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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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FERC Tech Conference: Tx Planning & Cost Control

FERC Tech Conference Highlights Regulatory Gaps on Tx Oversight

Christie Suggests Barring Some TOs from Formula Rates

By Michael A. Brooks, John Cropley, Amanda Durish Cook and Rich Heidorn Jr.

FERC Commissioner Mark Christie | *FERC*

FERC Commissioner Mark Christie said Thursday that the commission should consider limiting formula rate authority to transmission owners whose projects are subject to "robust" state regulatory reviews to help close the "regulatory gaps" between state, federal and RTO oversight.

Meanwhile, state officials and consumer advocates told FERC's technical conference on transmission planning and cost controls (AD22-8) that the commission should also provide more scrutiny of formula rates, under which expenses are presumed to be just and reasonable.

Christie was incredulous when Indiana regulator Sarah Freeman, president of the Organization of MISO States, said that her state has no process for reviewing transmission projects.

"There is a gap in what scrutiny is taking place at the state level, and yet that is where all these projects should be scrutinized," Christie, a former Virginia regulator, said at the close of the hearing. He said the testimony showed state oversight on the cost and prudence of projects "varies greatly."

FERC has "authority over [just and reasonable] rates at the wholesale level and transmission. We don't have authority to tell a state how to structure your CPCN [certificate of public convenience and necessity] process, but we do have authority to say who gets formula rate treatment when you come here," Christie said. He invited stakeholders to submit comments on whether FERC should limit such rate treatment to TOs from states with a "robust state permitting process."

"At a minimum, a robust state permitting process would be looking at, not just [the] prudence of cost, but also looking at need," Christie said. "If you look at the three sections we've talked about today — the RTO planning part; the state CPCN part; and then the formula rate part [at FERC] when it comes to how to pay the bill — each one of those really connect."

FERC Chair Richard Glick | *FERC*

FERC Chair Richard Glick said he was taken aback by Iowa Consumer Advocate Jennifer Easler's written testimony, which described the state's lack of authority over the cost of local transmission projects.

"When they come in for the franchise application, we do conduct discovery on it, and we ask, 'What alternatives did you consider?'" Easler said. "And we will get responses along the lines of, 'We object. The costs of these projects are not regulated by the Iowa Utilities Board.'"

Glick said the conference exposed both a regulatory gap and "an informational gap," as evidenced by regulators and consumer advocates who said they lack the access to information on local transmission plans or the expertise to evaluate them. "Those are two items I think we need to address going forward," he said in his remarks concluding the conference. "We have, in my opinion, more work to do on transmission and hopefully more [Notices of Proposed Rulemakings] to come at some point."

States Seek Help

Cameron Dyer, Public Utilities Commission of Nevada | *FERC*

FERC heard from officials of eight states and D.C. during the daylong conference.

Cameron Dyer, senior assistant general counsel for the Public Utilities Commission of Nevada, said there is only one vertically integrated investor-owned utility in his state — NV Energy — that "handles just about all the transmission in the state, which means that any time new transmission is being proposed — in the intrastate context, at least — there is a lot of robust interview, review and analysis of that new transmission."

Most state officials were less sanguine.

The topic of the first of the five panels at the conference was the development and use of criteria for local transmission planning, where state regulators and municipal utilities told the commissioners they often don't have any idea what those criteria are.

Under FERC Order 890, "we get the baseline reliability criteria from the transmission providers and [their] specific engineering criteria for their projects, and that's all," said Dan O'Hagan, manager of regulatory compliance for Florida Municipal Power Agency. "We don't get other criteria that go into that decision-making process, like end-of-life for facilities, or cost considerations, or public policy considerations ... that might come into play behind the scenes where they select one project over another."

Simon Hurd, California Public Utilities Commission | *FERC*

Simon Hurd, program and project supervisor with the California Public Utilities Commission, said the PUC appreciates its working relationship with Southern California Edison and Pacific Gas and Electric, but the discussions are mostly past-tense because 63% of utility projects are self-approved. These projects are not put into the transmission planning process and they do not get CAISO review, he said.

"We need to be more upstream. ... We want review; we want input in the process at the assumptions, the needs, the solution stage. We're doing our best to be having that conversation with the utilities, but it's after the solutions have already been identified," Hurd said.

Too Late

James McLawhorn, North Carolina Utilities Commission | *FERC*

James McLawhorn, director of the North Carolina Utilities Commission's Energy Division, said the NCUC enters the process too late.

"We have attempted to question some of the projects that have been proposed as to whether there are other options. ... By the time it comes to us, we're being told, 'Well, no, this is the only solution that was available and now we're out of time and we need to move forward with it,'"

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he said. "Maybe it was the only solution that was available, but we simply don't have the information to evaluate that."

McLawhorn, who advocates for consumers as part of his job, was among speakers who favored an independent transmission monitor to increase oversight of the transmission planning process.

"The commission looks for us to do the evaluation, to come to them and make recommendations, but we do not have particular transmission expertise on staff, and we desperately need something like an independent transmission monitor to assist us," McLawhorn said. (See related story, *States Urge More Transparency on Tx Planning, Independent Monitors*.)

The North Carolina commission recently engaged a transmission consultant to provide that help, McLawhorn said, but the process was a struggle. There was one response to the request for proposals, he said, and it came in on the last day of the submission period.

Phil Bartlett, chair of the Maine Public Service Commission, said that by the time his agency gets to review a transmission project, it "is pretty far along."

"So even a very robust process, in my view, is not a substitute for really engaging early on the planning process. It's also not a substitute for following through afterwards."

In contrast with FERC's lack of scrutiny for prudency, Bartlett said, "we are always looking at the prudency of investments that have been made. And that includes the management of those projects in development. We routinely disallow costs if we think there are unreasonable overruns or other issues. So, both in terms of not being present at the planning stage, and not being present after the CPCN process on the cost-management side, I think it's a real shortcoming of even the most robust CPCN process."

Formula Rates

Bartlett and others said the use of formula rates has shifted the burden of proof. In state rate cases, TOs must demonstrate just and reasonable rates; under formula rates, states and consumer advocates must rebut the proposed rate.

Rhode Island Public Utilities Commission Chair Ron Gerwatowski | *FERC*

Ron Gerwatowski, chair of the Rhode Island Public Utilities Commission, said his commission recently discovered that Narragansett Electric (now Rhode Island Energy) was collecting $10 million a year in excess profits on its transmission line connecting the Block Island offshore wind farm to the mainland.

"It is telling to consider that the windfall profit being generated from the formulaic cost-recovery mechanism used in this case was only discovered because someone in the accounting department of the utility misallocated revenue and expenses to the wrong business unit in a report on distribution earnings," he said in his written testimony. "But for that human error, neither the Rhode Island PUC nor FERC's processes would have picked up the continuing windfall profits flowing from ratepayers to shareholders."

Gerwatowski said that more than $2.5 billion in "asset condition" projects have been placed in service in New England and $3.1 billion more are listed in ISO-NE's Regional System Plan (RSP) as proposed, planned or under construction. By comparison, as of the June 2022 RSP update, reliability projects in the pipeline resulting from the ISO-NE planning process total less than $1.3 billion.

Attorney Robert Weishaar, who represents industrial consumers, said FERC's Office of Administrative Litigation (OAL) could play a larger role in the transmission formula rate review process.

Robert Weishaar, McNees Wallace & Nurick | *FERC*

He said OAL staff are "extremely helpful" in the initial establishment of formula rates but become uninvolved when it comes time for annual updates. Weishaar suggested that FERC expand OAL's authority and resources so staff can engage in the annual update process and "review the actual flow-through of the costs."

Larry Gasteiger, executive director of WIRES, saw it differently. He said formula rate protocols involve "extensive" stakeholder sessions with utilities and opportunities to challenge the rate inputs.

In addition, he said, FERC has "a fairly robust" program for auditing utilities with formula rates. "The audits, I know from personal experience, are extensive," said Gasteiger, who served at FERC for almost two decades, including almost six years as a top official in the Office of Enforcement. "And they are effective, because they do a very thorough examination of how adherence to the rate protocols and the formulas is all working.

"If you believe the rhetoric around it, FERC has all but abandoned any regulation of transmission rates in this context," he continued. "I think it's important to debunk that notion. Maybe it plays well in the Twitter-space, but it doesn't reflect the reality of what is going on here."

But FERC Commissioner Allison Clements noted that the commission only conducts about a dozen audits a year. Although the Office of Energy Market Regulation has "improved stakeholders' ability to engage on formula rates," the "structural problem" with formula rates may require appointing independent transmission monitors, she said.

"The cost is peanuts on the dollar of deferring just one transmission investment," she said. "But if that's not the way you think we get at these problems, we certainly are open to other ideas. … I think I hear a real need to take action."

In addition to increasing its scrutiny of formula rates, Bartlett said FERC should revisit the return on equity allowed for formula rate investments. "Given the lack of oversight and difficulty in challenging prudence, there is little risk in undertaking these investments and the ROE should reflect that," he said.

Iowa Consumer Advocate Easler was also critical.

"Transmission providers that use forward-looking formula rates with incentive ROE adders and obtain automatic cost recovery of transmission costs from retail customers via state-authorized transmission cost trackers simply do not have a strong incentive to engage in least-cost transmission planning for lower-voltage local transmission facilities," she said in her written testimony. "The absence of customer-initiated challenges to local transmission upgrades in formula rate reviews is not an indication that all is well. Rather, in the face of relentless transmission rate increase, it is an indication that this regulatory process is inadequate to protect customers from unjust and unreasonable charges resulting from inefficient siloed transmission planning processes." ■

FERC Tech Conference: Tx Planning & Cost Control

States Urge More Transparency on Tx Planning, Independent Monitors

By Michael Brooks, John Cropley, Amanda Durish Cook and Rich Heidorn Jr.

State regulators and consumer advocates urged FERC on Thursday to order the creation of independent transmission monitors and other measures to increase oversight over transmission owners' planning and spending.

Multiple speakers at FERC's daylong technical conference on transmission planning and cost controls said FERC action was needed to address an "information asymmetry" in transmission planning and the TOs' increasing spending on local transmission projects that face little oversight (*AD22-8*).

In PJM, for example, transmission owners' spending on local "supplemental" projects since 2014 has dwarfed that on baseline projects meeting regional needs, which are vetted through the RTO's Regional Transmission Expansion Plan.

Independent Transmission Monitor

The commission heard from more than three dozen witnesses, many of whom said they supported the creation of independent transmission monitors to provide expertise enabling RTOs and state regulators to ensure their stakeholders' transmission dollars are being spent most cost effectively.

Michael Haugh, director of analytical services at the Office of the Ohio Consumers' Counsel, said consumer advocates don't have access to enough information to ensure project costs are prudently incurred.

"We don't know what we don't know, and that's a big issue. … We've found that more independence in these types of situations is better," he said.

Haugh said an independent monitor would be particularly helpful in PJM for TO-proposed supplemental projects, where PJM's only review is to make sure they do not harm reliability.

"We feel … an independent monitor would be able to look at these independently and see if there are competitive solutions that are better," he said.

Robert Weishaar, McNees Wallace & Nurick | *FERC*

"Our view is that all transmission facilities over which the commission has jurisdiction should be planned by an independent transmission planner," said Robert Weishaar, energy lawyer for McNees Wallace & Nurick, who represents industrial customers in MISO and PJM. He said an independent transmission monitor could have a standing set of engineers that could analyze and review projects from an objective standpoint.

Weishaar said for years there's been a "somewhat artificial regulatory distinction" between local and regional transmission projects in terms of oversight, cost recovery and eligibility for competition.

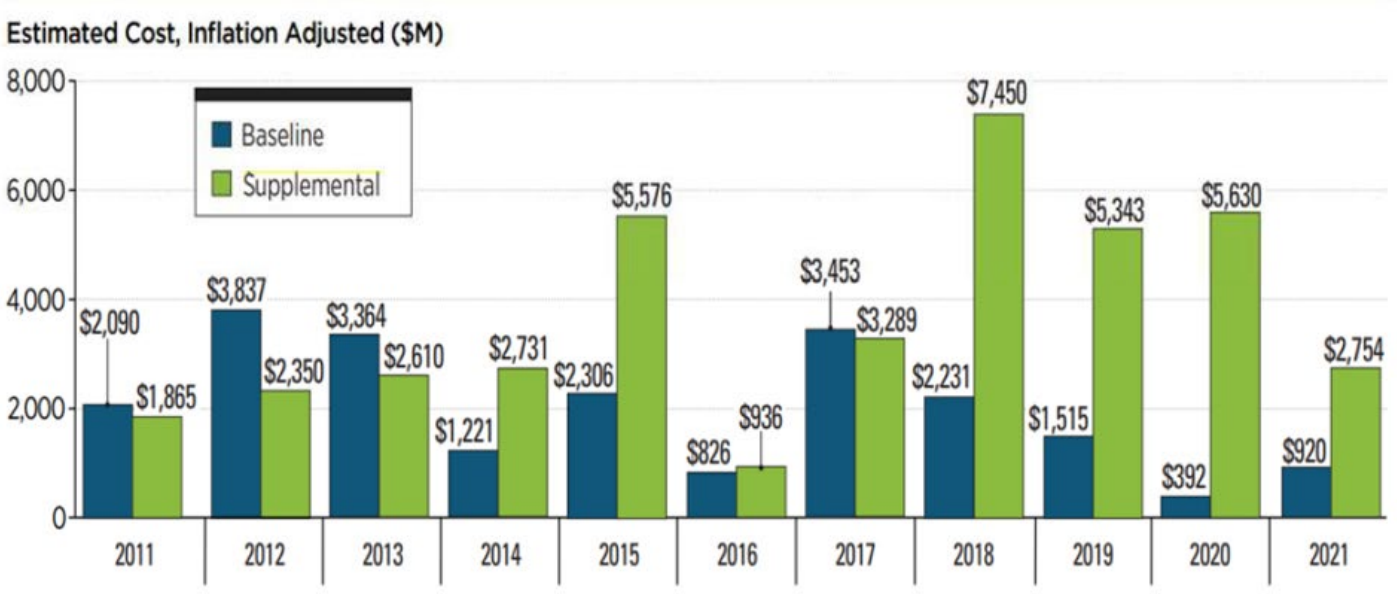
Rhode Island Public Utilities Commission Chair Ron Gerwatowski | *FERC*

Rhode Island Public Utilities Commission Chair Ron Gerwatowski said someone "with the authority of the commission" involved at the start of a transmission planning process would create "a cost oversight which I believe does not exist in New England today."

"It's not so much the information because there are protocols that are put in place that are actually very helpful [to] anyone that has the expertise to look at it. But the question is, 'Who's looking at it?'" Gerwatowski said.

Gerwatowski said a monitor would introduce some degree of risk to today's essentially no-risk rate system, which he said he believes is not FERC's intent. "The way you recover transmission rates is: Spend the money; get the money. Spend the money; get the money," he said.

Kentucky Public Service Commission Chair



PJM transmission owners' spending on local supplemental projects that face little oversight has dwarfed that on baseline projects meeting regional needs since 2014. | *PJM*

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Kent Chandler said an ITM would provide benefits similar to that of independent market monitors in RTO markets.

Kentucky Public Service Commission Chair Kent Chandler | *FERC*

"I don't think there's anything, for instance, that the IMM in MISO or the IMM in PJM do to usurp state authority in relation to choosing our generation. ... They provide us with an incredible amount of information in that regard. I can understand people saying it might be an extra layer of bureaucracy, but for many of these projects, it may be the only set of eyes [that would look at] the need and the planning. ... I look at it as being an opportunity to provide any of us [regulators] evidence ... an independent set of eyes who actually knows what they're talking about."

Henry Tilghman, speaking for the Northwest & Intermountain Power Producers' Coalition, said regional independent transmission monitors would be more efficient than leaving the responsibility to states.

"The reality in the West is if you're doing a regional transmission project, you've got four, maybe five, states plus probably a federal government agency, Bonneville Power Administration. And is it really more efficient to require each of those individual states to staff up to do that sort of independent analysis of the transmission proposals? Or is it more efficient to have a single entity who has the expertise who can provide each of the states consistent information about a proposed project? And I think it is."

"We have an opportunity, I think, to manage the cost a lot better and the project activity as it's being proposed," said Randy Howard, general manager of the Northern California Power Agency. "Because right now, there's just not a way for us to do that. ... We just don't get access early enough in the process to influence the prioritization of what's important for reliability and resiliency. And obviously, through our wildfires and other activities, we've seen where some of our projects that we tried to impress upon those utilities that should be done earlier, weren't done. And then consequences occurred."

TOs Push Back

Witnesses representing transmission owners strongly opposed the ITM concept.

Carolyn Cowan Barbash, vice president of transmission development and policy for NV Energy, said an independent planner isn't necessary in the West, where states are larger and regulatory processes are sufficiently transparent.

WIRES Executive Director Larry Gasteiger argued that sub-delegating the authority of FERC to independent transmission monitors would invalidate their independence. He said he was troubled by the expectation that FERC lend out its authority to a third party when the commission itself should have oversight authority over costs.

Charles Marshall, vice president of transmission planning for ITC Holdings, said his company offers a high degree of data visibility on its proposed transmission projects, no matter how small the price tag.

Charles Marshall, ITC Holdings | *FERC*

Also, he said, ITC cancels plans that internal reviews show are no longer needed.

"That's not a tariff requirement; that's something that we've committed to our stakeholders to do," Marshall said. "We're continuously internally reviewing the merits of projects that we've yet to commence construction on."

Jeff Burleson, a senior vice president at Southern Co., recalled an instance several years ago in which the utility was able to cancel a major transmission line it was planning through virtue of its vertically integrated structure.

Jeff Burleson, Southern Co. | *FERC*

"Effectively, all of our planners sit around the same planning table — generation planners, transmission planners, fuel supply planners — and we look at the alternatives," he said. "And one of the alternatives we saw to this 90-mile, 500-KV line was siting generation close to the load.

"I don't think an independent monitor would be helpful to us," Burleson said. "I think it would just add an additional layer of bureaucracy."

Attorney Jon Schneider, a partner in Stinson LLP who spoke on behalf of the Large Public Power Council, also expressed doubts about the ITM's value in controlling costs.

"We have three institutions on the scene as we speak: We have [FERC]; we have state commissions; we have RTOs and ISOs. And if we need a fourth institution, it does strike us that something's sort of going wrong with respect to the oversight exercised by the folks that are already looking at this," he said.

"If you improve the transparency of the processes, beef up staffs at the state and [FERC] and on the RTO level, we're not sure that the ITM is cost beneficial with respect to cost oversight. We're not unsympathetic to it ... but we're a little bit circumspect."

Defining ITM's Role

MISO Director of Expansion Planning Jeanna Furnish said FERC should consider whether it intends for an independent transmission monitor to be a one-stop solution and what its role will be in disseminating information, holding meetings and engaging consumer advocates and state regulators.

Furnish pointed to MISO's ongoing long-range transmission planning effort, which considers a multitude of reliability needs.

"Is it actually appropriate to put all the eggs in one basket? ... Are we talking about 350 projects and there's capacity for this independent transmission monitor to think about alternatives for every single project? I mean, that's a huge work effort," she said.

"And that's another question about how much would all of that cost," Commissioner Willie Phillips agreed.

Commissioner Allison Clements said that while the set of responsibilities of independent transmission monitors is "not yet fully baked," a monitor proposing alternatives to every single project "isn't really the spirit" of what FERC is considering.

Robert Ethier, ISO-NE's vice president of system planning, said an ITM could provide needed resources but that the model should not be that of the market monitors.

"There's a need for more public planning ability, more public technical capability, but I'm not sure that an ITM reporting to [FERC] or ... reporting to the ISO makes sense. If we have an ITM that reports to the states, I could understand that, because to me, what the states need are more resources to deal with the future. ...

"We, in New England at least, are going to ask a lot more of the states going forward. We are going to look to them for guidance on public policy projects in a way that we never have before. And it frankly makes me nervous, the idea that they're not going to have additional resources to help fill that role."

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Pallas LeeVanSchaick, vice president of Potomac Economics, the market monitor for MISO, NYISO, ISO-NE and ERCOT, said RTOs can't be expected to provide independent oversight of transmission owners' local projects.

"We've found that [RTOs are] extremely deferential to the concerns of the local transmission owners, and it's just hard to see that they'll be able to scrutinize things or ask questions or get them to look at alternative assumptions in the way that you would need," he said.

FERC Authority Questioned

Glick asked Ari Peskoe, director of the Harvard Electricity Law Initiative and prolific social media commentator, whether he believes FERC has jurisdiction to require regions to establish independence reference monitors, joking, "[I] normally get great legal advice [from you] on *Twitter*."

Peskoe said FERC has authority through Order 890, which was "intended to provide transmission customers and other stakeholders a meaningful opportunity to engage in planning along with their transmission providers."

"There's a lot of evidence that we've heard today and in the record, and as well as in the RM21-17 [Notice of Proposed Rulemaking on transmission planning] that that just isn't the case right now. And so, I think an ITM could be a solution to that."

Commissioner James Danly, who participated by phone and spoke little during the conference, disagreed.

Witnesses appear before FERC during a daylong technical conference on transmission planning and cost containment. | *FERC*

"I'm not entirely sure that our jurisdiction is a complete, obvious case that we have the power to do these things," he said. "I don't see a whole lot about meaningful opportunities to engage in the Federal Power Act text. And even granting that we have the jurisdiction to do it, we still have requisite statutory showings where we have to show under [Section 206] that the rates are not [just and reasonable]. And applying universal solutions across every region — despite the actual rates that are the result in the planning processes — I think is probably violative of the statute's requirements."

Peskoe also said the commission could order monitors in non-RTO areas as well as organized markets. "The commission's open-access rules apply to all utilities," he said. "Assuming the commission believes it can still supplement its open-access policies, I believe they would apply to all utilities [and] transmission providers." ■

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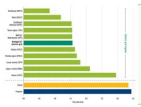

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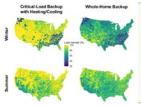

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Transmission Owners, RTOs Defend Planning, Cost Control Practices

PJM M-3 Process only the 'Appearance of Transparency,' Critics Say

By Michael A. Brooks, John Cropley, Amanda Durish Cook and Rich Heidorn Jr.

Transmission owners found themselves on the defensive throughout Thursday's FERC technical conference on transmission planning and cost management, as panelists decried the rising spending on end-of-life and other local projects that do not face any prudency reviews.

Kamran Ali, vice president of transmission planning and analysis at American Electric Power (NYSE:AEP), pushed back against the criticism, saying PJM's Attachment *M-3 process*, which governs planning of supplemental projects — those not needed for system reliability or public policy compliance — is "the gold standard" for transparency.

"I can say that because I manage the transmission planning for AEP in four different RTOs," Ali said. "I think it would be beneficial if people were to bring actual factual examples to the table: 'In the M-3 process, here are the regional projects that would have displaced local projects, or here are the local investments that were not prudent, that were not rationalized that somehow made it through.' If we have some of those real examples, I think we can enhance the M-3 process. Without examples I think it's very difficult to make any improvements."

PJM evaluates supplemental projects only to make sure they do not harm reliability. Municipal stakeholders have long complained about the lack of transparency surrounding their costs. (See *PJM TOs Sign off on Supplemental Project Deal*.)

Lisa McAlister, American Municipal Power | *FERC*

Lisa McAlister, general counsel for regulatory affairs for American Municipal Power, responded that the reason that there are no examples is "because we simply don't have enough information to identify" any. She said AEP does "a better job" than other PJM TOs in providing information, but "what we don't have is how those replacements are prioritized; we don't know [how] replacement versus maintenance decisions [are made]; how assets rank compared to other assets on the system."

Kamran Ali, American Electric Power | *FERC*

'Appearance of Transparency'

Kentucky Public Service Commission Chair Kent Chandler | *FERC*

"AEP has done a very good job in the M-3 process of responding to a limited number of suggestions," agreed Kentucky Public Service Commission Chair Kent Chandler. "I have a certain number of questions, and [there] are now stock answers that they're ready to provide people. ... The reality is that although I understand what their criteria is ... I have no idea what weight they're giving" to them.

"The M-3 process gives us far more insight into local planning than the non-RTO utilities that we have, and even the MISO utility that we have," Chandler added. "We understand through the M-3 process what their assumptions are and the criteria maybe, but there's no way that we're provided enough information to be able to replicate the decisions that are made by the utilities. So we understand that they may be looking at asset conditions, [but] we have no idea what kind of weight they're giving them; whether they're prioritizing certain conditions over others. It's the appearance of transparency, and it's enough to maybe placate some folks ... but it is not enough to have an appreciation for how they're actually doing local planning."

But that's still far more than what the PSC gets from its non-RTO utilities, he said. "We don't find out what their planning outputs are until they show up to the commission for a certificate of public convenience and necessity, or it's a fairly small transmission project and we don't see until they file a rate case and it shows up in their forecasted test period. ... We have no insight into their local planning."

McAlister said RTOs should do more rigorous analyses of local planning criteria and proposed projects. But "to really have a meaningful opportunity to have a back-and-forth, you need more than the ability to submit comments," she said. "There has to be some kind of actual requirement that the transmission owners respond."

She said PJM created a website for members to submit questions, but the RTO usually just says, "we're working with the transmission owners; we'll get back to you." She said mirroring the M-3 process in other regions, "just

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having an arbitrary set of meetings and days to comment, we don't think is something that gets us there."

Greg Poulos, Consumer Advocates of PJM States (CAPS) | *FERC*

Greg Poulos, executive director of the Consumer Advocates of PJM States (CAPS), said in-house experts can only do so much.

"We have the money to hire an expert. I just don't know what our expert would do with only 10 days to review projects, no ability to ask the questions and no expectation that they're going to respond to us," he said.

"Those are things you would hear from … an independent transmission monitor: 'Those are flaws in this process. There's a significant gap here [and] PJM, you need to do something about that.' It's different from me saying that, because I'm not getting response to that."

PJM Cites Difficulty Identifying Regional Projects

Kenneth Seiler, PJM | *FERC*

Kenneth Seiler, PJM's vice president of planning, said the RTO has not pursued more regional projects because the RTO is not seeing high load growth except in some areas such as Northern Virginia, which has experienced an explosion of data center load. (See *PJM Sees Additional $603M 'Data Center Alley' Tx Spend*.)

"We look for opportunities for regional transmission, but in many cases, it's not the most cost-effective solution," Seiler said. "We have had occasions in the past, though, where we had identified regional solutions [and] we could not get the line sited. The one example I can think of off the top of my head was about a $100 million regional transmission facility … The [state] commission wouldn't site it within that particular state. And we ended up spending over double — over $200 million for sub-transmission upgrades."

Erik Heinle, D.C. Office of the People's Counsel | *FERC*

Erik Heinle, of the D.C. Office of the People's Counsel, said PJM's expertise in engineering and power flow analysis is "world class."

"But we see far too many instances where PJM is not acting as the regional planner and bringing regional projects to the region," he said.

Existing Cost Containment Practices

FERC Commissioner Willie Phillips | *FERC*

FERC Commissioner Willie Phillips expressed interest in MISO's variance analysis, in which the RTO reevaluates projects facing lengthy schedule overruns or a 25% cost increase. MISO can either let projects continue, cancel them or assign them to different developers. Jeanna Furnish, MISO's director of expansion planning, said the variance analysis could be applied in other regions to scrutinize projects.

SPP Executive Vice President of Regulatory Policy Paul Suskie said that, more than a decade ago, SPP's first regionally funded 345-kV line turned out to be significantly more expensive than its original estimate, causing the RTO's Regional State Committee to call for a review and develop methods to contain costs. Since then, Suskie said, SPP has been tracking project costs in an evolving process. He said projects that exceed 20% of their original costs are subject to restudy, suspension and even cancellation.

FERC Chair Richard Glick asked transmission owners how they currently reduce cost exposure for customers on large, regional transmission projects.

Carolyn Cowan Barbash, vice president of transmission development and policy for NV Energy, said her company tries to write projects' technical specifications as clearly as possible and makes sure it attracts multiple bidders on solicitations.

Ameren Transmission Company (NYSE:AEE) President Shawn Schukar said his utility considers how large projects will impact future projects and vets contractors for past performance in addition to their cost estimates. He also said Ameren considers the quality of transmission components and how often they might need maintenance and replacement. He said he "took exception" to the perception that transmission owners aren't currently motivated to keep costs in check.

'Cooking the Books'

Attorney Lauren Azar, a former Wisconsin regulator, said FERC should create a process for challenging local planning criteria (LPC), saying "a few bad apples" in MISO have overly restrictive criteria for the generation interconnection process.

"Even before any new generation is added into the models, upgrades are already required, because of the LPCs. So in other words, the TOs are cooking the books so that those generators are required to pay for those upgrades, even before their proposed generation is added," she said. "That's not OK."

Grid-enhancing Technologies

Panelists also weighed in on the role of grid-enhancing technologies as a way to cut costs.

PJM's Seiler said the industry could benefit from a guide identifying where grid-enhancing technologies "would have the biggest bang for the buck."

"There's a lot of reluctance on behalf of our asset-owning utilities to apply grid-enhancing technologies, frankly, because of things like the reliability of the internet, security of [the technologies and creating an] additional avenue by which we could be attacked from a cybersecurity view.

"And these things have to be reliable. From a pure planning viewpoint, in my mind, there's very few grid-enhancing technologies that can be relied upon on a day-in, day-out basis where I know I can count on having that extra transmission capability.

"Things like dynamic line ratings can be applied on the physical transmission line to squeeze out a few more megawatts from a pure system operations view. From a planning view, I can't count on" them, he said.

Heinle disagreed, saying GETs should be part of regional planning. Distributed energy resources "served as a valuable planning tool in California a few weeks ago. And when you hear comments like, 'Well, we can't always count on this or that' — those were similar comments that we heard about solar [and] wind, not too long ago. We found ways to incorporate them into the grid, and to use them in our planning for resource adequacy."

Glick asked consumer advocates if grid planners give sufficient consideration to alternatives when local transmission projects are proposed.

CAPS' Poulos said there is not: "The transmission owners in the [PJM] region say, 'We have control of whether we're going to do grid-enhancing technology. You have no input on this.'" ■

Southeast

Duke Energy Estimates Net-zero Push at $145B in Next Decade

Numerous Factors Could Raise Cost or Slow Progress

By John Cropley

Duke Energy last week estimated the cost of its clean energy transition plans at $145 billion over the next decade, $10 billion more than its previous 10-year plan.

The majority of this investment in its seven regulated utilities — $75 billion — is projected to be for grid modernization. The rest would go to battery storage and zero-carbon power generation from solar, wind, hydro, nuclear and small modular nuclear ($40 billion); new natural gas generation and maintenance ($10 billion); natural gas distribution ($10 billion); and other expenses including coal maintenance, coal ash and corporate activities ($10 billion).

Hydrogen-enabled natural gas technology is included in the total, along with smart technology to detect potential problems and self-healing technology that limits the frequency and duration of power outages.

Duke said the 2023-2032 roadmap will support its efforts to reach more than 50% carbon reduction by 2030, 30 GW of regulated renewable energy by 2035 and net-zero carbon emissions by 2050. Its interim targets are 50% reductions in Scope 2 and Scope 3 upstream/downstream emissions by 2035 and an 80% reduction in Scope 1 emissions by 2040.

Specific 2050 targets include 28 GW of installed energy storage and 40% renewable power generation.

Explosives topple one of the stacks at Duke Energy's retired Crystal River Coal Plant in 2021. | *Duke Energy*

"These critical energy infrastructure investments will also provide substantial economic benefits, including job creation and tax revenue for essential governmental services in our regions," Duke CEO Lynn Good said in a *statement* accompanying the *economic* and *climate* reports released Oct. 4.

The economic report by consulting firm EY placed the direct and indirect benefit of Duke's plans at 20,000-plus jobs created and $250 billion in output during the 10-year period.

To limit the impact of all this spending on its 8.2 million electric and 1.6 million gas customers, Duke said it is investing to lower the cost and volatility of fuel; leveraging clean energy tax credits; transitioning to renewables that generate without fuel costs; and making changes to cut the cost of storm restoration. The recently passed Inflation Reduction Act will further reduce customer costs, it said.

Factors that will control the pace of investment include scalable supply chains; grid planning; and federal, state and local approvals.

Potential problem points include shortages of skilled labor or materials; slow evolution of numerous technologies that do not currently exist in scalable form; an insufficient or overly expensive supply of renewable natural gas; and site acquisition. For example, Duke's proposed Carolinas Carbon Plan calls for 12 GW of new solar installed in the next 13 years, which by a conservative estimate of at least 8 acres/MW would entail a 96,000-acre footprint.

Finally, state regulators must allow Duke to recover the costs of its investments from ratepayers, the company said.

Through 2021, Duke had reduced the carbon emissions of its generating fleet 44% from 2005 levels, in part through what it said is the largest planned coal fleet retirement in the industry. Duke expects coal to account for only 5% of its generation mix by 2030 and be eliminated altogether by 2035. ■

Duke Energy Kentucky's Walton Solar Power Plants 1 and 2 in Kentucky came online in 2018. | *Duke Energy*

CAISO/West News

Western Markets Exploratory Group Shares Views

By Hudson Sangree

TEMPE, Ariz. — The Western Markets Exploratory Group made a rare public presentation of its work assessing the pros and cons of organized markets in the West, including an RTO, at the Sept. 29 meeting of the Committee on Regional Electric Power Cooperation and the Western Interconnection Regional Advisory Body (CREPC-WIRAB).

The group's members include a loose coalition of some of the West's largest utilities, but its work has taken place largely in private since it began meeting in summer 2021.

Arizona Corporation Commission Chair Lea Marquez Peterson introduced and moderated the WMEG panel, consisting of Arizona Public Service CEO Jeff Guldner, NV Energy CEO Doug Cannon and Bonneville Power Administration CEO John Hairston.

"There are many options for pursuing greater collaboration among utilities in the West" to promote reliability and economic benefits, Marquez Peterson said. "One option that's been highly discussed is the creation of an RTO. I believe the regulators in this room would like to see an RTO, and certainly a great number of stakeholders would like to see that also."

Questions remain, however, about whether an RTO "will really provide more benefits than less expensive options," she said. In the meantime, "we should continue to investigate all opportunities for furthering collaboration between utilities and for strengthening our relationships with regulators in other states, like the approach with the Western Markets Exploratory Group."

WMEG is weighing options that include: CAISO's proposed extended day-ahead market (EDAM) for its real-time Western Energy Imbalance Market (WEIM); the potential for CAISO to expand beyond California and become an RTO; SPP's Markets+ program, a bundle of services that stops short of a full RTO; SPP's plans for an RTO West, an offshoot of its Eastern Interconnection RTO; and the Western Power Pool's Western Resource Adequacy Program (WRAP), a West-wide effort to ensure utilities have sufficient capacity to meet peak demand. (See *CREPC-WIRAB Weighs Western Transmission, Markets*.)

Guldner said WMEG members are interested in greater market efficiencies such as through CAISO's EDAM. Large Colorado and Nevada utilities are under legislative mandates to join an RTO by 2030, he noted. And WMEG has talked with CAISO about the possibility of an RTO, but CAISO's one-state governance remains a sticking point, he said.

"We began talking with the California Independent System Operator about … if we go to one large market, then we really need to address governance, because everybody was concerned about a California-dominated governance in a West-wide market," Guldner said.

"There are other options, and I just want to make one point really clear. None of the options would involve the rest of the West not trading with California," he said. "The question is just how that trading will occur. California has a massive load sink [that's vital] for our generation to be optimized. It's just whether that would be done directly as part of the California market or whether it would be done

A power line crosses Tempe, Ariz., where WMEG members spoke at the fall CREPC-WIRAB meeting. | *© RTO Insider LLC*

CAISO/West News

through seams agreements between two RTOs."

SPP's planned RTO West is another possibility, Guldner said.

WMEG was established to develop a "roadmap" for the West "up to and including a full RTO formation," with cost-benefit analyses for various options, he said. It now involves 25 entities, including Idaho Power, the Los Angeles Department of Water and Power, Public Service Company of New Mexico and the Western Area Power Administration. (See *Western Utilities to Explore Market Options*.)

BPA Viewpoint

BPA joined WMEG this year to get a broader understanding of "what's happening in [Western] markets," Hairston said. "We come to this discussion with about three-quarters of the high-voltage transmission in the Northwest, so quite honestly, any discussion about an RTO [or other organized markets in the West] has to involve Bonneville Power.

"We understand that, and we accept that responsibility," he said. "The thing is that when I come to these conversations, I'm bringing 140 some-odd customers with me, and so if you can imagine trying to pull all those different perspectives together and get us on one path, that's also challenging."

BPA began participating in the WEIM earlier this year and is seeing positive results from its first foray into an organized market, he said.

Now it is paying close attention to what's happening with the WRAP as it gets closer to starting operations, Hairston said. The program has signed up 26 participants, representing much of the Western Interconnection, notably absent CAISO. (See *Western Power Pool Board Approves WRAP Tariff*.)

"The next step for us really is looking at how we develop a resource adequacy program for the West," Hairston said. "And I think what's happening in the Western Power Pool [with WRAP] is exactly what we need. We're seeing the development of an independent governance structure, which I think could be the template for any other types of governance structures that we need as we entertain other markets. So, I'm really encouraged about what I'm seeing.

"Where else have you seen all of these utilities across the Northwest come together in this transparent nature to set up a program that's going to benefit all of us?" he said. "I think that in itself is an important step. I'm really glad to see that collaboration, and I think it is going to yield some positive results."

BPA next will join a day-ahead market, whether it is CAISO's EDAM or SPP's Markets+, and that could determine its eventual RTO membership, he said.

"Once you get into that extended day-ahead and you make those additional investments and that structure is developed, it's going to be really challenging to move after that," Hairston said. "And so, we have to get this next step right because that next step, I think, is really the foundational piece for an RTO."

"I think at the end of this thing there will be a Western RTO, [but] how [that looks] still remains to be seen," he said. "Is it one? Is it two? Those things have to be worked out, and that's going to have a lot to do with the qualitative piece: governance structures; how comfortable entities are in the development, whether it's through CAISO or SPP. You have to be comfortable with the governance structure you have and how you participate."

The other piece is quantitative, he said.

"There's a lot of discussion about the efficiencies gained under one Western RTO as opposed to maybe having several different [organized markets], but from my perspective, we really have to think about what is gained through some incremental efficiencies if the governance structure isn't what you want," Hairston said.

"So those are the types of questions we're trying to tackle, and I think WMEG allows us to work with a number of important utilities, understanding their perspective on the issues and making sure that we're factoring in all of the considerations as we make decisions and work transparently with our customers in making that decision," he said.

NV Energy Comments

Nevada's largest utility, NV Energy, was an early participant in the Western Energy Imbalance Market and has had a positive experience, CEO Cannon said.

The market has produced more than $2 billion in benefits for its participants since it started in 2014.

"Now, as we step forward into what's next in the state of Nevada … our thinking on market development [is motivated by] … what option we believe is going to be best for Nevada," Cannon said.

The state has plenty of solar power, like its neighbor California, as well as similar summer peaks, he said. Partnering with California won't be enough to deliver the diversity of resources — including hydropower from the Pacific Northwest and wind from Wyoming and Idaho — that Nevada needs to decarbonize its energy supply by 2050, as state law requires, he said.

Keeping ratepayer costs down while building infrastructure is another important consideration and will require market efficiencies to drive down energy prices, he said — a point also made by APS' Guldner. And NV Energy is working under a state mandate to join an RTO by 2030, he said. All are factors the company has to consider when deciding what markets to be part of going forward, he said.

"That's really what prompted us to look at an organization like WMEG," Cannon said. "Now we're up to 25 participants. We have 95 GW of peak load represented in that organization. We have geographic diversity. We have resource diversity. We have time diversity, so it starts to check a lot of those boxes that I talked about before," he said. "And so, I think it is a very useful organization to help us do some assessment … to understand what is ultimately the best outcome for investors." ■

West news from our other channels

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CAISO/West News

CREPC Seeks to Become an OPSI for the West

By Hudson Sangree

TEMPE, Ariz — The Committee on Regional Electric Power Cooperation (CREPC) is attempting to play a role in Western market formation like the one performed by the Organization of PJM States Inc. (OPSI) in the East, becoming a clearinghouse of information on organized markets and an adviser and advocate for states, especially those with understaffed utility commissions.

"One of the most pressing issues in the West today is the proliferation of forums in which market participants are developing and evaluating incremental steps towards regional electricity coordination — whether through energy markets, resource adequacy sharing, transmission planning or the leap to a full regional transmission organization," regulators and representatives from 14 Western states wrote in a *letter* sent to the U.S. Department of Energy in July, urging funding for the CREPC effort.

Current regional market efforts in the balkanized West include CAISO's proposed extended day-ahead market (EDAM) for its Western Energy Imbalance Market; SPP's planned Markets+ program, which also includes a day-ahead market; the Western Power Pool's Western Resource Adequacy Program (WRAP), a West-side RA initiative; and the Western Market Exploratory Group, a loose coalition of utilities assessing market options.

"Each of these efforts has multiple working groups with its own set of meetings," the letter said. "State utility regulatory commissions and energy offices often do not have the staffing levels, expertise or organizational ability to meaningfully participate in each of these market conversations — or sometimes even understand what is happening and how state interests may be implicated.

"Individual states have been working — somewhat unevenly across the region — to commit more time to regional matters, but acting now to support a collective effort to improve awareness and coordination among states will improve the outcomes of these dialogues," it said.

The Western Interstate Energy Board (WIEB), of which CREPC is a member committee, applied for $4.1 million in DOE funding to support the initiative to allow the committee play a greater role in educating and convening Western stakeholders as they weigh market participation.

A panel at the fall CREPC-WIRAB meeting that discussed CREPC's potentially expanded role included (from left) David Bobzien, Nevada Governor's Office; Colorado PUC Chairman Eric Blank; Michael Freeman, Montana Governor's Office; and Washington UTC Commissioner Ann Rendahl. | © *RTO Insider LLC*

"With support, WIEB could deliver a consolidated and consistently staffed forum for states to become educated on regional cooperation development considerations, to discuss issues among one another, and to inform or respond to emerging regional designs on an opt-in basis," the letter said.

A panel at last month's joint meeting of CREPC and the Western Interconnection Regional Advisory Board (WIRAB) weighed the potential for creating a regional committee for the West, similar to OPSI.

"With funding support from the U.S. Department of Energy, CREPC could deliver a consolidated and consistently staffed forum for states to become educated on regional electricity coordination, to discuss issues among one another, and to inform or respond to emerging regional designs," the *agenda* item for the panel said.

CREPC, established in 1982, is a joint committee of WIEB and the Western Conference of Public Service Commissioners, informally composed of state energy office officials and utility commissioners, that works to improve the efficiency of the Western grid.

David Bobzien, director of the Nevada Governor's Office of Energy, said on the CREPC-WIRAB panel that "I consider this to be the highlight of our proceedings. … It's been a long time coming for this discussion. There have been various conversations swirling about the West in recent months about how best to position, shape, guide [and] facilitate the conversation around markets in the West. And this is a proposal for how to answer that question."

Another panelist, Washington Utilities and Transportation Commissioner Ann Rendahl, called the DOE funding request crucial.

"Like many agencies and state commissions and even corporations, the Washington commission has lost some staff this year," Rendahl said. "We're trying to replace staff at a time when it's very difficult to get new staff. We are resource-constrained, and having the ability for this provides CREPC as an organization to more fully support states and answer some of these questions about these key market developments and aspects of markets."

She cited the comments of FERC Commissioner Mark Christie, who spoke in a prior session and emphasized the importance of a committee like OPSI as states wade into organized markets. Christie, a longtime utility regulator in Virginia, was a founding member of OPSI in the early 2000s as PJM grew into the nation's first RTO. The current discussion in the West about establishing a similar organization to inform and advocate for states' interests is a "critically important topic," Christie said. ■

CAISO/West News

BOEM Report Clears Way for 1st Calif. OSW Auctions

By Robert Mullin

A new finding by the U.S. Bureau of Energy Management (BOEM) means California could see its first offshore wind lease auctions by the end of the year.

The agency on Wednesday *issued* a finding of no significant impacts (FONSI) on marine and human environments from "offshore wind energy leasing activities" in the Morro Bay Wind Energy Area (WEA), located roughly 20 miles off the coast of San Louis Obispo County, about halfway between Los Angeles and San Francisco.

BOEM's environmental assessment (EA) of the WEA covers only the potential impact of the initial site "characterization" and "assessment" activities performed by offshore developers that are awarded leases for the three parcels within the area. Such activities could include surveys and extraction of core samples or the placement of meteorological buoys, the agency noted. The EA applies to the three parcels; associated rights of way, rights of use and easements; and the issuance of grants for subsea cable corridors and associated collector/converter platforms.

"The completion of our environmental review is an important step forward to advance clean energy development in a responsible manner while promoting economic vitality and well paying union jobs in Central California," BOEM Director Amanda Lefton said in a statement. "We will continue to work closely with tribes, state and federal partners, and key stakeholders to ensure any future development avoids or minimizes potential impacts to the ocean and other ocean users in the region."

But the agency pointed out that the FONSI does not apply to "the siting, construction and operation of any commercial wind power facilities," which would be subject to a different process.

"If BOEM decides to conduct a lease sale in the Morro Bay WEA, the bureau will develop an environmental impact statement (EIS) before approving the construction of any offshore wind energy facility in the Morro Bay WEA," the agency said in a press release. "That EIS will analyze the specific environmental consequences associated with the project, in consultation with tribes; appropriate federal, state and local agencies; and stakeholders and the public."

The agency's finding on Wednesday means that auctions for the three designated lease parcels within the Morro Bay WEA could proceed by the end of this year, in line with a schedule that BOEM offered in May when it announced a proposed sale notice for five lease areas off California, including two parcels in the Humboldt Bay WEA. (See *BOEM Issues Proposed Sale Notice for Calif. Offshore Wind Areas*.)

The Morro Bay WEA covers 376 square miles and is expected to accommodate up to 3 GW of wind resources. ■

BOEM issued a finding of no significant impacts for the Morro Bay offshore wind lease area of California's Central Coast. | *© RTO Insider LLC*

ERCOT News

TAC Faces New Normal in ERCOT's Stakeholder Process

Committee Honors Departing Member

By Tom Kleckner

AUSTIN, Texas — With ERCOT's Board of Directors having solidified itself as the new sheriff in town — and made up entirely of Texas residents — the grid operator's stakeholders are settling themselves into a lesser role.

Technical Advisory Committee members discussed weighty issues such as ERCOT's use of emergency response service (ERS) and how to handle priority revision requests from regulators, but they did not take any votes to resolve the issues.

Leading the meeting in Chair Clif Lange's absence, TAC Vice Chair Bob Helton set the tone when he recapped the board's August meeting, during which the directors overturned the committee's reduction of counterparties' unsecured credit limit to $30 million. Instead, the board eliminated unsecured credit limits, leaving ERCOT as the only U.S. grid operator without a cap.

"With that, I believe [the board] made it clear with the way the protocols are going to go is that we, as TAC and stakeholders, are an advisory function only, and not a control or authoritative function above the stakeholder process," Helton said during the Sept. 28 meeting.

Referring to TAC as "the collective wisdom of the market," Golden Spread Electric Cooperative's Mike Wise said during the conversation over priority requests that the committee needs to point out the unintended consequences in any revision requests it considers.

"We have to highlight those unintended consequences and do it in a passionate way, potentially to get the attention of those who do have the ability to make decisions, those that are in authority," he said. "We have in this case really no authority. Not limited, but no authority. And that means that this group right here has got to really engage and get to do so in an articulate way to get the attention of the decision-makers."

Legislation passed in the wake of last year's winter storm removed market participants from the ERCOT board. It also required the independent directors be Texas residents, eliminating potential candidates with deep market experience from across the country.

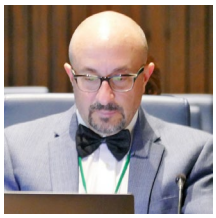
The board is currently considering *bylaw* changes that will further cement its decision-making authority at the expense of its corporate members. (See "TAC Passes on Bylaw Changes," *ERCOT TAC Considers Membership Requirements, Process Changes*.)

TAC members honored Clayton Greer with cakes noting his opposition to emergency response service. | © *RTO Insider LLC*

Members Honor 'OG' Greer

TAC members honored longtime peer Clayton Greer, who recently stepped down from the committee to return to designing substations.

Reliant Energy's Bill Barnes, wearing a bow tie "to reflect the occasion," referred to Greer, known for his opposition to ERS and for being willing to let everyone know, as one of TAC's "OGs" (original gangstas).



Bill Barnes, Reliant Energy | © *RTO Insider LLC*

"Here at TAC, we honor those that have made extraordinary contributions to our process and to our market design," Barnes said. "Our meetings will now be much more efficient and faster without Clayton's participation."

Several TAC members and their companies sponsored a BBQ spread after the meeting and a pair of cakes with the *Drake meme*, showing the rapper turning away from ERS but liking real-time co-optimization, a market mechanism still years away from implementation. A promised dunk tank "sponsored by a coalition of ERS providers" failed to arrive.

Greer, who participated in the meeting as an observer, couldn't resist getting his own digs in. During a discussion on ERCOT's ERS deployment practices, he said, "I just wanted to first thank you guys for having this today, because it certainly entertains me. I get that this is an antique program and we inherited it after a bad event in 2006, but it's time to revamp it."

Turning serious, Greer told members it was an honor to have served on TAC for two decades and offered support for the committee's new dynamic with the board.

"Over the last 20 years working on TAC and working with some of the brightest people in the industry, the faces may change, but the mission never did," he said. "It's always to provide the best product, market design and reliability design, and I think we did that. If you

ERCOT News

Clayton Greer chats with Oncor's Martha Henson during a break. | © RTO Insider LLC

ask any of the traders, they always want to trade ERCOT; it's one of the most liquid markets out there. And I think that's a testament to how well this body works.

"In the past, we've always had the stakeholders on the [ERCOT] board, so there was always that knowledge on the board," Greer added. "I think the new board members are really eager to understand how the market works and why a lot of these decisions are made because sometimes, that's opaque. Usually there's an underlying reason why things are the way they are [and] why they've been the way they've been for the last 10 years, and helping those guys understand that, I think, it's one of the goals to this body."

Members honored Greer with a standing ovation before adjourning for lunch.

TAC Approves 10 Change Requests

The committee approved, separately and as part of the combination ballot, 10 revision requests and a list of the system's 258 major transmission elements.

Luminant voted against a nodal protocol revision request (*NPRR1084*) that would allow ERCOT to publicly provide information about resources' forced outages, forced derates and start-up loading failures in a more complete and timely manner. The generator said it had concerns it wouldn't be able to comply with the change without an update to the outage scheduler. The NPRR passed by a 26-1 vote, with two abstentions.

Shell Energy abstained from *NPRR1058*, which passed 29-0. The NPRR would require quicker updates by qualified scheduling entities to the telemetered resource status, high sustained limit (HSL), and other relevant information, improving the physical responsive capability calculation's validity and dispatch.

The combination ballot included four NPRRs, two revisions to the Nodal Operating Guide (NOGRRs) and two system change requests (SCRs), which if approved by the board would:

- *NPRR1118*: clarify the outage schedule adjustment (OSA) process to improve the terminology and clarifies the process for issuing advanced action notices and OSAs, and to clarify offer submission and reliability unit commitment (RUC) procedures after an OSA is issued.
- *NPRR1127* and *NOGRR241*: clarify which entities are required to have hotline and 24/7 communications with ERCOT, and requires those entities answer each hotline call to proactively ensure situational awareness during emergency situations.
- *NPRR1139*: replace the usage of the wind-powered generation resource and photovoltaic generation resource productions with the HSL of an intermittent renewable resource as reflected in the current operating plan.
- *NPRR1140*: permit generation resources to recover their fuel costs when instructed to start because of a RUC and operate above the resource's low sustained limit.
- *NOGRR242*: update references from point of interconnection to point of interconnection bus.
- *SCR820*: build on the hotline communication process by developing a web-based platform supporting real-time, bidirectional, "send-review" messaging between ERCOT operators and transmission operators during emergency event coordination.
- *SCR823*: request that ERCOT process (upload) a flat file received by ERCOT from each affected transmission/distribution service provider (TDSP) that contains all the TDSPs' electric service identifier (ESI), besides retired ESIs. This flat file would allow all retail electric providers to have county names associated to all ESIs on the very first day following Texas SET V5.0 production go-live through the TDSPs' ESI extract that is produced daily by ERCOT. ■

— Tom Kleckner

ERCOT News

Overheard at GCPA's 37th Fall Conference

Vegas Eager to Take Up Torch from ERCOT Predecessors

By Tom Kleckner

AUSTIN, Texas — The Gulf Coast Power Association's 37th annual fall conference, held in-person for the first time in three years, drew 685 registered attendees here last week. Strangely, that was the exact number of registrations the GCPA had for the same event in 2019.

When not renewing friendships and sharing handshakes and embraces with those they hadn't seen in years, attendees were treated to panel discussions among lawmakers, market participants and industry experts on the ERCOT market, an oral history of the Texas grid operator, and a reenactment of the historical debates between Abraham Lincoln and Stephen Douglas.

Bill Flores, ERCOT | *© RTO Insider LLC*

Taking it all in was freshly minted ERCOT CEO Pablo Vegas, a surprise guest to the proceedings in just his second day on the job. He was shepherded during the conference's first full day by Bill Flores, vice chair of the ISO's Board of Directors. Vegas listened intently as the Joneses — Sam, ERCOT's first CEO; Brad, its retiring interim CEO; Liz, Oncor's regulatory affairs lead; and Dan, a respected energy consultant who helped create Texas' competitive market — reminisced about their roles in ERCOT's various market designs and how often their paths crossed at the ISO, Public Utility Commission and elsewhere in the industry.

New ERCOT CEO Pablo Vegas chats with retired TXU, now Vistra, exec Mike Greene. | *© RTO Insider LLC*

Calpine CEO Thad Hill delivers keynote address to GCPA's 37th Fall Conference | *© RTO Insider LLC*

Vegas seemed aware of the high expectations he faces and the responsibility he is undertaking.

"To think about the history of this institution that I'm now going to have the privilege to lead … each of the leaders up there have played a significant role in making and [preparing ERCOT for change]," he told *RTO Insider*. "It's not so much a passing of the torch but just continuing to make sure that we all understand where it's been, why it's lit, and why that's important.

"It's just exciting to be a part of the next big change and big evolution that ERCOT has been going through, decade after decade over the years, and it's great to be a part of this one. I can tell that there's going to be a lot of help from the industry, a lot of suggestions, and I'm just looking forward to working through all of those together with such a great team."

Introduced by Flores for a few opening comments to the audience, Vegas said he was "thrilled … honored and privileged" to be joining Team ERCOT and that he looked forward to working with the "incredible professionals" in the ballroom. Vegas invited those he did not know from an earlier stint in Texas to come meet him. (See *Vegas Plans to 'Engage Heavily' in ERCOT Changes*.)

"All I can say is, 'Wow, what a time to be coming back into Texas,' with what's going on in the market and what's going on in the economy," he said. "I can't remember a more exciting time to be in this industry."

Flores Says Vegas 'Checked All Boxes'

Flores, who led the ERCOT board's search committee for Jones' successor, told *RTO Insider* that Vegas checked all the boxes the group was looking for. He said Vegas stood out early after the committee initially identified 107 candidates to become the grid operator's fifth full-time CEO.

"It quickly came down to a small handful of people. We were looking for somebody with an engineering technical background, somebody with good leadership attributes, including a selfless servant leadership style. We were looking for someone who had senior executive experience … and to a lesser extent, somebody who already had experience with the Texas market," Flores said, nodding to Vegas' two years as COO of American Electric Power's AEP Texas subsidiary.

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Told that it appears he has been a quick learner of ERCOT's operations and functions, Flores said, "I've been a real nerd about this.

"I've read a lot of books; I have listened to tons of podcast. I spend a lot of time with Woody [Rickerson, ERCOT's vice president of system planning and weatherization] and the gang, and I'm still not done yet."

A five-term Republican member of the U.S. House of Representatives, Flores was appointed to the ERCOT board last year and serves as its vice chair. A certified public accountant, he has a background in the oil and gas industry. During his keynote address, Flores warned of the danger of relying on a single fuel, as Europe has discovered with Russian natural gas after its invasion of Ukraine. However, he also noted he is the largest residential solar user in his home county, and he extolled an "all-of-the-above" approach to ERCOT's fuel mix.

"One of the things I've noticed in environmental analysis today is that when you look at fossil generation, it's looked at from end to end," Flores said. "When you're looking at other forms of generation, it's just from when you turn it on to when you turn it off. Every source of generation needs to be looked at end-to-end on the environmental and emission scale.

"The bottom line from a policymaking perspective is that we need all-of-the-above solutions that have balance, that follow the laws of nature with respect to electricity, that follow the laws of economics," he said. "We'll have better policy outcomes when we follow those laws, versus what we as humans think we can do."

GCPA Members Honor Jones

GCPA members and conference attendees honored Brad Jones with an extended standing ovation after his panel discussion with three other Joneses ended.

GCPA President Mark Dreyfus, who represents commercial consumers on ERCOT's Technical Advisory Committee, recalled his more-than-25-year association with Jones. It began when Dreyfus was a PUC staff member and Jones was the "lowest guy on the totem pole" for TXU, Vistra's predecessor.

"His job, as far as I could tell, was to chase after us following a PUC open meeting to find out exactly what the commissioners had decided so he could report back," Dreyfus said. "I really liked that Brad Jones back then."

Jones rose through the ranks at TXU and played an integral role in designing ERCOT's competitive market. Like Dreyfus, Jones presided over GCPA. He joined ERCOT as

Brad Jones (second from right), flanked by Oncor's Liz Jones and former ERCOT CEO Sam Jones, listens as GCPA President Mark Dreyfus recounts a 25-year association between the two. | © *RTO Insider LLC*

COO and then "packed up his cowboy boots," as Dreyfus said, and left Texas for a short stint as NYISO's CEO.

"But I know he was lonely for home and family," said Dreyfus, who visited Jones in Albany, N.Y. "He treated me like family and treated me to an insider's tour of the city: well-cooked sirloin, beer pong and a reggae show."

Jones left NYISO in 2018 and retired to his home in Austin. That is, until the February 2021 winter storm came within minutes of collapsing the Texas grid, leaving ERCOT and the industry in "disarray," as Dreyfus put it.

"Who would step up and take on the responsibility of leadership? I can't think of anyone other than Brad, who brought his experience in the industry, experience in the New York ISO, and that demeanor he has which is so successful with our industry members at the legislature and with the membership of GCPA," Dreyfus said. "We don't have a gift card or flowers or custom GCPA cowboy boots, but we do have a reception immediately following where I hope you will take a minute to thank Brad."

Jones could do little more than laugh and nod his head in appreciation.

"Brad has done a great job of readying ERCOT for this next level of change," Vegas said after the applause settled.

"[Jones] stepped up at a really critical time for the 26 million Texans that are served by the ERCOT part of the Texas grid and to help keep the team together," Flores said. "He worked with policymakers and regulators to keep the lights on, so we owe him.

McAdams: Give Market-based Solutions a Chance

Will McAdams, Texas PUC | © *RTO Insider LLC*

PUC Commissioner Will McAdams gave the conference attendees a sneak preview of the commission's proposed Phase II market design, which the commission continues to plan for a mid-November release. He said the commissioners recognize that the grid of the "very near future" will consist of more renewable and intermittent resources than dispatchable capabilities.

"And that's fine. We believe, I believe, to cover the variability of intermittent output, we must ensure that sufficient quantities of dispatchable power cover system needs during forecasted high risk periods," he said in a keynote address. "This serves as the basis of

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what we're discussing now. This will allow us to reduce our out-of-market actions like [reliability unit commitments] and replace them with market-based solutions. [As other speakers suggested], this framework will be based on market principles, which I hope will represent the consensus of the commission."

McAdams said the Phase II market adjustments will encourage dispatchable generators to maintain their facilities, and, if necessary, to replace retiring units with new generation. But, he reminded his audience, the PUC can't guarantee that new generation will be built.

"We can influence markets, but we cannot command them to deploy capital," McAdams said. "If policymakers believe that they require a guarantee that new generation be built in order to meet growing system demands, then a policy must be taken up and considered by the state legislature. It is a crossroads … one route stays the course with markets and market-based solutions. The other would instruct the PUC to assume a more command-and-control posture in how electricity is generated and delivered within ERCOT."

Historically, markets, collective viewpoints and their stakeholders are best suited to adapting to changes, he said.

"As such, I believe that the best way to restore the public's trust and confidence in our grid is for the public utility commission, ERCOT and our market participants to work together to demonstrate that we can build a policy to achieve maximum grid reliability," he said, "and at a sustainable cost level to Texas consumers that may endure challenges by the naysayers and detractors and demonstrate to the legislature that this is a market worth saving."

Texas Politicos Wait on ERCOT Redesign

Count Texas lawmakers among ERCOT stakeholders who are looking forward to the PUC's release of its Phase II market design, expected in mid-November. The Texas legislature opens its five-month biennial session Jan. 10, and legislators have asked to vet the PUC's market design before the ISO's staff begins to implement it. (See *Texas Lawmakers to Vet ERCOT Market Redesign*.)

"For the most part, we're all waiting for the next big change," State Sen. Nathan Johnson (D) said, noting discussions taking place within several Texas energy advisory and reliability committees. "I don't mean to be dismissive of it being a lot of talk, but because it's a very important conversation, but we have yet to see the results from it. We have a variety of perspectives. We have competing viewpoints … but as we move into the legislative session, and as we come out of the legislative session, we're going to have to have some clarity."

Johnson said legislators, who passed several laws related to the grid's near-collapse during last year's winter storm, expected the market design to have been further along that it is now. (See *Abbott Signs Texas Grid Legislation into Law*.)

"As much fun as it is, this is hard. We don't have the answer yet," he said. "We need the confidence of the investors. We're not going to get there with a bunch of day-ahead ancillary services. We're going to see some form of a capacity market in our energy-only market. There's going to be an element of predictability and an agreed-upon predictability standard."

State Rep. Phil King (R), who represents a gas-rich district, said electric power has been the most complex, competitive and diverse issue he has dealt with in his 24 years at the Capitol.

"I think this is going to be the second most substantive change we've made in how we do all this since 1999 … we created a competitive market that was the envy of the world," King said, referring to Senate Bill 7 that deregulated ERCOT's wholesale and retail markets.

"From my perspective, it's how do we make sure that we have enough gas-fired generation that can be built in a way that companies can make a reasonable profit? But how do we incentivize building enough gas-fired power without stepping over that line and entering back into a regulatory market?" King asked. "Renewables have a big place in Texas. I think we can have a really hard discussion about how much that is. Relative to the amount of dispatchable electricity, I think there's too much. And so how do we incentivize from a financial perspective and a regulatory perspective for gas-fired plants to be built without stepping off that cliff and losing the competitive market?"

State Rep. Phil King shares his thoughts on ERCOT's market redesign as State Sen. Nathan Johnson listens. | *© RTO Insider LLC*

Rep.Donna Howard | *© RTO Insider LLC*

"We have to be agnostic about the future," countered State Rep. Donna Howard (D). "Obviously, we need to have resiliency, and we need to have reliability. It needs to be affordable. We need to have dispatchable [generation] and we need to have predictability. We know that renewables, of course, are predictable [to forecast]. Gas is volatile. We are so fortunate to have the thermal resources that we have … We want to make sure that whatever the market redesign ends up being, that it is going to incentivize whatever it is that will give us the power we need when we need it."

Lincoln-Douglas? Try Barnes-Stover

Bill "Honest Abe" Barnes, NRG | *© RTO Insider LLC*

Apex Clean Energy's Mark Stover and NRG Energy's Bill Barnes did their best to recreate the famed 1858 senatorial debates between Abraham Lincoln and Stephen Douglas, albeit in condensed form. Rather than conduct seven three-hour debates, the two settled for a 30-minute discussion over whether transmission planning and regulatory reforms to relieve congestion are compatible with regulatory design changes to retain and incentivize dispatchable generation in ERCOT's energy-only market.

"I have made many sacrifices throughout my career for the entertainment of the GCPA audience. This might be a new low or new high, so I hope you guys appreciate this," Barnes said, donning a fake beard and what passed for a stovepipe hat in his role as Honest Abe. "Abraham Lincoln was like nine feet tall, so you're going to have to use your imagination."

"Bill definitely wins the costume category," admitted Stover, who wore a vest and a long coat. "But at the very least, Bill and I got a jump on our Halloween shopping this year."

Stover, Apex's director of state affairs, said in his address that market design and transmission reforms are compatible. If done right, he said, ERCOT's transmission planning process "can actually bolster our efforts to increase reliability on the ERCOT system, something every stakeholder wants, including the renewable energy sector."

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"If the transmission projects can deliver new wind, solar, storage and, yes, natural gas paired with something that we don't talk a lot about, increased efficiency and demand response, we can deliver the same amount of power or more at a lower cost than existing fossil assets or new planned large thermal assets," Stover said. "We need to move away from our just-in-time regime, which is increasing costs on consumers and unnecessarily straining our power grid and keeps a range of benefits from flowing to consumers."

"Hogwash!" Barnes, NRG Energy's senior director of regulatory affairs, bellowed after Stover's close.

"Transmission planning processes and regulatory reforms that create preference for transmission development fundamentally conflict with the foundational principles of an energy-only market and work to defeat the incentives to retain and attractive dispatchable resources," Barnes said. "Transmission congestion is a design feature of LMP-based markets, not an excuse to endlessly build more transmission lines. These deliberate pricing differences allow for the competitive market to address transmission bottlenecks through redispatch of generation and, if allowed to persist, through private investment, rather than regulated costs to captive ratepayers."

The audience judged the debate a draw. Douglas narrowly won election to the Illinois U.S. Senate seat up for grabs after the debates. Two years later, though, Lincoln won the big prize when he defeated Douglas in the 1860 presidential election.

Vistra's Haley Receives GCPA Award

Ian Haley, Vistra | © RTO Insider LLC

GCPA presented Vistra's Ian Haley with its emPOWERing Young Professionals Award, as selected by the organization's board. The award is presented annually to an individual under the age of 40 who has achieved excellence in the power industry, making unique contributions to the success of the electric power market and serving as a role model and leader for others.

Vistra's senior director of regulatory policy, Haley was described as "an ardent participant in the stakeholder process." He represents Vistra subsidiary Luminant on TAC and works on several other ERCOT committees, vice chairing the Supply Analysis Working Group.

"I cannot tell you how much I appreciate this," Haley told the audience. "I'm deeply honored, even though quite a few of you have told me there's no way I'm under 40. I feel extremely fortunate to work in an industry that I find so interesting and have the opportunity to work with so many people I consider friends."

"He's a fellow Tulane graduate," Vistra CEO Jim Burke said in introducing Haley. "You probably didn't read that in the bio, but good people come out into Tulane University."

"Ian has a knack for reaching out across the aisle in the ERCOT stakeholder process and is an adept negotiator," Ned Bonskowski, Vistra's vice president of Texas regulatory policy, said in a *statement*. "Some of his strongest work is when he is forging consensus across disparate stakeholders on contentious issues."

The award's nomination criteria includes career progress, industry involvement, leadership development, role model for other young professionals, and expertise, passion and the ability to inspire others. ■

ISO-NE News

New England's Gas Industry Frets About Cracks in Electric Side

By Sam Mintz

FOXBOROUGH, Mass. — As New England's gas and electric providers and regulators prepare for another dicey winter, gas industry representatives threw out solutions ranging from market fixes to upgraded pipeline infrastructure at a daylong gathering Sept. 29.

The Northeast Energy and Commerce Association's Fuels Conference focused heavily on the fuel supply challenges that continue to bedevil the Northeast in winter.

ISO-NE recently said that the Everett LNG facility must be maintained for grid reliability, even past 2024 when its anchor tenant, Mystic Generating Station, is set to retire. (See *ISO-NE: Reliability Still Depends on Mass. LNG Import Terminal*.)

That's narrow-minded, argued an executive for one of the other LNG import terminals that helps brings gas into New England.

"The solution needs to be a market fix that resolves the mismatch between how LNG is contracted for and how generators are compensated, not another subsidy for a singled-out facility," said Karen Iampen, vice president at Repsol, which operates the Saint John LNG terminal in New Brunswick, Canada.

She called the previous actions by ISO-NE "Band-Aids" that don't address the region's larger issues.

"Removing this obstacle to more long-term contracting is the most economic way to ensure fuel security by bringing in more cargoes that more fully utilize the storage and send-out facilities at the LNG terminals," Iampen said.

Pipelines Want to Build Out

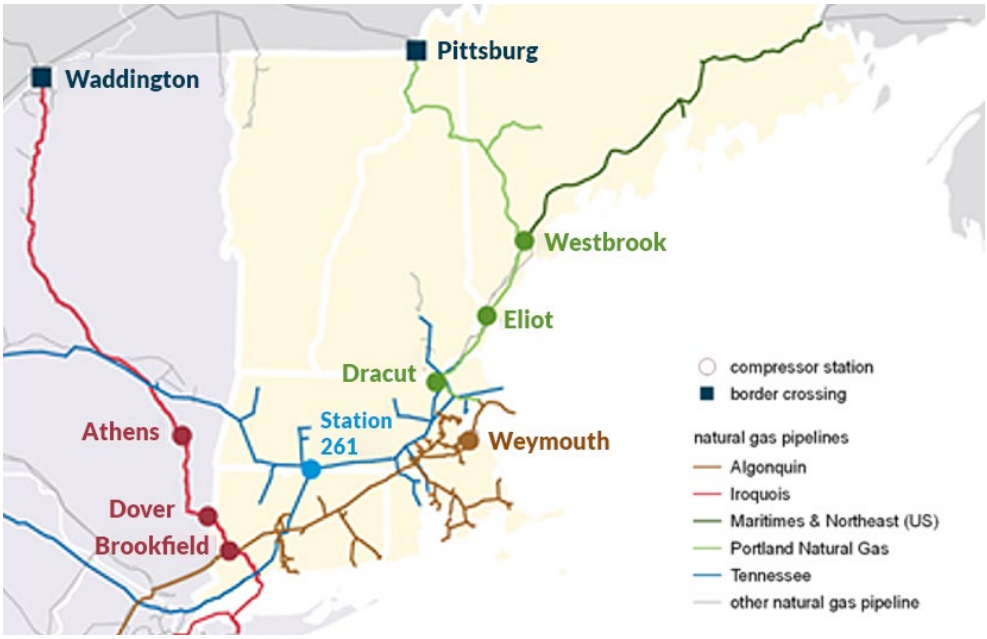
The other way to get more gas into the region is by land, and pipeline companies think that they'll have a key role to play in New England even as renewables ramp up.

"Renewable growth requires operational flexibility," said Jim McCord, account director at Kinder Morgan.

He pointed to California, where natural gas systems have helped back up rapidly growing renewable penetration by increasing or decreasing output when necessary.

"As an industry, natural gas will work hard to play this critical role in ensuring energy reliability," McCord said.

Nobody is trying to build new pipelines to New England, but the existing ones could use upgrades, said Michael Dirrane, director of marketing for Enbridge.



Natural gas projects in New England | *EIA*

"I'm advocating for brownfield pipeline projects, where we take out the smaller diameter pipe and replace it with higher diameter pipe, and perhaps add some additional horsepower on the system," Dirrane said.

Those improvements would have minimal impact on the environment or to landowners, Dirrane said.

"That is the best way to drive down costs in New England."

Tom Lockett of TransCanada said his company also is eyeing brownfield expansion.

LDCs Worried

Meanwhile, the utilities are increasingly concerned that reliability challenges facing the electric system in New England this winter could threaten the gas side too.

National Grid Director of Gas Supply Planning Elizabeth Arangio | *© RTO Insider LLC*

Elizabeth Arangio, director of gas supply planning for National Grid, said that the "dots are connected."

"We don't want anything to happen on the electric side," Arangio said. "Certainly it will impact us."

"It's an unfortunate situation. It's not a good situation," said John Rudiak, senior director of energy supply for Avangrid (UIL).

He called it a "spillover risk" that in particular could affect low-pressure gas customers.

"There's a risk that if there were rolling blackouts, when those blackouts are restored, the gas lines could [face] reduced pressure" if not managed correctly, Rudiak said.

Eric Soderman, Eversource's director of gas supply, echoed that fear.

"While the [local distribution companies] have adequately planned to serve their customers for this winter, as they do each winter, we have concerns that a cascading effect in New England could affect lower pressure areas on the pipeline that are extended laterals or don't have backfeed areas," Soderman said.

From the LDCs, the dominant feeling is frustration about how the electric side has been handled.

"The bottom line on this one is I feel comfortable about our companies, in terms of our preparation, in terms of our resources and our infrastructure and our capabilities," Rudiak said. "But I'm really disappointed in [ISO-NE] not having solved the problems of market design and fuel supply reliability after so long." ■

ISO-NE News

Mystic Cost Worries Highlight NEPOOL PC Meeting

Committee Approves ICR for FCA 17, ISO-NE Budget

By Sam Mintz

A group of New England suppliers is raising worries about the costs of the cost-of-service agreement between ISO-NE and the Mystic Generating Station heading into what many believe could be the priciest winter for gas in recent memory.

In a *letter to ISO-NE officials* dated Sept. 29, the group of load-serving entities pointed to the high costs of the agreement for its first few months of existence this summer: $13 million for June and $48 million for July. Heading into this winter, they warn, the "costs could balloon to levels not contemplated in 2018," when the agreement was put into place.

The suppliers said they don't take issue with the need for the agreement, which is staving off the retirement of Mystic, a critical gas-fired plant in Connecticut, until 2024. But they do want to try to protect themselves and consumers from the costs of the program.

"We have grave concerns regarding the winter months, when gas prices will be at their highest, and the costs that we could face under the agreement," the companies wrote. "No one in 2018 could have predicted how much more volatile and unmanageable hedging these costs would become considering world events."

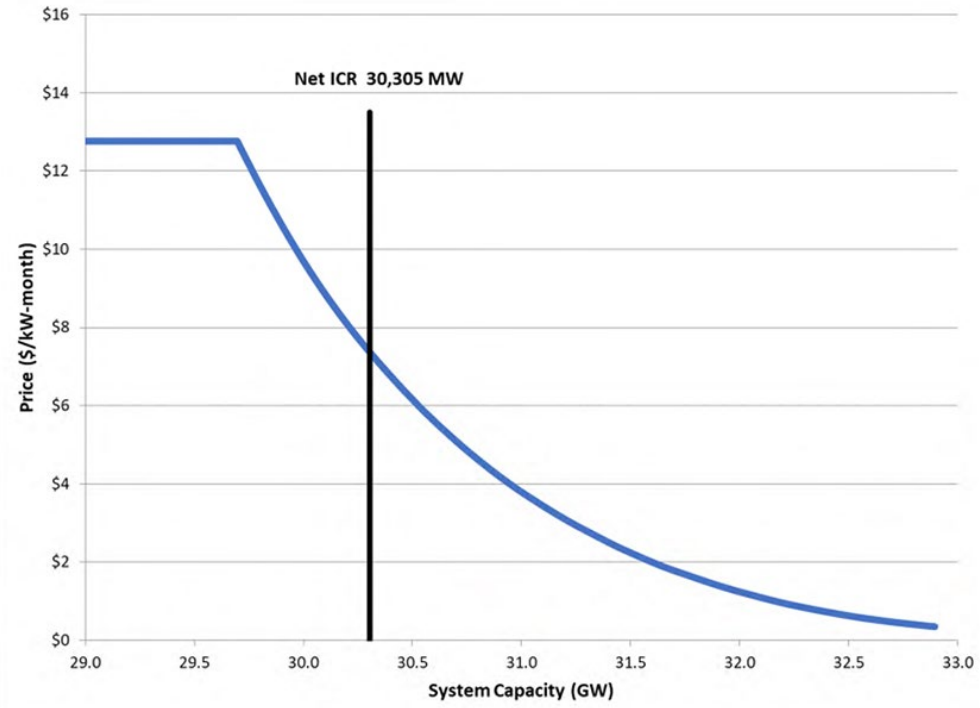
To try to manage the risk, the companies asked ISO-NE to provide more information and transparency about the agreement, including a cost estimate for the whole agreement and a cost estimation worksheet for its first months.

"The LSE group recognizes the challenges ISO-NE has faced that led to the Mystic COS agreement and the hard work that ISO-NE is doing to prepare for this winter," they wrote. "The primary goal here is not to thwart those efforts but instead to work together to mitigate the costs associated with the Mystic COS agreement as much as possible."

The companies are Brookfield Renewable Trading and Marketing, ENGIE Energy Marketing, NextEra Energy Marketing, Shell, Vistra and Vitol.

At the NEPOOL Participants Committee meeting on Thursday, ISO-NE COO Vamsi Chadalavada promised that the grid operator will work with them.

"ISO understands and appreciates the gravity of the situation," he said.



The systemwide demand curve for the 2026/2027 capacity commitment period | *ISO-NE*

The Mystic Generating Station remains at the center of conversations about reliability and cost in New England. | *Shutterstock*

Chadalavada said ISO-NE experts will present on the administration of the contract at the Markets Committee this week. He also said the grid operator is planning to do a scenario analysis to help inform cost estimates for the winter months. And he said the RTO is reaching out to LSEs, states, consumer advocates and transmission owners to talk about possible changes to cost allocation for the second year of the agreement.

Other PC Action

It was a busy day for the PC, which also saw a number of significant votes and presentations.

Chadalavada presented the latest iteration of the RTO's *2023 work plan*, which includes intensifying focus on the development of a day-ahead ancillary services market and resource capacity accreditation. Both will be regular topics of NEPOOL meetings in the coming months, and the grid operator is planning to file to FERC on both by the end of 2023.

Work on energy adequacy, including considering changes to the Inventoried Energy Program, is another highlight.

The committee also approved ISO-NE's proposed installed capacity requirement values for Forward Capacity Auction 17, despite longstanding stakeholder frustration over the methodology for calculating ICR and the assumptions about imports from New York.

The approved ICR for the 2026-2027 capacity period is 31,306 MW, and the net ICR is 30,305 MW.

The PC also signed off on the 2023 budgets for ISO-NE and New England State Committee on Electricity.

And stakeholders approved a rule change that would allow storage-as-a-transmission-only-asset projects in New England. (See *ISO-NE Weighs Allowing Storage as Transmission*.) ■

MISO News

MISO, PJM Down to 2 Possible TMEPs

By Amanda Durish Cook

| © RTO Insider LLC

MISO and PJM halved their shortlist of potential smaller interregional transmission projects down to two but warned that even those project benefits might be too small to proceed.

The RTOs staffs presented the two contenders Oct. 3 during MISO-PJM Interregional Planning Stakeholder Advisory Committee meeting. The potential targeted market efficiency projects (TMEPs) are line work on the 138-kV Powerton-Towerline flowgate in central Illinois and a potential fix for the congested 138-kV Chicago-Praxair flowgate near the Chicago area. (See *MISO, PJM Consider 4 Small Interregional Projects*.)

The grid operators studied 23 flowgates accounting for $328 million of congestion costs during 2020/21 in this year's TMEP process.

PJM's Nick Dumitriu said analysis is still underway and said the two remaining projects won't necessarily be eliminated. He said the RTOs are still comparing anticipated project costs against the first four years of estimated project benefits.

"It's premature to say there won't be a TMEP," he said, predicting that "at least" one project could still be recommended to the RTOs' respective boards of directors by the end of the year.

Stakeholders have asked the grid operators to consider raising the $20 million TMEP cost threshold given continued inflation and supply chain issues.

TMEP projects must cost less than $20 million, completely cover installed capital cost within four years of service, and be in service by the third summer peak after their approval. The projects are assessed using a shorter time horizon than interregional market efficiency projects.

MISO and PJM have approved three small TMEP portfolios since 2017 and one larger *interregional market efficiency project* in 2020.

This summer, WEC Energy Group's Chris Plante asked the grid operators to consider creating a joint targeted interconnection queue study similar to that undertaken by MISO and SPP. That work has resulted in identifying about $1 billion of projects on their seams. (See *MISO, SPP Propose 90-10 Cost Split for JTIQ Projects*.)

"We are very encouraged by the progress with SPP and would like to see a similar initiative with PJM," Plante said. ■

MISO News

FERC Rejects Proposal for Penalty-free Load Exits from MISO

By Amanda Durish Cook

FERC last week rejected the Coalition of MISO Transmission Customers' (CMTC) proposal to allow some load to exit the MISO system penalty-free given the current Midwestern capacity shortfall.

The commission on Oct. 3 said CMTC failed to prove that MISO's current tariff practices are unjust and unreasonable just because they don't contemplate allowing load to bow out when the capacity auction fails to procure enough supply (*EL22-60*).

CMTC argued before FERC in May that MISO should allow its customers to decrement their load without being charged capacity payment obligations to lessen the possibility of summer blackouts. (See *MISO Customers Ask for Penalty-free Load Reductions*.)

The group said reductions in load would help following MISO's 2022/23 Planning Resource Auction (PRA), which unveiled a 1.2-GW capacity shortage across MISO Midwest, triggering a $236.66/MW-day cost of new generation entry (CONE) clearing price for the entire subregion. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

CMTC contended that when a deficit occurs, MISO should allow some load to depart the system to avoid the steep capacity prices and bolster reliability by trimming demand. The group suggested that the RTO could allow load exits up to the 1.2-GW auction shortage and stop accepting any further load reductions once the supply and demand imbalance is resolved.

But FERC said that CONE clearing prices are an intentional feature of the auction — not a bug — beckoning new resources into the market.

"We are not convinced that the 2022/2023 auction results constitute a change in circumstances," the commission wrote.

FERC said load-serving entities have ways of hedging against high auction prices, including entering bilateral supply contracts ahead of the auction, "supporting the development of new facilities" or selling demand response capabilities.

"The ability to hedge against high auction prices and the various off-ramps from the auction is further evidence that the existing tariff provides opportunities to avoid potentially high prices in the auction and is not unjust and unreasonable as complainants claim," FERC said.

Callaway Energy Center | *Ameren Missouri*

The commission also said it wasn't convinced that CMTC's proposed solution would be just and reasonable. It said giving auction participants the chance to "shed an otherwise binding commitment after an auction is conducted" would undermine the auction's prices that signal for resource planning and investment.

In a separate concurring opinion, Commissioner James Danly repeated concerns about the flood of intermittent resources in MISO's interconnection queue and its dwindling dispatchable generation. He called the RTO's current market design "inadequate to the task of procuring sufficient capacity."

However, he admitted that the 2022/23 PRA functioned as intentioned "regardless of poor decisions by market participants or the long-term consequences of systemic defects in MISO's capacity construct."

"Why observers of MISO would shriek and clutch their pearls when the price rises to CONE in the event of a capacity shortfall … is beyond me. Anyone who gets upset about prices rising in times of scarcity cannot truly be a proponent of competitive markets," Danly said.

MISO itself argued that processing and then resettling "a multitude of load exit requests" would be burdensome and require compliance controls. It said it foresaw "complex computation" and "needless litigation" if FERC greenlit penalty-free departures.

The RTO said it would likely be forced to replicate the auction with new levels of load so it could establish updated demand forecasts, different systemwide and zonal reserve requirements, and adjusted zonal resource credits. It said CMTC was oversimplifying a solution.

MISO's Independent Market Monitor said CMTC's complaint was "fundamentally incompatible with MISO's market design and tariff."

The Coalition of Midwest Power Producers added that CMTC was essentially seeking retroactive ratemaking and said if FERC granted the complaint, it would have "eroded investor confidence in all regional transmission organization/independent system operator markets and would also represent a disruptive precedent that others could seek similar cost avoidance." ■

MISO News

Regulators, LSEs Ask FERC to Reconsider MISO's Seasonal Capacity Accreditation

RTO Seeks Rehearing of Minimum Capacity Obligation Rejection

By Amanda Durish Cook

Multiple stakeholders are seeking a FERC re-evaluation of MISO's approved seasonal auction design, arguing that the plan's capacity accreditation based on generators' past performance is untested and unfair.

The Louisiana and Mississippi public service commissions said that while they don't "in concept" oppose capacity accreditation rules "based upon some measure of historic generator performance," MISO didn't provide evidence to back up its availability-based accreditation.

They acknowledged that FERC defers to and gives grid operators latitude in designing their markets.

"But when the vast majority of utilities and many state regulators, with thousands of years of cumulative experience regulating utilities and serving retail customers, vociferously object to an expensive, untried, untested and unmodeled market experiment that is highly unlikely to address the resource adequacy concerns developing in MISO, FERC needs to listen," the state commissions wrote.

FERC in late August gave MISO the go-ahead to establish four seasonal capacity auctions — with separate reserve margins by 2024 and apply a seasonal accreditation based on a generating unit's past performance during tight system conditions. However, the commission disallowed MISO's proposal to institute a minimum capacity obligation, in which a load-serving entity must demonstrate that it has secured at least 50% of the capacity required to meet their peak load in advance of the RTO's voluntary capacity auctions (ER22-495 and ER22-496). (See *FERC OKs MISO Seasonal Auction, Accreditation*.)

Consumers Energy said the availability-based accreditation will breed "unreasonable volatility for market participants and increased costs to customers without demonstrated reliability benefit." The company asked FERC to consider delaying implementation until the 2024/2025 planning year if it chooses to let the accreditation design stand.

DTE Energy and Alliant Energy seconded Consumers' claims that the accreditation will aggravate volatility and raise costs. They called the design a "flawed and insufficiently supported approach that will handicap prudent planning practices by stakeholders."

Entergy, Cleco Power and other MISO South electric cooperatives said the accreditation will yield "large and unreasonable fluctuations in accredited capacity from one season in one year to the same season in the next year." They said LSEs stand to lose "significant capacity value" in one season based on performance during one or two days with small operating reserves.

The MISO South stakeholders also took issue with the RTO's 31-day outage limit in a given season. They said the rule "places unreasonable limits and costs on a utility that wishes to engage in prudent maintenance practices at times when sufficient resources are expected to be available to maintain reliability."

The Clean Energy Coalition — which includes Clean Grid Alliance, Sierra Club, Natural Resources Defense Council, Sustainable FERC Project, Fresh Energy, GridLab, American Clean Power Association and Solar Energy Industries Association — said MISO's plan to apply different accreditation methods between thermal and non-thermal generating resources is unjustified and unlawfully discriminates based on resource type.

MISO's new capacity accreditation design applies only to thermal generation; the RTO is still working on a separate accreditation for its renewable and load-modifying resources.

MISO Submits Rehearing Request for Different Reason

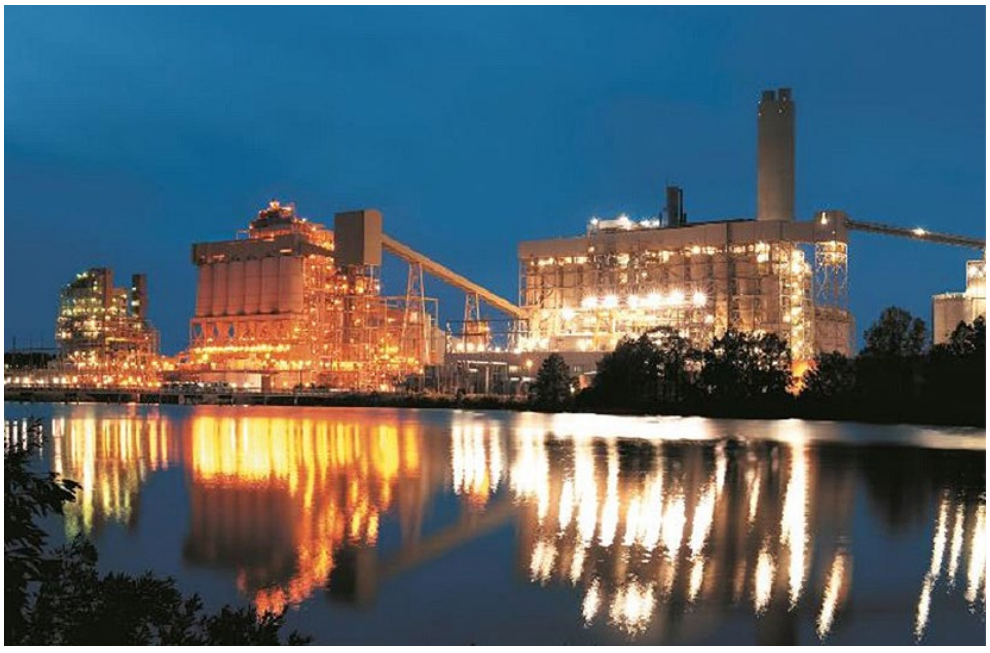
Meanwhile, MISO is asking FERC review its decision to reject the minimum capacity obligation (MCO).

The grid operator said the commission's denial "failed to recognize the proposal as a solution to encourage prudent planning by load-serving entities, utilities, suppliers and regulators to address immediate resource adequacy concerns and the widening gap between available capacity and rising demand."

MISO said the MCO is not meant to incent generation construction, as FERC assumed.

"Instead, the MCO is a solution designed to serve as a guardrail for the region's increased reliance on the PRA [Planning Resource Auction] for more than residual capacity needs," the RTO said. It added that the rule would help avoid "last-minute capacity shortfalls in the PRA by requiring a minimum level of prudent, forward planning by LSEs."

MISO said years of low capacity prices have led to expedited retirements and deferred investment in generating facilities, with some LSEs depending on its residual auction to stock all their capacity needs. ■



Madison Unit 3 at the Brame Energy Center in Louisiana | *Cleco*

MISO News

Stakeholders Endorse MISO's Final MTEP 22

$4B Package Draws More Abstentions Than Votes

By Amanda Durish Cook

MISO's final Transmission Expansion Plan for 2022 (MTEP 22), comprising 382 projects totaling $4.3 billion, earned a hesitant nod from the stakeholder-led Planning Advisory Committee last week.

Four of 11 MISO sectors voted electronically for the annual transmission expansion package while five sectors abstained, some with criticisms. None of the sectors voted to reject MTEP 22.

MISO's Transmission Owners, Municipals and Co-ops, Affiliates and Independent Power Producers sectors voted in favor of the plan. The RTO's State Regulatory, Public Consumers, Eligible End Use Customers, Transmission Developers and Environmental sectors abstained.

The Power Marketers and Coordinating sectors didn't participate. It's not unusual for the End-Use, Public Consumers, Power Marketers and State Regulatory sectors to abstain or refrain from casting ballots in PAC voting matters. It is unusual, however, for abstentions to outnumber votes in favor of MTEP package recommendations.

The Transmission Developer sector said it abstained because MISO's $3 billion spend in "other" category projects is large and the grid operator "has not adequately considered regional alternatives that may be more efficient or cost-effective solutions to the identified needs." The developers also said there's currently "minimal ability for MISO stakeholders to meaningfully participate in the planning" of projects in the "other" category.

MTEP 22 contains 69 generator interconnection projects costing $547 million; 41 baseline reliability projects at $545 million; and 270 other projects at almost $3.2 billion. The other project category includes TOs' reliability projects and work needed for load growth and to address existing facilities' age and condition. Other projects have become the lion's share of MTEP spending since the 2018 cycle.

The Environmental sector said it took exception to language in MTEP 22's report. It said MISO should clarify that the changing resource mix "is not driven solely by carbon-reduction goals" and said staff shouldn't exclusively use natural gas resources as an example of a solution for more available resources.

In the report, the grid operator says it has a responsibility to reliably transition from "today's resource mix" to "our members' stated carbon-free goals." The environmental representatives said MISO should add that the transition is also driven by "economics, state and utility policies, and consumer preferences."

The sector has previously said that MISO is inappropriately promoting natural gas generation development over other resource types as its reserve margins thin. (See *MISO Executives Spotlight Fleet Evolution Planning, Risks*.)

"If MISO refuses again to meaningfully address these concerns, then we request that the System Planning Committee of the Board of Directors require MISO to address these requests in a meaningful way prior to sending the draft MTEP 22 report to the full Board of Directors," the sector wrote.

The annual transmission package now advances to the board's System Planning Committee for consideration. The full board will then vote on MTEP 22 in early December.

Entergy Arkansas' $122 million Sandy Bayou 500/230-kV substation to accommodate load growth is this year's most expensive project. It will tap into the utility's existing Driver–Shelby 500-kV line.

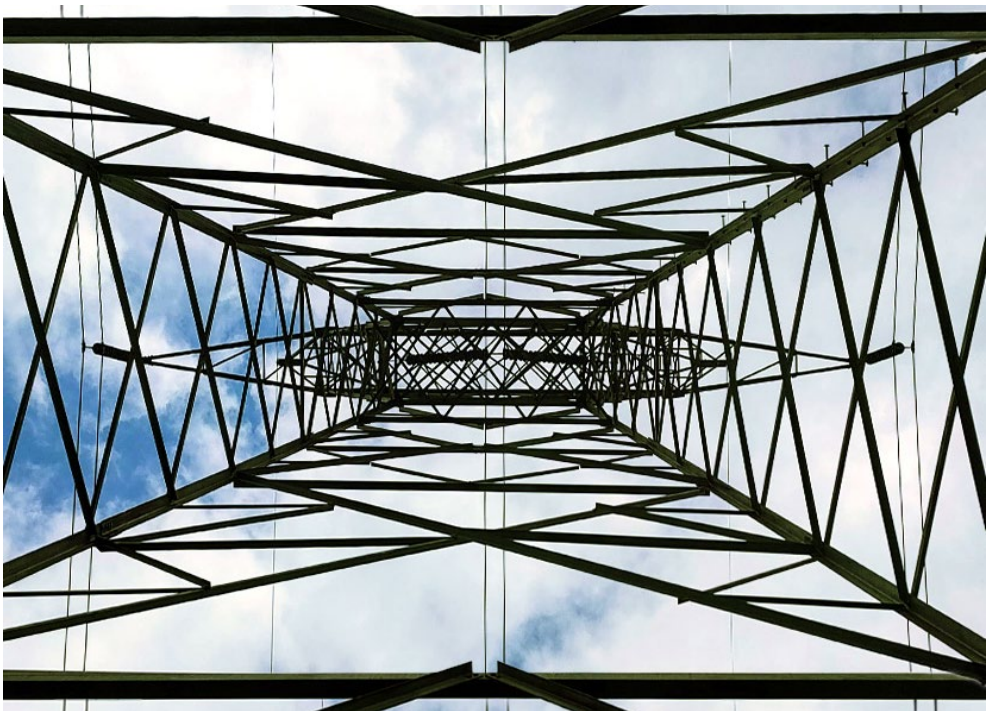
That second-most expensive project is Ameren Missouri's need for $120 million of new static synchronous compensators necessary to reinforce the system when the utility retires its 1.2-GW Rush Island coal power plant. (See *MISO's 2022 Tx Planning Cycle Exceeds $4B*.)

MISO project manager Sandy Boegeman said MTEP 22's costs are typical when compared to other recent MTEP packages. She said age and condition drove many of the reasons behind the projects.

MTEP 22 devotes $2 billion to substation work, $1.4 billion to line upgrades, $440 million to new lines, $146 million to voltage devices and $109 million to transformer projects.

The developers behind the Grain Belt Express asked that MISO incorporate its line and other "advanced stage merchant transmission" into annual transmission planning assumptions. (See *Invenergy Announces Grain Belt Express Expansion*.)

Boegeman reiterated MISO's stance that it doesn't include merchant transmission projects in modeling until the projects execute interconnection agreements with MISO or until they have been included in a relevant integrated resource plan. ■



NYISO News

NYISO Installed Capacity Working Group/Market Issues Working Group Briefs

Capacity Accreditation of 'Performance-based' Resources

RENSSELAER, N.Y. — NYISO on Sept. 30 *presented* the Installed Capacity Working Group/Market Issues Working Group with a proposed new technique for setting resource-specific derating factors for "performance-based" resources such as intermittent generation and limited control run of river.

The new technique would be used in conjunction with capacity accreditation factors (CAFs) — a measure of the marginal reliability contribution of "representative" generators for each capacity accreditation resource class (CARC), a differentiation based on technology and operating characteristics.

The CAFs, which reflect characteristics such as energy duration limitations and correlated unavailability due to weather or fuel supply limitations, will be used in conjunction with resource-specific derating factors that reflect the difference in a unit's output from the modeled profile of the CARC.

The new proposal seeks to address problems with other proposed methodologies that the ISO said can result in distorted calculations of performance-based resources' unforced capacity (UCAP).

This proposal is part of Phase 2 of the buyer-side mitigation (BSM) rules that were accepted by FERC in May. (See *FERC OKs NYISO Capacity Market Changes Stemming from NY Climate Law*.)

NYISO's proposed average capacity factor ratio approach can result in distorted winter UCAPs for resources that have smaller winter capacity factors than annual CAFs.

An alternative, the difference approach, can result in zero or negative UCAPs for resources with lower annual CAFs than average capacity factors in the winter.

To address the shortcomings of the two methodologies, the ISO proposed first calculating UCAPs for each performance-based resource under each approach and then assigning each resource the UCAP value that results in the closer alignment between the resource's effective capacity value and its annual CAF.

The ISO said its testing of the proposed methodology using historical data from capability year 2021/22 concluded that the new approach removed the distorted winter UCAP values that would result from the use of either approach alone and provides reasonable values for all examined resources.

The ISO also made a *presentation* on a consumer impact analysis it is conducting on its capacity accreditation proposal. The analysis, which will focus on the 2030 resource mix, will consider the impacts on reliability, costs, transparency and environment and new technologies.

NYISO's Tariq Niazi said the analysis will give stakeholders an idea of the "direction [and] magnitude" of the new methodology.

The ISO plans to present the results of the analysis at the ICAPWG meeting Oct. 19.

Query on Transmission Nodes & TCCs

In response to a stakeholder inquiry, NYISO *announced* it is open to considering transmission nodes as the points of injection (POI) or points of withdrawal (POW) for future transmission congestion contracts (TCC) used to hedge congestion costs.

Transmission nodes are collections of designated load buses on which individual distributed energy resources (DER) are located, mapped, and may participate together in an aggregation.

The ISO publishes a list of valid POIs/POWs before each centralized TCC auction in Attachment E of the TCC manual. For the currently ongoing auction, the ISO *lists* more than 300 approved locations. The ISO also prohibits the use of certain POI/POW groupings, as detailed in Attachment F of the TCC Manual.

The ISO said it will not allow transmission nodes to be a part of a TCC in its initial deployment of the DER participation model approved by FERC and that it is not required for compliance with Order 2222. (See *NYISO Discusses FERC Order 2222 Compliance*.)

But it said it would consider allowing nodes as the point of injection or point of withdrawal for a TCC in the future if "presented with reasonable use cases."

"The NYISO has not yet been presented with a productive use case for TCCs at transmission nodes," it said.

Questions and suggestions about the proposal can be directed to Kirk Dixon (*kdixon@nyiso.com*).

Ramp Rates for Duct-firing Generators

The ISO *proposed* to change its application of generator ramp rates (MW/min) to accommodate the 45 combined-cycle gas turbines (CCGTs) equipped with duct-firing burners, which inject additional heat to their steam cycles by burning fuel directly in the exhaust duct.

The change seeks to address a concern that the units may not be able to achieve their registered emergency response rate (ERR) when ramping through the high end of their capacity where duct burners are used. The 45 CCGTs have about 840 MW in their duct burner regions.

The ERR, which is used for scheduling of operating reserves, is a single value that must be greater than or equal to all normal response rates (NRRs).

The new proposal would create multiple ramp rates for scheduling of 10- and 30-minute spinning reserves, reflecting the lower ramp rates seen during duct firing.

Total UCAP (MWs) by Approach					
	Winter 2021 - 2022			ICAP	CAF
Resource Type	Difference	Ratio	Proposal		
Biomass	68	68	68	100	65%
LCROR	483	463	463	930	36%
Onshore Wind	88	127	127	1574	9%

Comparison of difference, ratio & NYISO's proposed UCAP methodologies | *NYISO*

NYISO News

The ISO said this would be consistent with its energy scheduling rules, which use multiple ramp rates.

Testing has been performed to verify that 10- and 30-minute spinning reserves are accurately scheduled across multiple ramp rates and that the concept does not harm scheduling of other energy or regulation units.

The ISO is targeting the end of October to present a market design concept. Prototyping of the 10- and 30-minute spinning reserves participation limit will begin later in the year.

Ramp Limits on 'Internal Controllable' Lines

The ISO *provided* a justification for its proposal to limit ramping on "internal controllable" transmission lines (ICL) such as Clean Path New York (CPNY).

CPNY, a 1,300-MW HVDC line that will run 175 miles from Delaware County to Queens, is expected to be the *first* "internal controllable line" in the New York control area.

The NYISO says HVDC lines can ramp up and down quickly with some able to reach ramp rates greater than 1,000MW per second — a far cry from the 10-20MW per minute averaged by a typical 1,000-MW generator.

Such lines can also ramp down very quickly without a change in system generation or load. Without ramping limits, the ISO says, ICL flows can shift to parallel AC lines, potentially causing voltage to drop below operating limits or flows on AC lines to exceed limits.

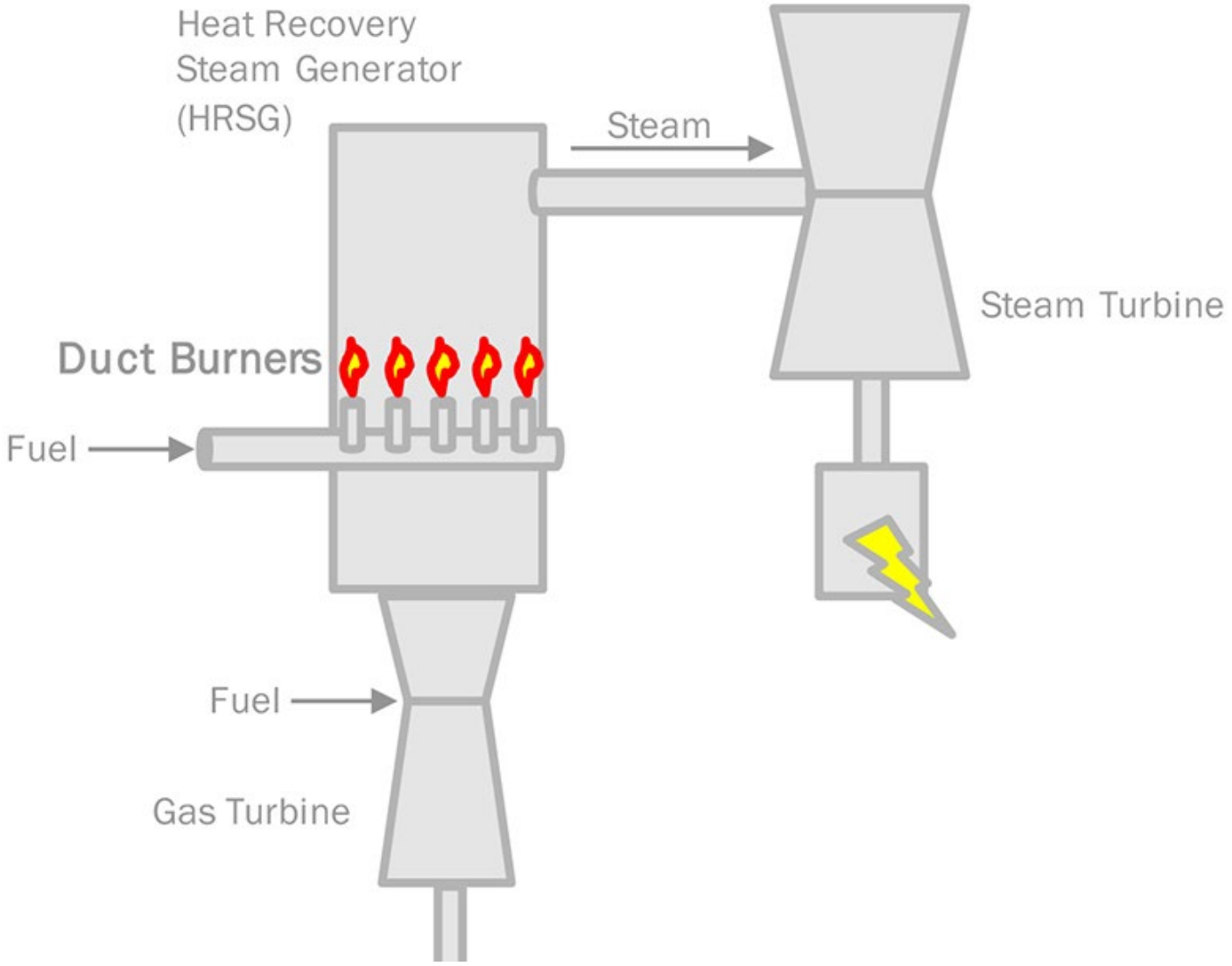
The ISO said the proposed ICL ramp limits will allow operators time to adjust generator reactive and real output, switch shunt capacitors or implement phase angle regulator tap changes to keep AC lines within limits.

The ISO noted that external AC transaction scheduling interfaces and controllable lines operate under interchange ramp limits to prevent voltage problems.

It said the approach to setting limits would be similar to its implementation of the 15-minute scheduling under its coordinated transaction scheduling (CTS) with PJM, "proposing to start with conservative limits and increase ramp as operators gain experience."

The ISO plans to discuss draft interconnection manual and deliverability tariff revisions with stakeholders through November and file tariff changes with FERC by January 2023. ■

— John Norris



Duct-firing burners via gasturbine and steam turbine | *NYISO*

NYISO News

NYSERDA Seeks 1-Year Delay for Tier 4 RECs

By John Cropley

The New York State Energy Development Authority has requested another year to set up the system of renewable energy credits that is part of the state's plan to bring clean energy into New York City.

The Public Service Commission had set an Oct. 11 deadline for the implementation plan for the Tier 4 program of the Clean Energy Standard. But in an Oct. 7 letter to the PSC, NYSERDA said Tier 4 is a complex and all-new aspect of the state's clean-energy strategy, with many requirements and many involved parties.

Because energy delivery from the two Tier 4 contracts is not expected until 2026 and 2027, NYSERDA wrote, there is time for a longer, more thoughtful process. It asked PSC to push the deadline back to Oct. 11, 2023.

Tier 4 was designed to increase use of renewable energy in New York City; while the generation mix in most of the state leans heavily toward clean power, the city itself relies almost entirely on fossil fuel-generated electricity.

The two approved Tier 4 projects — Clean Path New York and Champlain Hudson Power Express — are HVDC transmission lines that would deliver thousands of megawatts of solar, wind and hydro power to the city from Canada and upstate New York. (See *NYPSC OKs 2 Huge Clean Energy Projects for New York City*.)

Two environmental advocacy groups told *RTO Insider* on Friday that a one-year delay would not be a setback in the state's clean energy transition.

Policymakers and regulators are working to bring clean power into New York City, where the Ravenswood Generating Station is the largest power plant. | © *RTO Insider LLC*

Conor Bambrick, director of climate policy at Environmental Advocates of New York, noted that Champlain Hudson itself had pushed its target completion date back from 2025 to 2026 because of supply chain constraints and delays in the regulatory process.

Anne Reynolds, executive director of Alliance for Clean Energy New York, said the extension NYSERDA is seeking does not entail the projects themselves.

"NYSERDA apparently needs more time to iron out some complex issues with how the contracts will be managed and how the renewable energy credits from the projects will be bought and then sold, but this delay will not affect the two Tier 4 projects contracted to deliver clean power to New York City," she said via email. "This administrative delay shouldn't affect the project schedule, and the operation date for the projects is still three to five years out."

In its request for an extension, NYSERDA said development of the implementation plan depends on resolution of issues beyond its direct control. It said its staff are meeting regularly with external consultants, NYISO working groups and Tier 4 sellers' teams to develop the implementation plan. ■

NYISO News

Transmission Planning Advisory Subcommittee Briefs

By John Norris

Interconnection Base Case Rule Changes

Rensselaer, N.Y. — NYISO is proposing to broaden its rules for including projects in the base cases of transmission studies because of an increasing risk that projects studied in one process may affect those studied in others, the ISO's Thinh Nguyen told the Transmission Planning Advisory Subcommittee Oct. 3.

Because of timing issues, projects being studied in the ISO's transmission interconnection procedures (TIP) do not always meet the base case inclusion rules of the class year study, or vice versa. As a result, Nguyen said, there may be interactions among these projects that need to be studied.

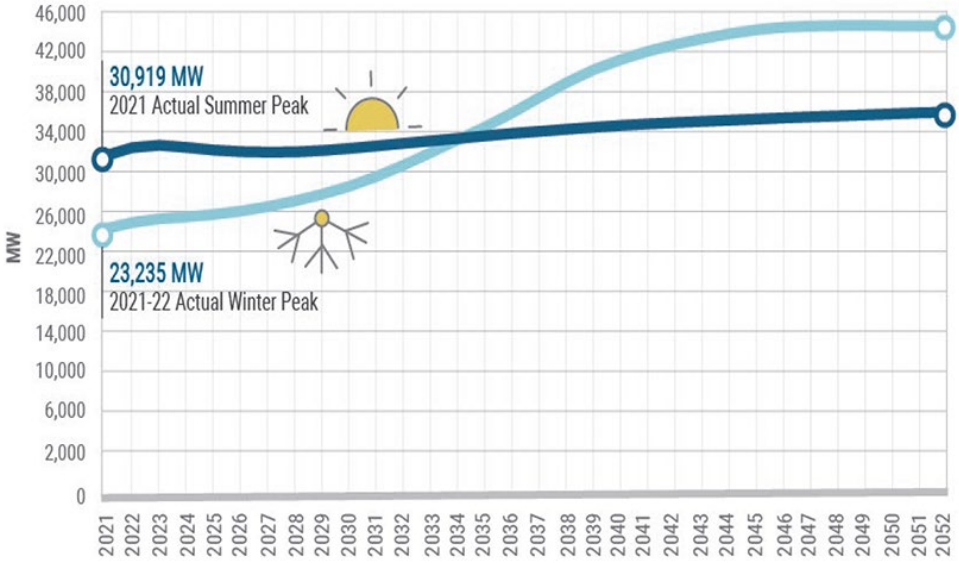
Nguyen also said the chance of this issue between studies being conducted in parallel has increased with the rise in requests entering the NYISO interconnection queue as well as the increasing number of distribution-level projects.

One proposed enhancement to the ISO's rules would revise the ISO's base case inclusion rules to specifically refer to projects being studied outside of the ISO's procedures that a transmission owner identifies as having advanced sufficiently to be considered "firm" in the TO's planning its local system.

Another change would add tariff provisions on the use of sensitivities and true-up studies in the TIP facilities studies to account for interactions with class year projects that could require the same or similar upgrade facilities. Following the completion of a class year study, the ISO will conduct a true-up to reflect class year projects accepting or rejecting their cost allocations and posting security to continue development.

Although the current tariff allows the ISO "flexibility" to account for these timing issues, the ISO said explicit tariff provisions detailing the use of sensitivities would improve coordination between the study processes.

The ISO plans to present proposed tariff revisions later this month or early in November.



The New York Control Area is expected to become a winter-peaking system in the mid-2030s as a result of electrification of space heating systems. | *NYISO*

RNA Draft Report Findings

The ISO presented findings from its fourth draft of the 2022 Reliability Needs Assessment (RNA), which did not identify any reliability needs for the 10-year study period but found that resource adequacy and transmission security margins are tightening over time.

The RNA report identified the risk that extreme weather events, such as heat waves and severe storms, could result in significant reliability deficiencies reducing the ability to serve demand, particularly in New York City.

The RNA also evaluated the impact on the system if 6,300 MW of gas-fueled generation became at risk due to fuel shortages during winter peak conditions. The RNA found that if these generators are unavailable during a peak winter in 2032, reliability would be diminished but still within the loss-of-load-expectation criterion. However, reliability would not meet statewide system margin under expected winter weather conditions by winter 2031-32, presenting a significant future risk.

The ISO told the committee it made small changes in response to stakeholder comments and questions since the second draft of the RNA was presented at the Sept. 1 TPAS meeting. (See "RNA Draft Report Finds No Immediate Needs," *NYISO Proposes Fixes for Interconnection Backlog*)

The ISO plans to bring the RNA to votes at the Operating Committee Oct. 13 and the Management Committee Oct. 26 before submitting it to the NYISO Board of Directors for final approval in November. ■

PJM News

Gov. Youngkin Releases 2022 Energy Plan

By Devin Leith-Yessian

Virginia Gov. Glenn Youngkin (R) last week released an energy plan that focuses on developing still-untested carbon-free resources while calling into question the ability of current renewable technology to make up for lost capacity as the state shifts away from fossil fuels.

In a letter announcing the plan Oct. 3, Youngkin wrote that previous plans for the transition to cleaner energy were too rigid and followed an "either/or" mindset, whereas his plan seeks a "both/and" approach of expanding solar and wind while investing in other emerging technologies.

"In fact, the only way to confidently move towards a reliable, affordable and clean energy future in Virginia is to go all-in on innovation in nuclear, carbon capture and new technology like hydrogen generation, along with building on our leadership in offshore wind and solar," he wrote.

While the plan lacks the power of law, it seeks to provide a framework for future policymaking through an assessment of the current state of the energy environment and a series of recommendations for each of its guiding principles: affordability, reliability, competition, innovation and environmental stewardship.

Some of the plan's recommendations direct state agencies to complete studies on potential reforms, such as addressing cost overruns in utility infrastructure projects, although most of the proposals would require action from the General Assembly. Democrats, who control the state Senate, are likely to oppose Youngkin's efforts to roll back the previous administration's policies.

The plan takes an especially strong stance on creating a hub of nuclear development in southwest Virginia, drawing on expertise fostered at the Norfolk Naval Base, where the nation's fleet of nuclear submarines and carriers are maintained. It calls for a collaboration with government, industry and academic partners to work toward the deployment of a commercial small modular nuclear reactor within the next 10 years.

The "all of the above" approach detailed in the plan also promotes investments in developing carbon capture, utilization and storage technologies to lower the emissions of existing fossil fuel generation and industries, while building new industries in battery production and renewable energy, particularly the $9.8 billion Coastal Virginia Offshore Wind project.

Virginia Gov. Glenn Youngkin, photographed at a Sept. 22 rally, released his 2022 Energy Plan on Oct. 3. The plan calls for making investments in future and emerging technology and reassessing existing legislation that would mandate the shutdown of fossil fuel generators. | *Shutterstock*

Proven Technology

The plan received support from a broad coalition of business associations and energy companies who said it provides for affordable power while working toward a cleaner environment.

"Affordable, reliable, sustainable and secure energy from a diversity of resources is a necessity for Virginia's economic competitiveness," Virginia Manufacturers Association CEO Brett Vassey said. "The VMA is thankful that Gov. Youngkin's energy plan recognizes that affordability and environmental responsibility are not mutually exclusive public priorities."

The plan takes aim at actions undertaken during the administration of Youngkin's Democratic predecessor, Ralph Northam, including passage of the Virginia Clean Economy Act (VCEA) of 2020 and the Clean Cars Virginia bill, which ties the state to California's requirement that only zero-emission vehicles be sold after 2035, as well as participation in the Regional Greenhouse Gas Initiative.

The governor's plan says that transitioning all new vehicle sales to EVs would eliminate consumer choice and strain the electric grid, particularly if done while the state is transforming the generation environment.

Kim Jemaine, policy director with Advanced Energy Economy, expressed surprise that Youngkin's plan called for reauthorizing the VCEA every five years, contending that the law shares many of the same goals as his energy plan and a path toward achieving those goals through technological investments while also expanding proven and developable clean energy.

"Gov. Youngkin's objectives of reliability, affordability, innovation, competition and environmental stewardship are all achievable within the framework of the VCEA. It's unfortunate that the 2022 Energy Plan spends so much time disparaging the VCEA when that law offers a clear path to achieving the administration's purported goals," Jemaine said in a statement.

Requiring the law to be reauthorized regularly would also make it more difficult for businesses to plan for the future, particularly those which have made clean energy pledges, Jemaine said.

By remaining a party to RGGI and holding onto the clean cars standards, Virginia would also provide for an energy sector that is cost-effective, reliable and focused on environmental stewardship in a manner that aligns with Youngkin's energy goals, she said.

"RGGI is helping Virginia transition towards a clean grid while strengthening our flood resilience and cutting Virginians' electric bills with energy efficiency. The Clean Cars standards help ensure Virginia is a leading state in transportation electrification, encouraging innovation, cutting tailpipe emissions, and reducing our reliance on costly, imported oil," she said.

Jemaine told *RTO Insider* that she sees some bright spots in the plan, including an emphasis on expanded offshore wind, increased competitive bidding by independent power producers and investments in future technology innovation — though she said that cannot come at the cost of also investing in proven clean energy today.

"What the energy plan does is it really emphasizes emerging technology like nuclear and hydrogen, and that's fine, because those technologies may have a space in the future … in the meantime we have to invest in technologies that we already know to ensure that the grid is more stable, reliable and cost effective," she said. ■

PJM News

Murphy Outlines NJ Building Electrification Push

FERC's Phillips Talks Transmission Planning NOPR

By Hugh R. Morley

ATLANTIC CITY, N.J. — The state has formed a multi-stakeholder task force to plan how to accelerate the effort to reduce greenhouse gas emissions from buildings, its second largest source of emissions, through electrification, Gov. Phil Murphy told hundreds of attendees at a state-organized Clean Energy Conference on Oct. 3.

The Clean Buildings Working Group — which will include union leaders, academics, experts in industry, environmental justice advocates, a builder, and private heating and energy companies — will focus on how best to implement the transition from fossil fuel heating, appliances and boilers to clean energy backed with energy efficiency strategies, state officials said.

The initiative will "help us ensure that we maximize the potential of every watt of green energy" as the state reaches for its goal of 100% clean energy by 2050, Murphy told the conference, at which more than 650 people registered to attend. The group will "focus on the job of making our current building stock more energy efficient and on ensuring that new buildings are arguably more so."

"It will require a skilled workforce to employ new green building technologies," Murphy said. "It will further require making needed health and safety repairs to low- and moderate-income housing to get them to the starting point for beneficial electrification. And it will require deploying deep federal investments in green building technologies equitably across should."

Jesse Jenkins, an assistant professor of engineering at Princeton University, who gave a keynote speech on "The Economics of Decarbonization" at the start of the second day of the conference, told the audience that while there have been a variety of strategies tried and some adopted across the nation on how to increase the use of electric vehicles or install more electric chargers, the challenge of converting buildings to clean energy is largely untouched.

"I've not seen any state yet quite crack the code on what the building standard is, what the building policy is, that every state that is interested in leading [on clean energy issues] should be following," said Jenkins, who leads the Princeton ZERO Lab. The federal government has also largely left it alone, aside from recent funding for building electrification, leaving the states to act, he said.

N.J. Gov. Phil Murphy | © *RTO Insider LLC*

"The state that cracks the code will see that replicated," he said.

Tackling Building Emissions

Murphy's working group initiative comes after the state has taken some strides in addressing building emissions but not with the same vigor as it has put into some other clean energy sectors, such as offshore wind and stimulating the uptake of electric vehicles and installation of electric chargers.

The New Jersey Board of Public Utilities (BPU) on Sept. 7 approved a program that will require 30,000 buildings of more than 25,000 square feet to annually report their water, gas and electricity use in an effort to stimulate conservation and cut energy use. (See *NJ BPU Backs Utility Benchmarking for 30,000 Buildings*.)

In addition, the New Jersey Department of Environmental Protection (DEP) has posted new rules on the *New Jersey Register* that would prevent it from issuing permits for new fossil fuel-fired boilers of 1 to 5 MMBtu unless it is "technically infeasible" to use a non-fossil fuel boiler. The rules could be enacted Dec. 6 if no major changes are made.

The introduction of the rules showed the sensitivity of some stakeholders to building electrification, with a coalition of 24 New Jersey business and union interests — among them some of the state's largest business groups — lobbying to halt the state plan. The group says 5,500 buildings around the state would come under the boiler rules. (See *Business Groups Try to Head off NJ Building Electrification Rules*.)

The governor formed the working group in part because of the complicated nature of the task of electrifying buildings that are old and need extensive renovation, said Jane Cohen, executive director of the governor's Office of Climate Action and the Green Economy.

"A lot of our housing and commercial buildings really need some significant health and safety and other types of repairs to get to the starting line to be able to partake in beneficial electrification," said Catherine Klinger, a senior policy adviser to Murphy who will head the working group.

"Buildings are just more complicated than EVs and other types of green technology, because there are so many different types of buildings, so many different use cases," she said. "There's lots of legacy systems; you're talking every-

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thing from delivered fuel and propane to old boilers and large multifamily and commercial buildings. So, there's lots of different kinds of technologies that need to be employed, skillsets that you need in the workforce and strategies to decarbonize those different types of buildings."

In addition, the state wants to ensure that low- to moderate-income residents and environmental justice communities get high priority in the allocation of resources for electrification, she said. The issue will be addressed in a similar way to the BPU's recent Whole House pilot program, she said. The program, announced on Sept. 26, seeks to remediate health and safety hazards — such as electrical deficiencies and lead-based paint — in participant houses in coordination with the implementation of energy-efficiency measures.

Klinger said that through meetings and input from members, the group will be "looking at legislative levers, policy levers, funding incentives, and then out of those insights, our office will develop a roadmap to building decarbonization."

Promoting Equity, and Transmission

FERC Commissioner Willie Phillips | © *RTO Insider LLC*

Speaking after Murphy at the conference, FERC Commissioner Willie Phillips cited the Whole House program as one that other states can follow.

The program "is a beautiful combination of energy efficiency and equity," he said, adding that "it recognizes that before any customer can take advantage of the clean energy transition, you have to make sure" that you take care of the fundamentals of their housing.

To embark on the clean energy transition, he said, "we have to acknowledge that equity must come first," as New Jersey has done.

Phillips said that as a former president of the Mid-Atlantic Conference of Regulatory Utility Commissioners, he believes that "New Jersey has laid out a blueprint that many other states can follow" in a variety of issues, among them solar energy and offshore wind.

Phillips also took the opportunity to push for New Jersey and other states to take a long view of upgrading the grid. FERC in April proposed rules (RM21-17) that would direct transmission providers to revise their planning processes to, among many other things, identify infrastructure needs on a long-term, forward-looking basis and propose a list of benefits on which they would base their selections of proposed projects to meet those needs. (See *FERC Issues 1st Proposal out of Transmission Proceeding*.)

"If we don't plan long-term, it's going to hurt each and every one of you in your pocket because you are going to build out a dumb system for a smart future," he said. Such a result would end up being expensive and is "going to hurt each and every person in this room."

"It is no secret that our transmission needs have increased over the years," he said, citing driving factors such as resource retirements, electrification of transportation and buildings and clean energy policies. "If we cannot do this affordably, we will not do it successfully," he said, adding that further costs can be saved if "we squeeze as much capacity as we can out of the current system."

"We are not requiring planners to elevate one particular policy over another. But what we are doing is saying, 'This is the reality. This is what is happening. And it makes sense for us to consider these in our planning before they come up as a problem on our system,'" he said. "I am also proud to say that the proposed rule elevates the role of states regarding transmission buildout and cost allocation."

Such a planning process would also help avoid "problems, and litigation and delays on the back end so that we can actually get some of this needed transmission built in an efficient manner.

Asked after the speech what are the biggest issues facing the grid, he cited "interconnection reform."

"We have so many of our projects entering the interconnection queue, [and] we know that only 20% of those are going to be interconnected ultimately," he said. "We have to figure out a way to undo that bottleneck to make sure that those projects can go ahead."

He said the solution would be to go from a "serial, first-come, first-served process, to a clustered approach where it's first-ready, first-served. The problem with the other 80% is they are caught in a situation that is "almost like a game," he said.

"You know you are going to have to have for some projects very costly upgrades to the system. So, you see that those upgrades are needed and then you withdraw the project," he said. "Then the person who finally gets lucky and gets in, they have to shoulder the cost of that upgrade and everybody else gets a free ride. That is what we are trying to solve." ■

PJM News

States Face Challenge Tying Storage Incentives to Emissions Reduction

NJ Storage Proposal Offers Pay-for-performance Incentives

By Hugh R. Morley

ATLANTIC CITY, N.J. — Spurred by the rapid rise in renewable energy project planning and declining battery costs, storage development is growing nationwide, but states need to ensure that they fund, shape and incentivize projects that contribute to their emission-reduction goals, a speaker told New Jersey's Clean Energy Conference on Oct. 4.

States such as New Jersey, which is in the process of planning its first large-scale electricity storage incentive program, need to focus not only on stimulating storage capacity development but on making sure that the resulting projects help cut the use of fossil fuel generating plans, Todd Olinsky-Paul, of the Clean Energy States Alliance, said on a panel at the conference, organized by the New Jersey Board of Public Utilities (BPU).

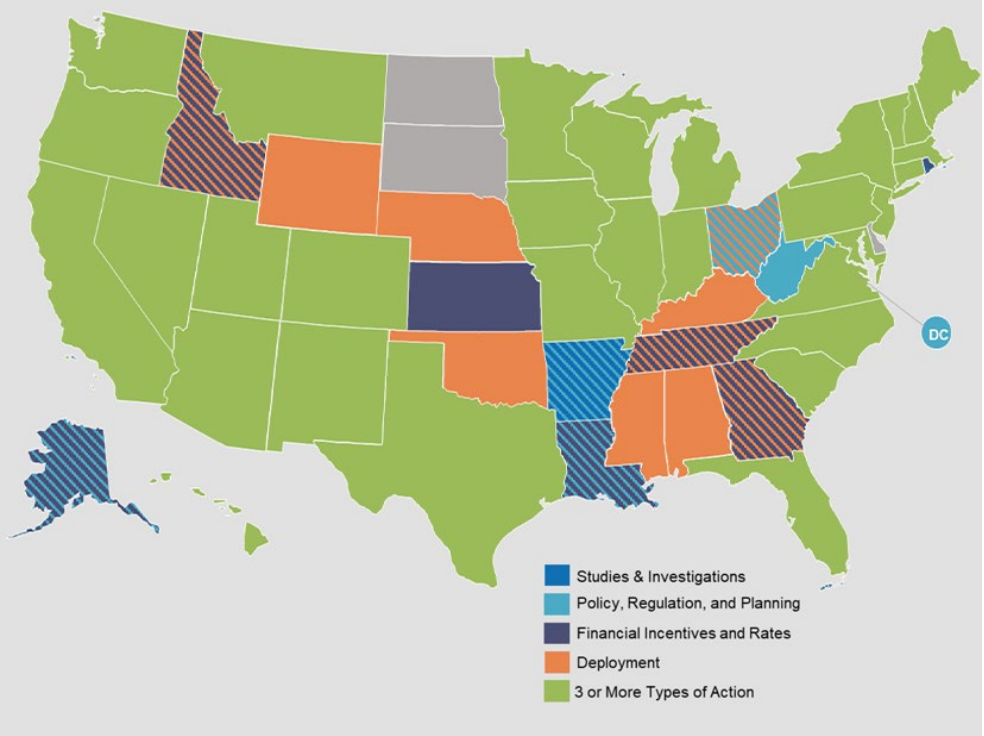
The goal is "not just to get the storage there; it's to get it there and link it to whatever policy targets or aspirations the state has," Olinsky-Paul said. Projects need to charge up their batteries with cheaper, off-peak power and be ready and available to discharge when demand is greatest, to help negate the need for utilities to fire up fossil-fueled peaker plants, he said.

His comments came amid what he said is a dramatic increase in storage development in almost all states. Ten years ago, he said, he could have summed up national storage development activity by citing a handful of programs. "But things have exploded so much in policy in the last few years that I can no longer do that," he said.

The rapid advance of the sector prompted another panelist, Brian Kauffman of Enel North America, to advise states looking to jumpstart or boost their storage capacity that they no longer need to think of developing a pilot program first.

"There's a lot of examples of how to structure them and what results in customer uptake. There's a very mature ecosystem of competitive purchase market participants," Kauffman said.

"A lot of times, these pilot programs are set up where you don't really know what the cost of doing the project is going to be [or] who's going to participate in the project; you just want to learn," he said. But now, "you have thousands of customers who are participating in programs across a dozen states or so."



More than two dozens states have now taken three actions or more to develop storage capacity, including studies and investigations, introducing new policies and regulations and deploying storage projects. | *NC Clean Energy Technology Center*

Finding the Right Incentive Level

Storage is widely seen as a paramount element needed to manage electricity supply as intermittent renewables become increasingly dominant.

The conference came just after New Jersey, admitting that it had lagged state ambitions in developing storage capacity, released a straw proposal on Sept. 27 that outlined a plan to stimulate the development of standalone storage capacity by offering incentives for grid-scale and consumer-level projects. (See *NJ Offers Plan to Boost Lagging Storage Capacity*.)

The BPU's plan, known as the *Storage Incentive Program (SIP)*, would provide incentives for both utility-scale and distributed projects. About 30% of the incentives would be paid to storage projects as fixed annual incentives, with a set value per kilowatt-hour of capacity. The remainder of the incentives would be paid through a "pay for performance" mechanism and tied to the environmental benefits.

Jim Ferris, deputy director division of clean energy at the BPU, told the conference that the fixed incentives would be awarded using a "declining block structure" that has worked in other states. The program would set capacity blocks at a certain incentive, and once the BPU has allocated a block of incentives to storage projects, a new block would open at a lower rate.

"In that way we are providing certainty to the market, but also finding the right incentive level," Ferris said. "Obviously, if a particular block does not fill at that incentive level, we will have the opportunity to either extend that particular block and incentive or even go back and increase the incentive."

The agency also has sought to ensure that it does not provide financial support for a project that "just sits unused," he said. To receive the incentive, "the device will need to be available for 95% of hours," he said.

The pay-for-performance incentive, which is based on PJM marginal carbon intensity data, is designed to tie the BPU's incentive to demonstrable emissions reductions, Ferris said.

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"So we would be incentivizing when storage is charged when emissions are low, and discharged when emissions are high. And that delta will yield an incentive," he said. The performance incentive for distributed projects is based when the project injects energy into the system or is used to reduce the use of energy at the request of electric distribution companies, a strategy used in programs in Connecticut and Massachusetts, he said.

Monetizing Storage

States have taken different approaches in seeking to stimulate storage development, CESA's Olinsky-Paul said. They include mandating a certain amount of storage by a particular date, or just setting a target capacity procurement, he said. Nine states have set a target. Among them are California, shooting for 1,825 MW by 2020; Massachusetts, with 1,000 MWh by 2025; New York, with 3,000 MW by 2030; and Oregon, 5 MWh by 2020.

He displayed a slide that showed more than two dozen states have taken three or more types of action to plan for storage development, including studies and investigations, new policies and regulations, and financial incentives and rates. And all but three states have taken at least one step toward storage development.

One difficulty in stimulating storage development, according to the BPU and panelists at the conference, is that storage devices are difficult to "monetize," which in turn puts the onus on state support. For that reason, the BPU proposal encourages investors in storage projects to pursue "value stacking," or looking for several revenue streams to support the project.

While storage projects can provide benefits such as reduced electricity costs and emissions, "the current revenue streams, as in a lot of places in the U.S., including New Jersey, really aren't sufficient now for storage to scale," Enel's Kauffman said.

Olinsky-Paul said one of the "best practices" that states should follow is identifying the attributes of a project that are "priced" or monetizable. He cited the example of a service station owner who installs a storage project on the property.

"So when the grid goes down, I'm able to fuel customers' cars, first responder vehicles; that's providing value to the community," he said. "Did I get paid for it? No. Because there is no market for resilience. I can't bid that service into a market or sell that service to utility as a backup power service."

So the state needs to look at the balance of monetizable and non-monetizable benefits and work out "how are we going to provide that gap funding somehow to encourage that market to develop," he said.

For the operator, the monetary benefits depends on the business model that the storage operators develops, Olinsky-Paul said. For example, the operator may use an arbitrage model of charging up the storage at night when the power price is low and selling the energy at peak hours when the price is higher, he said.

The operator of a solar farm may find storage provides "capacity value," which in turn provides a financial revenue, he said.

"Solar by itself doesn't have a lot of capacity value, because it doesn't have an on-off switch; you can't rely on it," he said. "So you've now firmed the solar power that was previously variable. Well, there's a value to that. If you're bidding that power into a wholesale market, and they want firm power, they're going to pay more for it if they know that you can turn it on and off than if you are just at the mercy of the clouds." ■

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PJM PC/TEAC Briefs

Planning Committee

Stakeholders Endorse 2022 Reserve Requirement Study Results

The PJM Planning Committee on Oct. 4 voted by acclamation to endorse the results of the 2022 Reserve Requirement *Study*, which would reset the forecast pool requirement (FPR) and installed reserve margin (IRM) for the next three years and determines a recommendation for 2026/27. It would also set a winter weekly reserve target (WWRT) for the upcoming season.

The recommended IRM remains at its current 14.9% for 2023/24 before falling to 14.8% the following year and declining to 14.7% for 2025/26 and the next year. Last year's study recommended a similar decline, though moved up a year in advance. (See "Reserve Requirement Study Recommends Raising IRM and FPR," *PJM MRC/MC Briefs: Sept. 21, 2022*.)

Driven largely by scarce projected capacity available for import during peak season, the recommended FPR for 2023/24 increases under the study, going from 1.0901 in last year's analysis to 1.093 in this year's. That moves downward to 1.0926 in 2024/25 and falls to 1.0918 for the following two years.

The study recommends a 27% WWRT during the peak winter month of January, 23% for February — the next highest consumption winter month — and 21% in December. The figure is used to aid PJM in planning outages.

The IRM and FPR are set to be reviewed by the Markets and Reliability and Members committees in October through November and by the Board of Managers in December. The WWRT is scheduled to be voted on by the Operating Committee in November.

Load Forecast Model Recommendations Discussed

PJM Senior Analyst Andrew Gledhill reviewed the recommendations under consideration for the development of a new load forecast model.

The recommendations are derived from a *report* produced by the consulting firm Itron, which was contracted in April to perform a model review. They include:

- replacing annual/quarterly end-use indices with the use of monthly/daily indices, which would allow for the use of more recent data that are more representative of current patterns. Monthly models would also result in heating and cooling figures that are more reflective of the amount of weather variation in each month.
- continuing with the current weather simulation approach, but with a shorter historical lookback period of 20 years and seven rotations; 27 years and 13 rotations are currently used.
- replacing daily models with hourly load models, which would allow for more flexibility to incorporate future trends and technology, particularly the impact of solar and electric vehicles.
- adjusting loads for new technologies through the simulation process, reflecting current knowledge about how behind-the-meter solar and EVs behave and layering those understandings into simulations.
- incorporating climate change into long-term forecasts and evaluating long-term temperature trends for each planning zone.

Gledhill said PJM is in the process of evalu-

2022 RRS Study results:

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR*
2022	2023 / 2024	14.87%	**14.9%**	4.87%	**1.0930**
2022	2024 / 2025	14.75%	**14.8%**	4.83%	**1.0926**
2022	2025 / 2026	14.72%	**14.7%**	4.81%	**1.0918**
2022	2026 / 2027	14.70%	**14.7%**	4.81%	**1.0918**

2021 RRS Study results:

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR*
2021	2022 / 2023	14.93%	**14.9%**	5.08%	**1.0906**
2021	2023 / 2024	14.76%	**14.8%**	5.04%	**1.0901**
2021	2024 / 2025	14.68%	**14.7%**	5.02%	**1.0894**
2021	2025 / 2026	14.66%	**14.7%**	5.02%	**1.0894**

*** FPR = (1 + IRM)*(1 - Average EFORd)**

PJM's 2022 Reserve Requirement Study results | *PJM*

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ating the first four recommendations for the 2023 load forecast and will report its progress to the Load Analysis Subcommittee. The fifth recommendation is expected to take additional thought and engagement with stakeholders, with a tentative plan to incorporate it into the 2024 load forecast.

Poll Opened to Gather Support for Packages on CIR for ELCC Resources

The PC is holding a nonbinding poll to gauge support for the six proposals currently on the table to address capacity interconnection rights (CIRs) for effective load-carrying capability (ELCC) resources. Opened after the committee's meeting, the online poll closes Tuesday at noon.

The poll asks respondents to say whether they can support each of the packages and, if not, to indicate which of the design components they are against. The packages are composed of five overall components: CIR request policy; CIR verification, testing and retention policy; CIRs in ELCC methodology and accredited unforced capacity calculations; implantation and effective dates; and transition mechanisms.

The sponsors of the packages outlined the changes that the proposals have undergone over the past few months and discussed the effects each would have.

Tom Hoatson, director of Mid-Atlantic policy for LS Power, said his company's package could continue to change depending on the results of the poll, particularly its CIR request policy, which he said was written to achieve a consensus in prior special sessions and relies upon the same language as one of the PJM packages. Stakeholders questioned what the impact would be should a generator request a higher CIR level than it can deliver under that language.

Responding to questions about the impact of the packages on the cost and timing of the RTO's interconnection queue restructuring effort, PJM's Jonathan Kern said the proposals that incorporate higher CIRs into the mix would have an impact on the queue.

Economist Roy Shanker said that any time the order of the queue is changed and applications are moved ahead of each other, the cost allocation changes alongside it, and those who are "jumped over" will face increased costs. The current structure being considered would result in approximately 7,200 to 7,300 MW of projects being given priority status, which would result in an estimated $2 billion cost for applicants in the fast track and Transition Cycle 1, he said. The costs remain unknown for those in Transition Cycle 2, but Shanker said they could potentially face billions in increased costs.

"As long as you don't change that order, you don't change that cost," he said.

Transmission Expansion Advisory Committee

$13M in Tx Projects Discussed

At the Transmission Expansion Advisory Committee meeting that followed the PC's meeting, several transmission owners presented supplemental projects for the PJM Regional Transmission Expansion Plan.

Baltimore Gas and Electric is planning the *replacement* of its High Ridge 230-1 transformer, installed in 1960 and in deteriorating condition, at a $7.4 million cost.

American Electric Power meanwhile has several facilities operating on a former practice of applying a double multiplier in the ratings of facilities that connect in a configuration where flow could split between two paths in a station. The company is in the process of applying single-multiplier ratings to all its facilities, but four were flagged in PJM's 2025 RTEP analysis that could result in violations of NERC reliability standards.

The work would include replacing breakers and associated equipment at the 765/345-kV Marysville transformer, 345/138-kV East Lima transformer, 345-kV Jefferson-Clifty Creek line and 138-kV Olive-New Carlisle line at a $5.92 million cost. ■

— Devin Leith-Yessian

PJM News

PJM Operating Committee Briefs

OC Endorses Renewable Dispatch Effort

The Operating Committee endorsed a revised package of changes addressing renewable dispatch after the proposal had been sent back to the subcommittee level for additional fine tuning last month. The joint Independent Market Monitor/PJM proposal would require intermittent resources with capacity commitments to offer economic maximum megawatts equal to or greater than their hourly forecast.

Stakeholders speaking at the Sept. 8 OC meeting worried that the original language could result in renewable output being held back by use of an under-forecasted value and opted to send the proposal back to the DER and Inverter-Based Resources Subcommittee rather than vote on it. (See "Renewable Dispatch Proposal Vote Delayed," *PJM Operating Committee Briefs: Sept. 8, 2022*.)

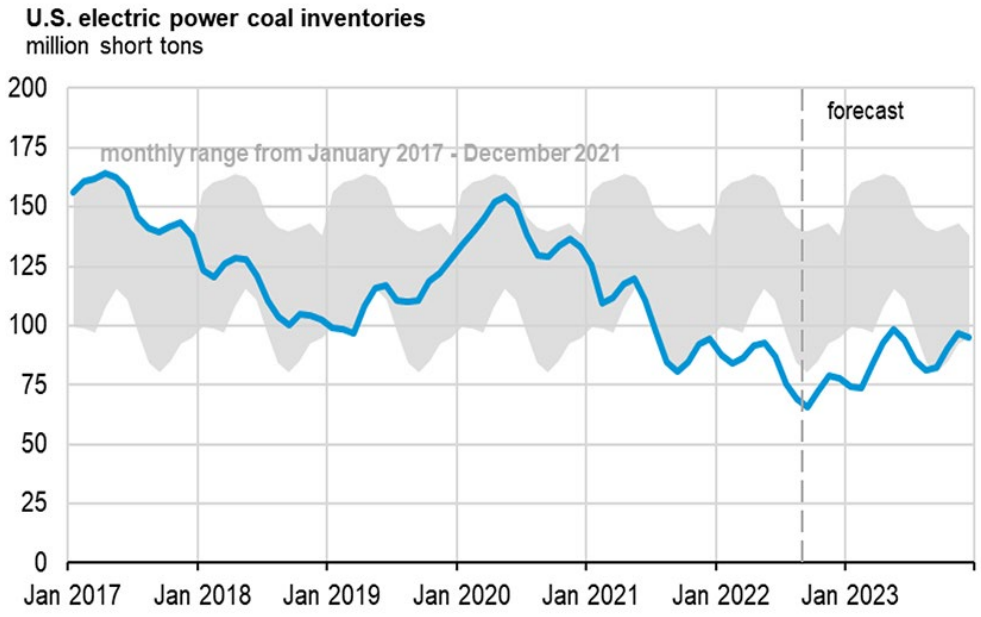
Some stakeholders were concerned about the proposal's elimination of the curtailment flag, which PJM uses to notify generation operators that their units have been curtailed and that they should adjust their output accordingly. Friday's presentation said the intent is to have generators following economic base points, rather than curtailments, which can be inadvertently prompted because of bid-in parameters or offers.

"I think we were able to work through those concerns," PJM's Michael Zhang said.

Cold Weather Preparations Begin

PJM is beginning to implement annual cold weather preparations, with data reporting for generating unit reactive capability verification underway from Oct. 1-31 and reporting for the seasonal fuel inventory and emissions data request beginning Oct. 17 and remaining open through Nov. 21. The cold weather preparation guideline and checklist will also be open Nov. 1 through Dec. 15.

The RTO is no longer facilitating a formal cold weather exercise and is asking generators to self-schedule their own testing in December on a day when temperatures are forecast to be below 35 degrees F.

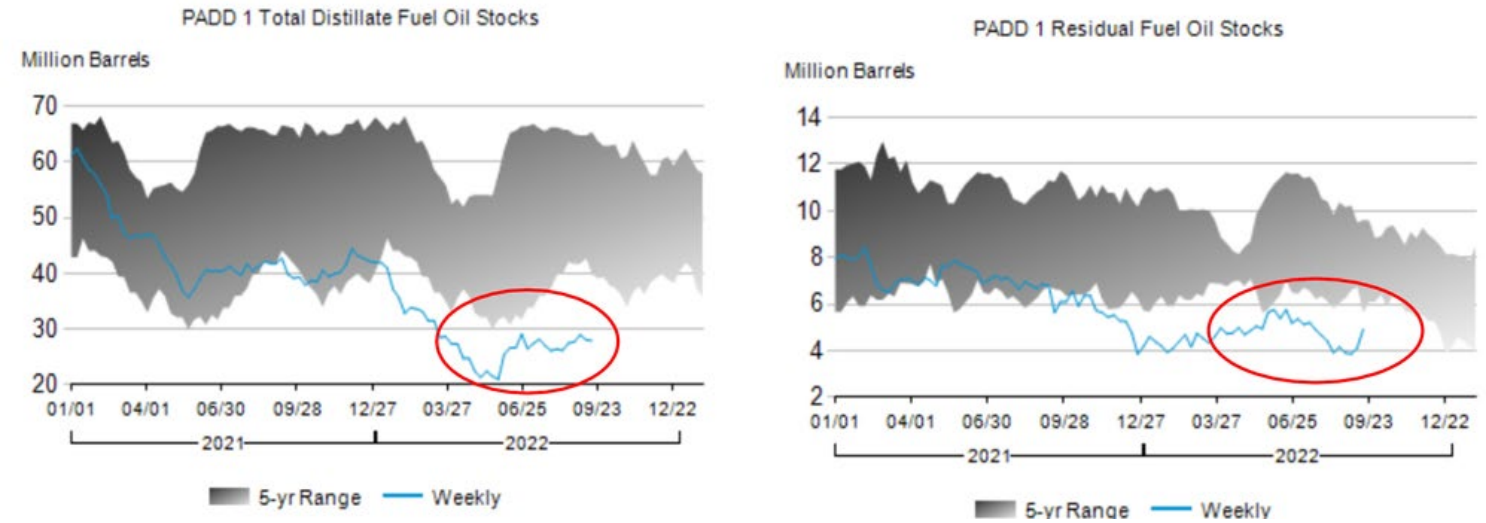


The inventory of coal available for energy generation is below both forecast levels and historical trends. | *EIA*

Fuel Inventories Remain Low, Expected to Increase Going into Winter

Fuel production rates are up across most resource types, but inventory stocks remain low as volatility and prices remain high, according to the fuel supply overview presented to the OC. (See *NERC Warns of Fuel Shortages Going into Winter*.)

Distillate and residual fuel inventories remain about 9% below their five-year averages on the East Coast, PJM Principal Fuel Supply Strategist Brian Fitzpatrick said, while reces-



Oil inventories remain below their 5-year average as economic concerns continue to outweigh high production. | *PJM*

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sion fears and a strong dollar continue to keep prices high.

Progress on contract negotiations for rail workers has alleviated concerns about a strike; however, not all unions have signed onto the agreement, and it's believed that the process could continue through the Nov. 20 ratification deadline.

Production of both oil and coal fuels remain above average, and Fitzpatrick said inventories are expected to rise over the coming months as generators stock up for the winter season.

"So far, based on the response we've seen, no significant concerns have arisen," Fitzpatrick said. "There have been signs of improvement recently with inventory build."

Revisions to Fuel Requirements for Black Start Resources Presented

PJM's Thomas Hauske went over the clarifications and revisions made to the proposed solution addressing fuel requirements for black start resources, which was endorsed by the Operating and Market Implementation committees last month. The Markets and Reliability Committee is scheduled to vote on the revised proposal during its Oct. 24 meeting. (See *PJM, Monitor Debate Black Start Fuel Requirements Proposals*.)

A provision allowing intermittent generators to contribute black start capacity as long as they are capable of providing 16 hours of full load operation with 90% confidence was clarified to ensure that it is only applicable for renewables. PJM also clarified that if a unit has its installed capacity increased because of a capital recovery upgrade, its black start revenues will be reduced commensurate with the increased capacity revenues received from the upgrade — preventing the generator from being paid twice for that added capacity.

Generators that store fuel onsite and are connected to two or more interstate pipelines will not be penalized if their fuel inventory falls below the 16-hour supply requirement if they can instead operate on fuel from the pipelines in the event of a black start.

Other OC Discussions

- The OC reviewed the recommended winter weekly reserve target from the 2022 reserve requirement, with a vote expected at the next meeting. This year's recommendations are largely lower than last year's study results, with 21% for December, 27% for January and 23% for February.
- The implementation of PPL's dynamic line rating initiative is now live, after being delayed from the anticipated go-live date on Sept. 28. The program is now active following an Oct. 6 launch. PPL had already delayed an expected July launch until September because of additional work needed for changes to its energy management system by its vendor. (See "PPL Delays DLR Implementation to September," *PJM Operating Committee Briefs: July 14, 2022*.) ■

— Devin Leith-Yessian

PJM News

PJM Market Implementation Committee Briefs

Stakeholders Endorse Prohibiting Gas Infrastructure Participation in DR

VALLEY FORGE, Pa. — The Market Implementation Committee endorsed a PJM *effort* to prohibit critical gas infrastructure from participating in demand response programs that could jeopardize the reliability of gas-fired generators. The endorsed language revises sections of manuals 11 and 18 to add language excluding "critical gas infrastructure" from being eligible as price responsive demand programs.

The changes are being considered as NERC and FERC work on their own efforts to address concerns raised by the impact of February 2021's winter storm — that a spike in load could lead to gas infrastructure being curtailed and causing a cascading failure as downstream gas generators have their fuel interrupted. The PJM language would stand until the federal regulatory bodies finalize their own standards. (See "Critical Gas Infrastructure Approved," *PJM MIC Briefs: March 9, 2022*.)

Much of the lengthy discussion on the topic focused on how PJM is considering defining critical gas infrastructure in its tariff: "as electric loads, which if curtailed, will significantly impact the delivery of natural gas to bulk-power system natural gas-fired generation." The tariff language is not part of the package endorsed Thursday and is still being fine-tuned by PJM staff with input from Thursday's meeting.

At issue was the definition of "significant impact." Calpine's David "Scarp" Scarpignato questioned how PJM would classify a curtailment causing a drop in pipeline pressure causing a downstream gas plant to run at less than full capacity, or a curtailment that doesn't cause a direct drop in a plant's ability to generate but has that effect when combined with other contingencies.

"A significant impact is a difficult measure. That's going to be difficult to implement those rules. … I wonder if we can substitute 'direct' for 'significant,'" he said.

Joe Bowring, PJM's independent market monitor, said he believes the language is "fuzzy" and therefore not enforceable. He also questioned whether there's a risk of gas infrastructure being enrolled in DR programs this winter (2022/23) as PJM considers the revisions, which will not be applied until the winter of 2023/24. Bowring also questioned why PJM has not done its own assessment of the facilities rather than relying on the sellers of demand response for the information.

Skyler Marzewski, senior. market design specialist with PJM, speaks about the first four-year review of the default cost of new entry and avoidable cost rate during the Market Implementation Committee meeting Oct. 6. | *© RTO Insider LLC*

PJM's Peter Langbein said curtailment service providers have told staff that there are not currently any gas infrastructure facilities enrolled in their programs that would meet the general definition under consideration.

Paul Sotkiewicz, of E-Cubed Policy Associates representing J Power USA, said he'd prefer to see an explicit prohibition against electric-driven gas compression stations participating in DR in any form.

"We're setting ourselves up for a cascading failure without addressing compression," he said.

Elimination of 'CT Rule' Receives Endorsement

Stakeholders also endorsed *manual revisions* being sought by PJM to eliminate the "CT Rule," which grants combustion turbines an exception from rules requiring that generators follow dispatch signals. Currently CTs can recover the costs of their full generation regardless of their load signal, while other generators receive the lesser of their actual generator or their dispatch.

PJM's Lisa Morelli, director of market settlements initiatives, said the rule is a holdover from when CTs put out a fairly constant rate of power. Now that they have a wider dispatchable range, it makes sense to require them to conform to dispatch, she said. The elimination of the exception can be made by removing a single line in Manual 28.

"CTs will now be treated as all other resources in balancing of operating reserve credits," she said.

During the Sept. 21 Markets and Reliability Committee meeting, Morelli said simulations show that uplift payments to CTs were about $1.3 million lower when recalculated without the exception over the eight highest CT uplift days in summer 2021, a 10% drop. (See: "PJM Staff Seek Removal of CT Exception on Load Signaling," *PJM MRC/MC Briefs: Sept. 21, 2022*.)

Impact of State and Local Regulations on Net CONE Discussed

PJM staff provided a first read on an *issue charge* and *problem statement* exploring how local considerations, such as state and local regulations,

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might affect the development of the net cost of new entry (CONE). The topic will return to the MIC for possible endorsement at its next meeting.

James Wilson, a consultant to state consumer advocates, recommended broadening the issue charge and potential solutions to include other possible changes beyond net CONE, such as to the shape of the variable resource requirement curve.

Gary Helm of PJM said the RTO's intent was to stick with addressing CONE and net CONE, as opposed to weighing the outcomes.

Four-year Review of Default CONE and ACR Underway

PJM's Skyler Marzewski and consultants from The Brattle Group presented an overview of the first four-year review of the *default CONE* and *avoidable cost rates* and the timeline for drafting the new values.

PJM's tariff requires the RTO to update default gross CONE and default gross ACR values for minimum offer price rule purposes every four delivery years beginning with 2022/23.

The methodology would use public national sources for the installed capital costs and fixed operating and maintenance costs, as well as using the same financial assumptions as in the quadrennial review.

"It will be a very similar process to what we did last time," Marzewski said.

Stakeholders questioned if there's sufficient geographic variability to justify using data specific to the PJM region, instead of national data. Marzewski said this was explored; however, it was found that there's limited local data available. The largest variations in the cost of development tend to be the size and configuration of generators, according to Brattle's presentation.

Default values for offshore wind were not explored in the analysis thus far as the focus was on existing generation. Instead, unit-specific analysis would be undertaken for OSW, as well as other generators with highly variable costs.

PJM Reviews Proposed VOM Language

PJM staff reviewed a set of *proposed manual revisions* that would codify a PJM package creating standardized variable operating and maintenance costs. The RTO's package was the preferred solution coming out of the MIC's Sept. 7 meeting, receiving more than 70% support over a competing package from Constellation Energy, which received 54%. (See "Two Alternatives on VOM Advance to MRC," *PJM Market Implementation Committee Briefs: Sept. 7, 2022*.)

Constellation's Jason Barker questioned PJM's classification of nuclear major maintenance costs as variable costs that are directly related to electric production based on starts and run hours and thus must be reflected in a unit cost-based offer, rather than in a capacity market offer. Barker said there is an apparent contradiction in PJM's proposed Operating Agreement and manual provisions that define nuclear refueling and other major maintenance projects as "variable" while also excluding time-based or preventative maintenance from classification as a variable cost. Barker said that Constellation and other nuclear operators consider costs incurred during planned nuclear outages as "fixed" costs. He also highlighted that all nuclear planned outages are scheduled years in advances, suggesting that projects undertaken during those outages are time-based. The company's package would exclude nuclear planned outage costs from PJM's definition of major maintenance.

The manual changes will go to the MRC on Oct. 24 for a first read with a vote anticipated on Nov. 16.

Other MIC Topics

- A first read was *presented* on a proposal to merge the DER & Inverter-Based Resources Subcommittee and Demand Response Subcommittee into a new subcommittee, given the similarity of the subjects they cover and the composition of their stakeholder participation. PJM staff said doing so would simplify scheduling internally and for stakeholders, although there were some concerns that doing so could conflate their charges and the issues they aim to address.
- PJM's Andrew Levitt gave a *first read* of a proposal to expand the RTO's current hybrid resource provisions to include installations with multiple types of generation paired with storage. The current hybrid definition allows for only one type of generation, for example solar paired with storage, while the Hybrid Resources Phase II solution would allow for "any number of different types of [generation]." The proposal would also create a detailed energy market model for inverter-based resources paired with storage, such as wind and solar combinations.
- PJM provided an *explanation* on the impact of negative day-ahead and real-time LMPs in the calculation of the balancing operating reserve credits. Negative DA or RT LMPs can result in unnecessary BOR credits caused by the treatment of day-ahead or balancing revenues, the RTO says. PJM plans to present potential solutions during future special sessions. ■

SPP News

SPP Adds SaskPower as First International Member

SPP has added its first international member in Saskatchewan Power Corporation (SaskPower), seven years after the RTO's first international transactions with the Canadian utility.

The two organizations said SaskPower's membership represents their continued efforts to increase reliability through interregional coordination. In August, they announced a 20-year interconnection agreement to expand transmission capacity between Saskatchewan and the U.S. The announcement requires construction of a new line, which will allow for 650 MW of cross-border flows beginning in 2027. (See "RTO, SaskPower Agree to Expand Interconnection's Capacity," *SPP Briefs: Week of Aug. 8, 2022*.)

"SPP is very pleased to welcome SaskPower into our organization The continued success of our organization and the integrity of the bulk power system both rely on strong interregional ties," SPP CEO Barbara Sugg said in a *press release* Oct. 3.

SaskPower's membership became effective Oct. 1. They are now SPP's 115th member.

"Greater integration with the SPP will help to ensure reliable, clean energy is available to Saskatchewan to support our own generating facilities," SaskPower CEO Rupen Pandya said in a press release.

SPP and SaskPower have operated as adjacent entities since October 2015, when SPP's service territory expanded to the North Dakota-Saskatchewan border after the Integrated System's utilities became members of SPP and placed their facilities under the RTO's tariff. The organizations have a joint operating agreement that outlines how the organizations coordinate reliability and transmission functions.

SaskPower line crew at work | *SaskPower*

The utility and SPP will expand the 150-MW tie line that connects them. SPP has been making international transactions with SaskPower since an emergency situation in late 2015, thanks to Canadian interconnections that came when the Integrated System joined the RTO. (See *SPP, SaskPower Make First International Trade*.) ■

— Tom Kleckner

SPP News

SPP Posts Final Markets+ Draft Service Offering

By Tom Kleckner

SPP has posted a Markets+ *draft service offering* that lays out the RTO's proposal to "modernize and enhance" operation of the Western grid.

The document provides the proposed governance structure, market design and other key features of *Markets+*. SPP describes the service offering as providing Western Interconnection utilities that aren't ready to pursue full RTO membership a voluntary, incremental opportunity to realize significant benefits.

The governance and design principles are based on feedback SPP has received from the Western utilities with which it hopes to partner. Participants have until Oct. 28 to provide additional input to the service offering.

The grid operator said the design sessions have narrowed the day-ahead market's basic structure to two possible implementations: a voluntary, financial market with financially binding day-ahead positions that include physical instructions for resources to start and stop, and a multistage process where a reliability-based, physical resource commitment occurs followed by a purely financial and voluntary day-ahead market.

SPP will host a Markets+ *development update webinar* Nov. 1 to discuss funding the tariff development for the offering and commitment agreements. An *in-person meeting* of the Markets+ development group will be held Nov. 15-16 in Westminster, Colo., before the final service offering is released.

RTO staff and Western utilities will continue their work in two phases. First, potential participants and stakeholders will financially commit to design the market protocols, tariff and governing documents. The second phase will begin with FERC approval.

SPP said it will take 21 months to develop and prepare the FERC package at a fixed cost of $9.7 million. It said staff will work with stakeholders to develop a cost allocation approach for the startup costs before the final service offering is issued. Potential participants will pay a monthly rate of $500,000 to support the responses, technical analysis and research necessary to gain final FERC approval.

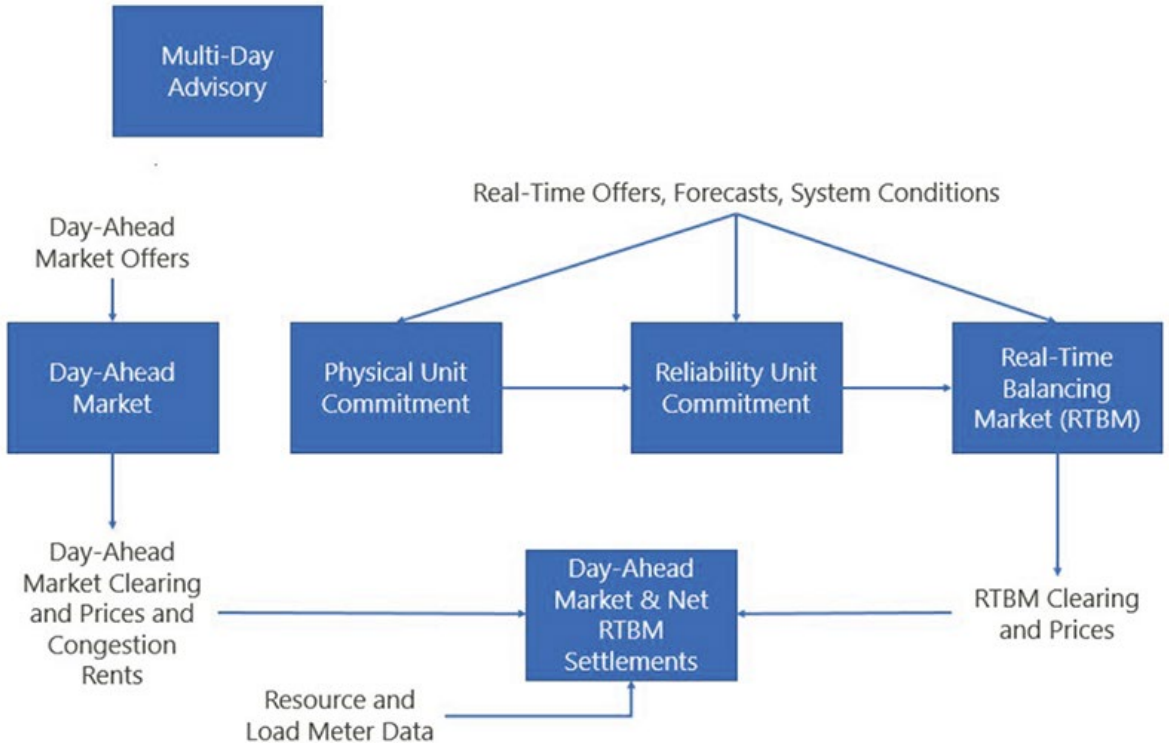
Eleven Western entities have already told SPP they are committed to working with the grid operator to build a Western market that includes "both a workable governance framework and a robust market design." (See *SPP's Markets+ Offering Attracts 6 More Western Entities*.)

Staff Drafting JTIQ Policy

SPP staff told stakeholders they are drafting the governing language to allocate costs for any projects identified in their joint targeted interconnection queue study with MISO. The grid operators plan to assign 90% of the $1 billion study's portfolio to interconnection customers and the remaining 10% to an aggregate of their load, but they were met with some pushback during a Sept. 30 joint stakeholder meeting. (See *Stakeholders Not Sold on JITQ Projects' Cost-Sharing Plan*.)

"We're trying to solidify the principles to where we can build governing language around them and then move it into the regulatory arena," SPP's Neil Robertson, coordinator of system planning, told the Seams Advisory Group Friday.

Staff said they plan to post a policy paper this week designed to gain approval for the cost allocation mechanics and methodology that the SPP region will use. They have scheduled meetings with state and federal regulators to secure their buy-in and hope to get approval from the Regional State Committee in January. The goal is to make the necessary changes to the joint operating agreement and file with FERC in the first quarter. ■



SPP's proposed energy and operating reserve margin functions. | *SPP*

Company Briefs

SEPA Appoints Sheri Givens as President, CEO

The Smart Electric Power Alliance (SEPA) last week announced that Sheri Givens, a vice president at National Grid, will take over as president and CEO in November.

Givens will replace long-time SEPA President and CEO Julia Hamm, who will retire.

Givens oversees U.S. policy and regulatory strategy at National Grid.

More: *SEPA*

Vistra Moves to Extend Comanche Peak Nuclear Plant Operations

Vistra last week announced it is seeking to extend the operation of Luminant's Comanche Peak Nuclear Power Plant through 2053, 20 years beyond its original licenses; Vistra has submitted its application to the Nuclear Regulatory Commission.

The current licenses for units 1 and 2 extend through 2030 and 2033. The company is applying to renew the licenses through 2050 and 2053, respectively.

More: *Vistra*

Rivian Recalling Nearly All Its Vehicles over Loose Fastener

Electric truck and SUV maker Rivian last week announced it is recalling about 13,000 vehicles to tighten a loose fastener that could potentially affect drivers' ability to steer.

A fastener connecting the front upper-control arm and steering knuckle may not be torqued enough. There have been seven reports potentially related to the issue, but no injuries have been reported, Rivian said.

More: *The Associated Press*

Rivian Produces More Than 7,000 Vehicles in Q3

Rivian Automotive last week announced it produced 7,363 vehicles at its facility in Normal, Ill., and delivered 6,584 vehicles in the third quarter of this year.

The company produced 4,401 and delivered 4,467 vehicles in the previous quarter.

Rivian reiterated its full-year production target of 25,000 vehicles.

More: *Reuters*

Hyundai Mobis to Invest $1.3B in EV Parts Plant in US

Hyundai Mobis will invest $1.3 billion through 2030 to build an EV parts plant in the U.S., the company said in a regulatory filing last week.

The investment, which is part of a $5.5 billion investment the Hyundai Motor Group promised President Biden in May, will be made by Mobis America beginning in 2023.

The location of the factory has not been announced.

More: *Korea JoongAng Daily*

Federal Briefs

Senate Committee Approves White's TVA Nomination

The Senate Committee on Environment and Public Works last week approved the nomination of Kentucky's Lyon County Judge-Executive Wade White to the Tennessee Valley Authority Board of Directors.

Senate Leader Mitch McConnell originally recommended White to President Biden.

The nomination now goes to the full Senate for consideration.

More: *The Herald Ledger*

Nations Agree to Curb Flying Emissions by 2050

The International Civil Aviation Organization and its members last week pledged to drastically lower greenhouse gas emissions from the world's airplanes by 2050.

Emissions from commercial aviation made up about 3% of global emissions in 2019 and surged more than 30% in the decade before the COVID-19 pandemic.

The richest 20% of people worldwide take 80% of the flights, according to estimates by the International Council on Clean Transportation. The top 2% of frequent fliers take about 40% of the flights.

More: *The New York Times*

US Wind, Solar Tripled over Past Decade

The U.S generated three times as much renewable electricity from the sun and wind last year in comparison to 2012, according to analysis released last week by the Environment America Research and Policy Center and the Frontier Group.

Among the dashboard's key findings was evidence the U.S. produced enough wind energy to power 35 million homes in 2021 — or 2.7 times as much as in 2012. The nation also generated enough solar energy to power 15 million homes — or 15 times as much as in 2012.

Americans also purchased nearly 647,000 plug-in electric cars in 2021 — a 13-fold increase from 2012.

More: *The Hill*

White House Takes Closer Look at Gasoline Export Ban Option

White House officials last week asked the Energy Department to analyze the possible impacts of a ban on exports of gasoline, diesel and other refined petroleum products.

An export ban would mark the most radical step yet by the Biden administration to tackle prices that surged over the summer and have risen again recently, just four weeks before midterm elections. The DOE is said to be providing insights on the economics at play and evaluating all tools on the table.

More: *Bloomberg*

White House Rules Out Ban on Natural Gas Exports this Winter

The White House has ruled out any ban or curbs on natural gas exports this winter, in a bid to help alleviate energy shortages in Europe, according to two people involved in the discussions.

President Joe Biden committed to deliver 15 billion cubic meters of liquefied natural gas to Europe following Russia's invasion of Ukraine and has already surpassed that goal. Further analysis has only cemented support for ongoing exports, although rising energy costs and a colder-than-expected winter could test Biden's commitment. A ban has not been seriously considered, a U.S. official said.

More: *Reuters*

Sen. Warnock Introduces EV Tax Credit Bill

Sen. **Raphael Warnock** last week introduced a bill that would tweak the requirements for electric vehicle tax credits amid complaints from foreign automakers expanding in the U.S. that the law puts them at a competitive disadvantage.

Before the Inflation Reduction Act was signed, EVs built by Hyundai Motor brands Hyundai, Kia and Genesis qualified for tax credits of as much as $7,500. But the law requires vehicles be assembled in the U.S., Mexico or Canada and meet certain material sourcing rules to qualify. Once Biden signed the legislation, EVs that are assembled overseas no longer qualify and the automakers say that puts them at a disadvantage to models built in North America.

Warnock's bill would give companies like Hyundai time to ramp up production in the U.S. before the final assembly and battery material sourcing rules kick in. If the legislation passes, it would delay the battery sourcing provision until 2025 and the final assembly requirement until 2026. The adjustments would allow Hyundai vehicles to qualify for the tax credits until the company's Bryan County, Ga., plant is completed in 2025.

More: *The Atlanta Journal-Constitution*

State Briefs

ARIZONA

SRP Scolds Board Members After Letter Opposing Gas Plant Expansion

Four Salt River Project board members were censured by a majority vote of the board of directors last week. The action stemmed from a June letter written by the four members to the Corporation Commission urging it to oppose the reconsideration of doubling the size of the utility's gas-fired power plant in Coolidge.

In the letter, board members Randy Miller, Nick Brown, Krista O'Brien and Kathy Mohr-Almeida said they "continued to harbor great consternation from SRP's proposed expansion of the Coolidge Generating Station and believe that the commission should not rehear this issue until SRP has a better understanding of this project's impact on customers' electric bills."

The board also stripped the four of their committee assignments through the end of the year.

More: *KNXV*

CALIFORNIA

Palo Alto Aims to be Carbon Neutral by 2030

The Palo Alto City Council last week unanimously adopted the goal of making the city carbon neutral by 2030.

The new target builds on the city's existing goal of cutting carbon emissions by 80% by 2030 in relation to 1990 numbers. So far, Palo Alto has reduced its emissions by about 50%, thanks in large part to its switch in 2013 to a fully carbon-free electricity portfolio.

The council also approved the goals and key actions of the city's new Sustainability and Climate Action Plan, a document that will serve as a road map to carbon neutrality.

More: *Palo Alto Online*

COLORADO

Xcel Counting on Delayed Solar Projects to Meet Demand in Summer

In filings with the Public Utilities Commission, Xcel Energy said it is facing "resource adequacy challenges" and that a waiver to add more resources is "critical to serving the company's customers" as it may be short on electric generation and reserves for the summers of 2023 and 2024.

The key to meeting next peak demands are two large solar projects in Pueblo County that will miss their end-of-year deadlines but may be online by the end of next summer.

In the last few months, Xcel has been able to fill about two-thirds of its projected 2023 deficit, leaving it short 49 MW for the summer of 2023. In 2024, the company is projecting a 270 MW shortfall with a peak load of 7,145 MW. However, the estimates are based on the delayed solar projects that are under construction and coming online next year.

More: *The Colorado Sun*

CONNECTICUT

State Pays $7.3M for Natural Gas Plant in Hartford

Connecticut has paid $7.3 million for a natural gas power plant in Hartford to heat and cool more than a dozen buildings, saying the acquisition will save money and improve energy efficiency.

The Department of Administrative Services projects savings of more than $20 million in 20 years over the current contract to purchase energy from the Hartford site, a natural gas plant with fuel oil as backup stored on site.

The purchase was made despite an executive order by Gov. Ned Lamont in 2019 requiring the Department of Energy and Environmental Protection to analyze and recommend strategies to achieve a 100% zero carbon target for the electric sector by 2040.

More: *Hartford Courant*

FLORIDA

46K LCEC Customers Still Without Power Following Ian

More than 46,000 Lee County Electric Cooperative (LCEC) customers remained without power last week following Hurricane Ian.

LCEC said it had restored power to 91% of customers but remained the only utility in the state where a sizable number of customers were unserved. As of Sunday, there was still no power to 10,946 customers on Sanibel and 7,398 on Pine Island, days after a temporary bridge provided land access to Pine Island. The only bridge to the island had been washed out by Ian, which made landfall on Sept. 28.

More: *Florida Politics*

PSC Allows Utilities to Harden Grid

The Public Service Commission last week approved, with some changes, long-term plans to bolster the grid submitted by Florida Power & Light, Duke Energy, Tampa Electric and Florida Public Utilities.

The plans were tied to a 2019 state law that passed after Hurricane Irma, Hurricane Michael and other storms caused widespread power outages.

The utilities have until Oct. 25 to file revised plans. The commission will hold a hearing to determine the costs that will be passed along to consumers.

More: *WJCT News*

LOUISIANA

Treasurer Pulls State Money out of Firm, Citing 'Anti-fossil Fuel Policies'

Treasurer John Schroder last week said the state is pulling $794 million out of the BlackRock investment firm over reports that BlackRock has urged companies to embrace environmental, social and governance investment strategies, including climate change initiatives.

"They are pushing their agenda contrary to the best interests of the people whose money they are using," Schroder said in a statement Wednesday.

Schroder said $560 million has been removed so far and $794 million will be out by the end of the year.

More: *Nola.com*

MAINE

Governor's Energy Office to Intervene in Versant Power Rate Request

The Governor's Energy Office last week announced it will formally oppose a rate increase sought by Versant Power after the utility asked the Public Utilities Commission for a 32% rate increase.

Versant Power, the state's second-largest utility, would raise the average customer's bill by around $13.

Gov. Janet Mills said she understands the need to strengthen and improve the grid, "but the timing must be balanced against costs now facing Maine people and businesses today."

More: *Sun Journal*

MICHIGAN

Ann Arbor Making EV Drivers Pay at Downtown Chargers

After a decade of providing free charging for EVs at downtown parking facilities, the Downtown Development Authority last week implemented new user fees to cover electricity and other costs.

Drivers must now pay 25 cents per kWh to charge their cars at downtown EV spots. That is on top of regular parking fees, which are $1.20 an hour.

About 10 cents covers the DDA's cost for power from DTE Energy, while 7 cents goes toward administrative costs. About 2.5 cents goes to ChargePoint, the company that operates and maintains the chargers, with the remaining 5 cents going to City Hall.

More: *MLive*

OHIO

FirstEnergy Fights to Keep Bribery Scheme Records Private

FirstEnergy Corp., which has admitted to spending tens of millions bribing top government officials, asked the Public Utilities Commission to shield documents about its bribes from the public.

The company argued that release of the records would undermine a pause on the investigations made at the behest of federal prosecutors working on the case; that the records aren't the Ohio Consumers' Counsel's (OCC) to share; that they're "commercially sensitive;" and that they violate FirstEnergy's rights laid out in the protective order.

The OCC, which has sought a fuller picture of the bribery scheme, said the company has repeatedly misused its confidentiality rights. Moreover, the OCC said the protective order says if the records are requested by the public, only a "court of competent jurisdiction" can block the request. While the PUC mimics basic judicial procedure, the OCC argued that FirstEnergy should be making its case in a courthouse and not at an administrative agency.

More: *Ohio Capital Journal*

OREGON

DEQ Issues Fine to Company for Fraudulent Carbon Credits

The Department of Environmental Quality last week fined Thompson Technical Services $2.7 million for falsely claiming $2 million in credits through a state greenhouse emissions reductions program and selling them to a fossil fuel distributor.

In June, TTS Charging reported that it had provided nearly 15 million kWh for vehicle charging from three stations, and the department awarded the company about 16,000 credits. However, the charging stations didn't exist. Nevertheless, TTS Charging sold those credits for about $1.8 million to Elbow River Marketing, a fossil fuel distributor and marketer based in Calgary, Canada.

In addition to the fine, the DEQ revoked the company's ability to participate in the Clean Fuels Program and its remaining 89 credits. The company must purchase credits to replace the 16,000 that it received from the DEQ and transferred to the marketing company.

More: *Oregon Capital Chronicle*

WEST VIRGINIA

Appalachian Power, Wheeling Power Seek Rate Increase

Appalachian Power and Wheeling Power last week asked the Public Service Commission for a $297 million rate increase.

The rate increase would add $18.41 (12%) to monthly bills; customers now pay an average of $155.56 per month.

The companies say the increases are meant to recoup expenses from limited coal supplies and purchasing power through contracts with other utilities.

More: *The Intelligencer*