posted on time, the next class year will start on Jan. 23, 2023.

Nguyen also said that NYISO will be hosting a Class Year Entry Forum this Wednesday for stakeholders to learn more about the process and procedures related to the class year study. Email *InterconnectionSupport@nyiso.com* to learn more. ■

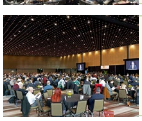
— John Norris

Northeast news from our other channels

New York CAC Debates Inclusion of Blue Hydrogen, Union Jobs in Plan

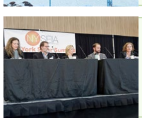


Northeastern States Plan OSW Compensation Fund for Fisheries

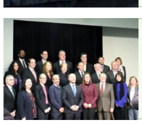


NY Solar Developers Look to Soar on Policy, Funding 'Tailwinds'

NYSERDA Gets Funding Boost as Energy Transition Continues



Solar Industry Challenged by NY Home Rule



New York Climate Scoping Plan OKd

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

PJM News

Synchronized Reserve Prices Fall in PJM Markets After Overhaul

By Devin Leith-Yessian

Synchronized reserves have seen a drop in prices since PJM implemented market overhauls at the start of October, the RTO says.

According to a *presentation* given during the Market Implementation Committee's meeting Dec. 7, the average clearing price in both the day-ahead and real-time markets was less than $2/MWh for the first two months of the new market rules. In October, the day-ahead prices were $0 for over 95% of the hours, while in November that lowered to 87%.

The presentation said the "significantly reduced" prices are believed to be caused by the lowering of the offer cap from $7.50/MWh to 2 cents, and by the must-offer requirement expanding the pool of resources providing synchronized reserve services. In the real-time market, prices were at or below 2 cents for about 72% of the hours in September, prior to the changes being implemented, while that share climbed to 96% in October.

The changes, approved by FERC in May 2020, aligned the day-ahead and real-time market products with the aim of eliminating the practice of PJM having to go out-of-market to procure reserves. Both the commission and PJM indicated then that they believed the changes would lead to increased pricing. (See *FERC Approves PJM Reserve Market Overhaul*.)

The commission partially reversed its previous order in January, saying that changes it had made to PJM's operating reserve demand curve (ORDC) were a mistake. The downward sloping ORDC approved by FERC in 2020 would have allowed LMPs to exceed $12,050 during extreme shortages. (See *FERC Reverses Itself on PJM Reserve Market Changes*.)

Dana Guernsey, co-founder of distributed energy resource provider Voltus, said the price fall appears to have caught most by surprise. While she said two months of data are still not enough to be sure of the impact, if the lowered prices persist, they may not provide the appropriate incentives for some resources to continue to provide reserves.

"PJM set out to reform their market to accurately reflect the reliability value of reserves, but the prices we're seeing do not actually create efficient market signals … at a time when reserves are more and more important," she said.

She noted that a 2018 *price formation paper* published by PJM explained the stated focus of the changes was to enhance the reserve markets "by more directly aligning the reliability value of reserves with the clearing price for them and strengthening incentives for performance when reserves are deployed."

Ken Schisler, CPower Energy senior vice president of regulatory affairs, agreed that the scale of the price fall was more significant than expected.

Electric school buses are being deployed as distributed energy resources when they are not running. DER providers are concerned that a recent fall in the value of synchronized reserves in the PJM markets could reduce the incentive for DER companies to continue providing the service. | *© RTO Insider LLC*

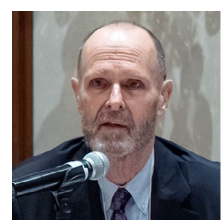
"The drop in pricing is deeper than many at PJM and in the industry anticipated. We are keeping an eye on pricing, and in the meantime we are evolving our portfolio and market participation based upon the price signals the market is sending us," he said.

Throughout the discussion of how the changes were expected to function once live in the markets, it was imagined that they would likely lead to prices increasing. Guernsey hypothesized that FERC revisiting its 2020 order and removing the ORDC provisions, but leaving the rest of PJM's proposal, may have distorted the intent and functionality of the changes.

"Maybe the original price formation proposal got edited so many times along the way that now we're seeing unintended consequences," Guernsey said. "It seems like the original goals not only were not accomplished, but we might even be seeing the opposite effect take hold."

She suggested that PJM consider increasing the offer cap above the newly adopted 2-cent maximum.

"The offer cap is meant to reflect the expected value of the penalty for failing to provide synchronized reserves. I don't understand how a 2-cent penalty is a healthy market signal if the goal is reliable reserve resources," she said.



Monitoring Analytics President Joe Bowring | *© RTO Insider LLC*

Independent Market Monitor Joe Bowring said that, based on the data to date, the market prices appear to be the result of market fundamentals; supply increased significantly and prices decreased. Bowring said he does not believe the price decline will have an overall significant impact on demand response providers, as more than 95% of their revenues are derived from the capacity market.

Increasing prices is not the goal of the market design, and higher prices are not by definition more efficient, Bowring said; prices should reflect the actual supply and demand of reserves.

He said that there is no evidence that the price decrease was a result of removing the $7.50 adder and also argued that the previous adder was not accurate.

"The $7.50 was always an incorrect number. There was never a logical basis for the markup. It wasn't based on costs," he said. ■

PJM News

FERC Orders Two Ohio Utilities Ineligible for RTO Adder

By Devin Leith-Yessian

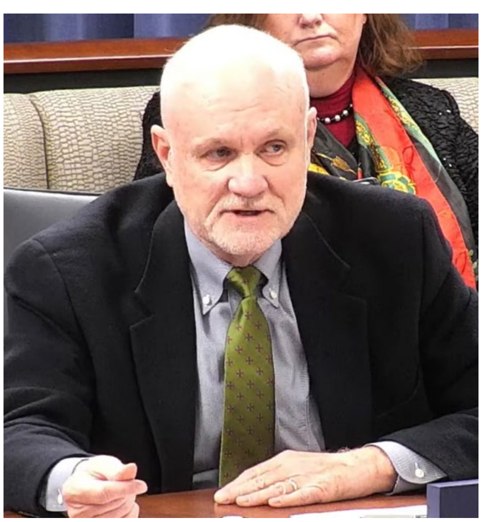
FERC rescinded RTO participation incentives for two American Electric Power affiliates last week on the grounds that Ohio law compels transmission owners to participate in an RTO (*EL22-34*).

The Ohio Consumers' Counsel (OCC) argued in a Feb. 24, 2022, *protest* that AEP's Ohio Power Co. and AEP Ohio Transmission Co., both PJM members, should not be permitted to continue charging a 50 basis point adder to their authorized return on equity (ROE). The commission agreed with the OCC that past commission orders have established a "voluntariness" requirement — that the adders are an incentive to join and remain members of transmission organizations and not applicable where state law requires participation.

However, the commission rejected the OCC's challenge of RTO adders for FirstEnergy's American Transmission Systems, Inc. (ATSI) and Duke Energy Ohio.

In its Dec. 15 order, the commission found that since both ATSI and Duke Energy Ohio reached their rates through integrated settlement packages — rather than having adders directly authorized by the commission — it would require evidence that the companies' overall ROE is unjust and unreasonable for it to consider ordering changes.

"We do not know the precise trade-offs and concessions made by parties to those proceedings during the settlement process and the terms to which and conditions to which those parties would have agreed with respect to Ohio transmission assets had the commission policy on RTO adders been different. As such, we do not find it would be appropriate to change unilaterally a single aspect of such a comprehensive settlement," the commission said.



FERC Commissioner Mark Christie | *FERC*

Since Ohio law states that "no entity shall own or control transmission facilities … unless that entity is a member of, and transfers control of those facilities to, one or more qualifying transmission entities," the OCC argued that the adders do not comport with subsequent court decisions and commission orders establishing that the purpose of the adder is to incentivize a voluntary action.

"In other words, the transmission owners are making consumers pay them higher profits to comply with Ohio law," the OCC protest states.

The two AEP utilities unsuccessfully argued that since its affiliates set a single transmission rate uniformly across several states, the removal of the adder in one state would effectively "privilege one state's mandate over another states' decision to leave RTO membership up to the utility." The company also claimed that an Ohio-only remedy would be impractical as it would require AEP to disaggregate its transmission operations for each state, eliminating efficiencies that benefit customers.

The precedent for the voluntariness requirement was established with the commission's Order 679, which established the adders to comport with Federal Power Act Section 219, which requires that incentives be given to utilities that join transmission organizations.

In 2018, the 9th Circuit Court of Appeals ruled that PG&E is entitled to an adder as its participation in CAISO is voluntary, finding that "the voluntariness of a utility's membership in a transmission organization is logically relevant to whether it is eligible for an adder." (See *PG&E Deserves $30M ISO Adder, FERC Says.*)

The protest also points to FERC's 2021 order that Dayton Power and Light Co. is ineligible for an adder under Ohio law (*ER20-1068*).

The OCC estimated the cost of the adder at more than $26 million across the four utilities, which it told FERC is likely conservative as it only takes into account over-earnings on projects in PJM's Regional Transmission Expansion Plan. The commission granted the protest's request that refunds be issued to customers of Ohio Power and AEP Ohio for the amount

FERC Commissioner James Danly | © *RTO Insider LLC*

they were charged going back to the Feb. 24 filing date.

Danly Dissents

Commissioner James Danly dissented with the commission's finding that the AEP utilities no longer receive the RTO adder.

He argued that the FPA does not limit the incentives to those who join and remain members of an RTO voluntarily and that the 9th Circuit Court of Appeals only interpreted FERC's Order 679, not the underlying federal law. The ruling does not address whether the commission exceeded the FPA by limiting the incentive to voluntary participants, Danly added.

"The Federal Power Act does not limit incentives to only those utilities that 'voluntarily' join a transmission organization. The commission improperly added this non-statutory requirement in Order No. 679. We had no authority to do so then or now," Danly wrote.

Christie Concurs

Commissioner Mark Christie issued a concurrence in which he noted that a majority of commissioners voted in April 2021 to limit the RTO adder to three years after a utility joins a transmission organization.

"Over a year and a half later, we have yet to take a final vote to implement that limit. As long as we do not, consumers will continue to pay these adders at a time when consumers are already facing rapidly rising monthly power bills," he said. ■

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Wednesday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider.*

RTO Insider will be covering the discussions and votes. See Jan. 3's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse proposed *revisions to Manual 10*: Pre-Scheduling Operations resulting from a periodic review.

C. Endorse proposed *revisions to Manual 14D*: Generator Operational Requirements resulting from a periodic review.

D. Endorse proposed *revisions to Manual 27*: Open Access Transmission Tariff Accounting resulting from a periodic review.

E. Endorse proposed clarifying tariff and Operating Agreement (OA) *revisions* as endorsed by the Governing Documents Enhancements and Clarifications Subcommittee (GDECS).

Endorsements (9:10-10:10)

1. Energy and Reserve Market Circuit Breaker (9:10-9:40)

Adrien Ford of Old Dominion Electric Cooperative will present the *main motion* for a proposed "circuit breaker": a mechanism for limiting extremely high prices. David Scarpignato of Calpine will present an alternative motion for a proposal.

Stakeholders have expressed mixed opinions on the issue, with a poll conducted in the Energy Price Formation Senior Task Force yielding less than 50% support for each of the seven packages then under consideration. Discussion was tabled during the November MRC so that ODEC and Calpine could attempt to form a compromise package. (See "Support for Circuit Breaker Remains Mixed," *PJM MRC Briefs: Oct. 24, 2022*.)

The committee will be asked to endorse a proposed solution.

Issue Tracking: *Operating Reserve Demand Curve (ORDC) & Transmission Constraint Penalty Factors*

2. Rules Related to Market Suspension (9:40-9:55)

PJM's Stefan Starkov will review a *proposal* addressing the treatment of long-term market suspensions, meant to provide a solution for settling real-time market prices when they cannot be determined. (See "Market Suspension," *PJM Market Implementation Committee Briefs: June 8, 2022*.)

The committee will be asked to endorse the proposed solution.

Issue Tracking: *Rules Related to Market Suspension*

3. Market Participant Default Flexibility (9:55-10:10)

PJM's Colleen Hicks will present a *proposal* to allow the RTO flexibility to allow market participants to continue operating in markets after a default under certain circumstances. (See "1st Read on Proposal to Allow Flexibility for Market Participation During Defaults," *PJM MRC Briefs: Nov. 16, 2022*.)

The committee will be asked to endorse a proposed solution and corresponding tariff and OA revisions.

Issue Tracking: *Market Participant Default Flexibility*

Members Committee

Consent Agenda (1:35-1:40)

B. Endorse proposed tariff and OA *revisions* supporting the transmission constraint penalty factor solutions package. (See "TCPF Adjustments Permitted for Issues with Ongoing Solution," *PJM MRC Briefs: Nov. 16, 2022*.)

Issue Tracking: *Operating Reserve Demand Curve (ORDC) & Transmission Constraint Penalty Factors*

C. Endorse proposed *revisions* to Manual 15: Cost Development Guidelines and OA Schedule 2 addressing the development of variable operations and maintenance costs. (See "MRC Approves VOM Package," *PJM MRC Briefs: Nov. 16, 2022*.)

Issue Tracking: *Variable Operating and Maintenance Cost*

D. Endorse proposed *revisions* to the tariff, Reliability Assurance Agreement (RAA) and OA to prohibit critical natural gas infrastructure load from participating in demand response programs, pursuant to the recommendations included in the FERC/NERC report on the February 2021 winter storm in the south central US. (See "Reworked Language on Critical Gas Infrastructure Participation in Demand Response Presented," *PJM MRC Briefs: Oct. 24, 2022*.)

Issue Tracking: *Critical Gas Infrastructure – Demand Response Participation*

E. Endorse proposed corresponding tariff and OA *revisions* supporting the financial transmission rights Bilateral Review and Reporting solution. The changes would require that FTR bilateral agreements be reported to PJM within 48 hours of their execution, accompanied by certain data, including FTR start/end, quantity, source and price. (See "Other Committee Actions," *PJM MRC Briefs: Nov. 16, 2022*.)

Issue Tracking: *FTR Bilateral Transactions Review and Reporting Requirements*

Endorsements (1:40-1:55)

Elections (1:40-1:55)

Michele Greening will *review the proposed* next year's sector representatives for the Finance Committee, sector whips and the vice chair of the committee. The MC will be asked to elect the proposed representatives. ■

— Devin Leith-Yessian

Mid-Atalantic news from our other channels

Ohio House Declares Natural Gas 'Green' Energy

NetZero Insider

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

SPP News

FERC Denies Tenaska's Complaints over Wind Curtailments

By Tom Kleckner

FERC on Thursday denied a Tenaska complaint alleging that several grid operators adopted operating guides that resulted in unduly discriminatory curtailment of a wind farm it owns and operates.

The commission said in its order that Tenaska failed to show unjust, unreasonable and unduly discriminatory or preferential behavior under the Federal Power Act. Because it denied the complaint, FERC also rejected Tenaska's requested relief for $9 million in lost revenue from the alleged curtailment (*EL-22-59*).

Tenaska filed its complaint in May, charging that MISO, SPP, Associated Electric Cooperative Inc. (AECI) and Tennessee Valley Authority had adopted operating guides that curtailed the Clear Creek Wind Project in a manner inconsistent with their tariffs.

The 242-MW facility sits within AECI's Missouri footprint. The cooperative is the wind farm's sole purchaser of power.

AECI is a generation and transmission cooperative and is classified as an "unregulated transmitting utility" without a tariff on file at FERC. TVA serves as the NERC-registered reliability coordinator for AECI's balancing authority and MISO and SPP neighbor the cooperative's transmission system.

FERC found MISO had not treated Tenaska in an unduly discriminatory manner, noting the company did not present any evidence that MISO has curtailed the wind farm. It also pointed out that the project is not located in MISO's footprint; that Tenaska does not take transmission service from MISO for the project; and that MISO determined that no affected system network upgrades were required for the facility to operate.

The commission ruled SPP, AECI and TVA had not treated Tenaska unreasonably, although their collective actions did result in the Clear Creek project's curtailment. However, according to the SPP-AECI joint operating agreement and SPP's tariff, the wind farm is subject to limited operation until SPP can complete network upgrades on its system.

"Therefore, such curtailment is permissible to manage congestion and ensure the reliable operation of the transmission system," the commissioners wrote.

FERC noted Tenaska's facility is subject to limited operation because it entered commercial operation before SPP was able to complete the necessary network upgrades on its system. Because of that, the commission found Tenaska is "differently situated from other interconnection customers who are not subject to limited operation."

The commission also disagreed with Tenaska's argument that SPP should be required to file its operating guides with FERC. It said SPP's operating guides are the mechanism by which the Tenaska facility's limited operation was set and do not significantly affect rates, terms or conditions of service. FERC upheld SPP's and AECI's request to not publicly release the guides.

Commission Accepts Late Agreements

The commission accepted four of five late agreements filed by Cheyenne Light, Fuel and Power, a subsidiary of Black Hills, effective Dec. 14, 2021 (*ER22-109*).

The late agreements were discovered after a comprehensive review of the utility's effective transmission and wholesale energy contracts to ensure any jurisdictional agreements were properly filed. They included a consolidated facilities agreement, an interconnection agreement, an Air Force agreement, an operating agreement and a large generator interconnection agreement (LGIA).

FERC only rejected an LGIA with Silver Sage Windpower, which dated to 2009. The LGIA contained seven non-conforming provisions, but the utility said it did not change the fact that a transmission provider under the commission's large generator interconnection process is only paid for its actual costs in facilitating the interconnection. That meant the Silver Sage agreement only provided for collection of pass-through costs associated with the generation's interconnection, Cheyenne Light said.

The commission said Cheyenne Light had not demonstrated that the deviations from the *pro forma* LGIA are necessary to address specific reliability concerns, novel legal issues or other unique factors associated with the agreements. ■

The Clear Creek Wind Project | *Mortensen Wind Energy Group*

Company Briefs

Battery Recycler Redwood Materials to Build Plant in SC

Battery recycler Redwood Materials last week said it will spend $3.5 billion to build a new plant in South Carolina.

The company said it plans to pull out key components from batteries such as nickel, cobalt, lithium and copper and reuse them to make electrodes for electric vehicles. Redwood will work with companies such as Panasonic, Volkswagen, Volvo, Proterra and Envision to build its recycled batteries.

The plant is scheduled to open in 2023.

More: *The Associated Press*

Ford F-150 Lightning Named MotorTrend Truck of the Year

The Ford F-150 Lightning was named MotorTrend's 2023 Truck of the Year last week, making it the second consecutive electric pickup to win the award.

The award is open only to models that are all-new or substantially redesigned for the given model year, which means Ford and Rivian trucks were not competing against one another. Instead, the finalists were the Chevrolet Silverado, Ram 2500 Rebel, GMC Sierra and the Toyota Tundra.

Rivian's R1T won the award last year.

More: *CNN*

McDonald's Strikes Solar Deal to Power US Supply Chain

McDonald's and five logistics partners last week signed agreements to buy 190 MW of power from the Blue Jay Solar farm that will power all warehouses, distribution centers and other elements of the logistical supply chain that serves its U.S. restaurants.

The deal is a step in McDonald's push to cut greenhouse emissions from restaurants and offices by 36% by 2030 and to become net zero globally by 2050.

Enel SPA is currently constructing the solar farm about 100 miles northwest of Houston.

More: *Bloomberg*

Federal Briefs

Kerry to Meet with Biden to Discuss Future as Climate Envoy

John Kerry, President Biden's climate envoy, last week said he intended to talk with Biden soon "about the road ahead."

Kerry, 78, said he had "no plans" to step down but would not say if he hoped to continue to represent the country in future global climate talks.

As Republicans prepare to take control of the House, several have expressed an interest in investigating Kerry's office. An October report in Axios indicated that Kerry was considering taking a position in the private sector.

More: *The New York Times*

FERC OKs Spire Natural Gas Pipeline

FERC last week voted 5-0 to approve the continued operation of the Spire STL natural gas pipeline.

Spire originally pitched the 65-mile line in 2016, got it approved by FERC in 2018, and had it running by November 2019. However, the Environmental Defense Fund sued in January 2020, arguing Spire had not demonstrated a need for the line amid flat gas demand in the region and a lack of interest from other gas providers. In 2021, a federal court unanimously revoked FERC's approval and instructed the commission, which originally approved the project by a 3-2 vote, to reassess the pipeline and address the legal flaws that marred its decision.

FERC then issued temporary permits for the pipeline to continue to operate before issuing a formal order approving the pipeline last week.

More: *St. Louis Post-Dispatch*

Biden Admin Moves to Phase Out Compact Fluorescent Bulbs

The Department of Energy proposed a new rule this week that, if enacted, would effectively phase out compact fluorescent light bulbs and move the U.S. light bulb markets decisively to more energy-efficient LEDs.

The DOE aims to finalize the rule by the end of Biden's term. The rule would more than double the current minimum light bulb efficiency level, from its current standard of 45 lumens per watt to more than 120 lumens per watt for the most common bulbs.

The DOE estimates the proposed changes will cut 131 million metric tons of carbon dioxide and 903 thousand tons of methane over the next 30 years.

More: *CNN*

State Briefs

CALIFORNIA

PG&E Cuts Workers Ahead of Winter Wildfire Maintenance

Pacific Gas & Electric reportedly let go of thousands of contractors and employees last month, including vegetation management inspectors, tree trimmers, electrical linesmen and pole testers — all workers critical to wildfire mitigation.

Union leaders told members that the layoffs were due to overspending and that PG&E overruns its budget towards the end of the year, so the company decided to push fourth-quarter work into the new year.

According to the state's Office of Energy Infrastructure Safety, PG&E is far behind on work orders for line maintenance.

More: *Grist*

ILLINOIS

ComEd to Spend $40M to Rid Homes of Natural Gas

ComEd, along with Elevate and other organizations, is moving on from a pilot program to the goal of spending $40 million over the next three years to remove natural gas and make buildings more energy efficient.

ComEd said it will fund 100% of single-family homes and up 70% of multifamily buildings that qualify. They expect several hundred conversions next year and plan to increase the numbers through 2025.

More: *Chicago Sun-Times*

LOUISIANA

New Orleans Pushes Back Climate Goals by 5 Years

New Orleans Mayor **LaToya Cantrell** last week announced a new climate action plan for the city that will push back a deadline to cut greenhouse gas emissions in half, calling for meeting that goal in 2035 rather than 2030.

The plan also calls for the city to run on clean energy by 2050.

The original goal of halving emissions by 2030 was set by Mayor Mitch Landrieu in 2017. But the city's updated plan mirrors national benchmarks set by President Biden, who announced a goal of reducing emissions by 50% by 2035 and reaching net-zero emissions by 2050.

More: *Nola.com*

MARYLAND

State Raises $1B for Climate Progress, Energy Efficiency Through RGGI

The state announced it has reached the $1 billion mark through the latest Regional Greenhouse Gas Initiative auction last week.

The auction, RGGI's 58th, netted Maryland $36.6 million in proceeds to bring its 14-year total to a bit more than $1 billion.

The proceeds will help speed the deployment of renewable energy technologies and consumer programs to improve energy efficiency.

More than half of the funds will be invested in energy assistance for low-income households and energy efficiency in low-to-moderate income homes and communities. Other investments include grants for residential and commercial solar arrays and electric vehicles.

More: *Maryland.gov*

NORTH DAKOTA

Basin Electric Seeks Approval for Power Plant Expansion

Basin Electric Power Cooperative recently filed an application with the Public Service Commission to expand its natural gas Pioneer Generation Station, in part, to accommodate a growing data center industry in the region.

The cooperative wants to expand the plant's capacity from 242 MW to 583 MW. The upgrade, along with a transmission line that would connect to the grid, would total $790 million.

If approved, Basin hopes to start construction in April and finish the first phase of the project by August 2025.

More: *The Bismarck Tribune*

OHIO

PSB Denies Solar Project Application

The Power Siting Board last week denied Vesper Energy's application for a utility-scale solar project in Greene County.

The board said it found that, based on the unanimous opposition to the project by local governments whose constituents are impacted by the project, the project would fail to serve the "public interest, convenience and necessity" as required by state law.

Vesper has 30 days to file an application for a rehearing on the board's decision.

More: *WYSO*

Siting Board Approves Second Solar Project in Franklin County

The Power Siting Board last week approved the 155-MW Springwater Solar project in Franklin County.

The project will also include a 75-MW battery energy storage system.

Construction of the project, which is developed by Apex Clean Energy Holdings, is expected to start in the spring and take 16 months to complete.

More: *The Columbus Dispatch*

OREGON

Milwaukie Bans Natural Gas in New Construction

The Milwaukie City Council last week banned natural gas hookups in new construction and ordered natural gas to be removed from existing city-owned buildings through retrofit. Both resolutions will go into effect in March 2024.

The passage of the resolutions means that new homes and apartments will be outfitted with induction ranges and heat pumps instead of traditional gas stoves and furnaces.

Councilmembers said the decision was key to the city's climate action plan, which calls for net-zero emissions from buildings by 2035.

More: *KGW*

PENNSYLVANIA

Equitrans Methane Leak Tops List of Worst US Climate Disasters of 2022

A methane leak from a 1 5/8-inch vent on a natural gas storage well operated by Equitrans Midstream was discovered on Nov. 6 and lasted for 13 days, allowing more than 1 billion cubic feet to escape. It has become one of the biggest U.S. climate disasters in recent years.

The two-week-long release effectively erased emissions gains from about half of the 656,000 electric vehicles sold in the country last year. The company initially said it halted the flow of gas on Nov. 17 but revised that after venting resumed. The well was finally plugged on Nov. 19.

The Department of Environmental Protection said in a report that it was investigating the incident and has subpoenaed documents from the company.

More: *Bloomberg*

TEXAS

Acciona Energía Acquires State's Largest Storage Project

Madrid-based renewable energy operator Acciona

Energía last week announced it has acquired the 190-MW Cunningham storage project. Financials of the deal, which includes six additional projects, were not disclosed.

The project was previously owned by Qcells Co., which purchased it from Belltown Power Texas about a year ago.

Construction of the facility is expected to be finished by March.

More: *The Dallas Morning News*

Companies Sue Comptroller Over Denied Tax Savings

Stetson Renewables Holdings and Ogallala Renewable Project, two renewable energy companies, last week sued the Comptroller's office, alleging the office denied their requests for more than $20 million in tax savings because it can't handle the number of entities seeking approval before the Dec. 31 deadline.

The companies submitted their applications in May 2022. In a request to the Supreme Court, attorneys said Comptroller Glenn Hegar informed them that the Chapter 313 applications were received before the deadline and they were eligible for incentives. However, after eligibility is determined, the office is required to conduct an economic impact evaluation on the application within 90 days, the companies said. The attorneys asserted that Hegar failed to complete the review in time, which resulted in the applications' denial.

In a statement, Hegar said his office has seen an "extraordinary number of applications from companies seeking to secure an incentive under the current program" and noted his staff had to manage a workload that has significantly increased despite no additional staffing support.

More: *The Texas Tribune*

Tesla Powerwall Customers to Test 'Virtual Power Plant'

Tesla last week received approval to create a "statewide market design pilot" policy for a virtual power plant (VPP), according to Tesla's U.S. markets policy lead Arushi Sharma Frank.

Texans who own Powerwalls, which serve as a backup power supply, would allow ERCOT to pull energy from the batteries when the grid has need. Tesla launched a VPP program last year in California, where customers would be compensated $2 per kWh when power is shared during times of peak demand. It is not clear how much Texas owners would receive, or other details of the policy, but Tesla lobbied for 200 voluntary participants in May to test the program.

More: *My San Antonio*

VIRGINIA

Henry County Approves Solar Project Permit

The Henry County Board of Zoning Appeals last week approved a special use permit for a proposed large-scale solar project.

Axton Solar's original plan called for about 1,203 acres, but a revision put it at around 1,092 acres with about 434.5 acres used for solar.

More: *WSET*

SCC Approves OSW Settlement

The State Corporation Commission last week accepted a settlement over ratepayer protections tied to Dominion Energy's Coastal Virginia Offshore Wind Project.

The settlement was proposed by Dominion, the attorney general's office, Walmart, nonprofit Appalachian Voices and the Sierra Club in October following claims from Dominion CEO Bob Blue that the $9 billion project was "untenable" if regulators required a performance guarantee. The guarantee previously tied to the project's approval mandated that if the wind farm didn't produce 42% of the energy it could generate, then the company, not ratepayers, would have to pay for replacement energy costs.

Instead of the performance guarantee, the settlement requires regulators to review any shortcomings in energy production and then decide an appropriate way to handle those shortfalls.

More: *Virginia Mercury*

WEST VIRGINIA

Doddridge County to be Location of Proposed Natural Gas Plant

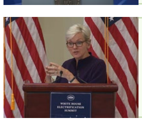
Competitive Power Ventures last week confirmed that Doddridge County will be the location of a new 1,800-MW, combined-cycle natural gas plant that will also use carbon capture and sequestration to reduce its greenhouse emissions.

The $3 billion Shay Energy Center is expected to be completed in the next 10 years. Once completed, the plant will be a wholesale energy provider on the PJM market.

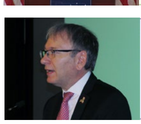
More: *The Parkersburg News and Sentinel*

National/Federal news from our other channels

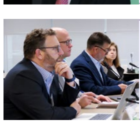
Granholm: Sustained Fusion May be Possible Within a Decade



White House Summit Kicks off Push for Home Electrification



NERC Standards Committee Briefs: Dec. 13, 2022



SERC Board of Directors Briefs: Dec. 14, 2022

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