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YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

EMPOWER 25

RTO Insider Acquired by Yes Energy

Yes Energy

RTO Insider LLC, which has been covering the U.S.' wholesale power markets since 2013, has agreed to be acquired by Yes Energy, which provides data, tools and analysis on the same markets.

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SPP

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FERC/FEDERAL ISO-NE

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In this week's issue

RTO Insider Acquired by Yes Energy

RTO Insider LLC, which has been covering the U.S.' wholesale power markets since 2013, has agreed to be acquired by *Yes Energy*, which provides data, tools and analysis on the same markets.

"We are thrilled about this merger and the opportunities it presents for our customers, employees and stakeholders," said Michael McNair, CEO of Yes Energy. "Yes Energy and *RTO Insider* share a passion to serve complex power markets and a commitment to excellence. We will provide the deepest coverage of RTO market data, rules, regulations and policies in the industry."

Rich Heidorn Jr., editor-in-chief and publisher of *RTO Insider*, said the site's news coverage will be enhanced by incorporating real-time and historic power market data and deeper analysis from Yes Energy. *RTO Insider* will continue to be available as a separate subscription and will maintain its commitment to unbiased coverage.

Heidorn will continue to oversee *RTO Insider* and will lead its integration with Yes Energy. Ken Sands, senior vice president editorial, and Adam Schaffer, senior vice president sales and marketing, will continue running *RTO Insider*'s daily operations. All *RTO Insider* customer plans and contacts will remain the same.

Yes Energy employs more than 300 energy analysts, database architects, application developers and economists at nine offices in the U.S., Japan, the U.K., Romania and New Zealand, including its headquarters in Boulder, Colo. | *Yes Energy*

Yes Energy employs more than 300 energy analysts, database architects, application developers and economists at nine offices in the U.S., Japan, the U.K., Romania and New Zealand, including its headquarters in Boulder, Colo.

Its *eight products* provide ISO/RTO data, locational marginal prices, FTR auction results, transmission and generation outages, real-time generation and flow data, and load and weather forecasts. Its customers include traders, analysts, asset managers, asset developers and risk managers.

The company was founded by McNair in 2008 to help power market participants optimize their daily trading and hedging operations.

RTO Insider is the fifth acquisition Yes Energy has made since 2022, when it obtained *financial backing* from *Accel-KKR*, a technology-focused private equity firm.

McNair announced the acquisition to more than 300 Yes Energy customers March 5 at *EMPOWER 25*, its annual summit, in Denver. He said acquiring *RTO Insider* was another step toward completing Yes Energy's "Power Market Operating System."

RTO Insider brings Yes Energy "a new kind of product platform through which we can deliver the news on policy, but also cover market news, events on the grid and provide in-depth analysis of physical changes to the grid," McNair said. "You'll see there are a lot of boxes being ticked here where *RTO* can benefit from or contribute to our operating system."

Heidorn shared his vision for what he called "the second chapter" of *RTO Insider* at the conference.

Yes Energy CEO Michael McNair announces acquisition of *RTO Insider*. | *Kenneth Wajda / Yes Energy*

"What really excites me about joining Yes Energy — aside from getting to work with Michael and his terrific team — is that we will have access to FTR market results, real-time transmission flows, modeling results from long-term studies and other information that will allow us to expand our coverage," he said.

Heidorn founded *RTO Insider* with his wife, Merry Eisner-Heidorn, who died in May 2024.

The idea behind *RTO Insider* was to help stakeholders monitor rule changes that matter to them and alert them to when they should begin attending the meetings themselves to advocate for their interests.

Other publications only cover FERC's ultimate decisions, what Heidorn likened to the small part of an iceberg that is above water. "That means that if you are not in those stakeholder meetings, you're like the captain of the Titanic, with no visibility of that iceberg until it's too late to change course," he said.

RTO Insider remains the only news source with reporters covering RTO/ISO meetings in person.

RTO Insider Editor and Publisher Rich Heidorn Jr. describes "the second chapter" of *RTO Insider* as a part of Yes Energy. | *Kenneth Wajda / Yes Energy*

In addition to its flagship product, *RTO Insider*, the company publishes *ERO Insider*, which covers the Electric Reliability Organization (NERC and its regional entities) and *NetZero Insider*, which covers state and federal climate policy. ■

Pat Wood Talks Power Markets' Past and Future at Yes Energy Conference

By James Downing

Competitive markets might not have the same level of support as they did early in Pat Wood's career, but the former FERC chair believes the politics will swing back in their direction.

"Growing up in the Reagan era, you did have a big faith in free markets," Wood told Yes Energy's EMPOWER Conference on March 5 in Denver. "I know that's a little bit under attack these days, but I think truth will prevail. We'll get through this rough period here and get to the other side."

Wood was a FERC staffer when the commission was opening up the interstate natural gas markets in the 1980s. The markets worked well and opened new supply, so that by the 1990s, industry and regulators moved onto tackling electricity, recalled Wood, who is now CEO of Hunt Energy Network.

"FERC, at the same time, as we did in Texas in the mid-'90s, decided, 'Let's do the same magic trick on the power markets, because God knows, they could use it,'" Wood said.

Wood was the chair of the Texas Public Utility Commission under Gov. George W. Bush and was appointed chair of FERC after Bush was elected president. Texas had a law that required its industry to move at the same pace as the federal government, so Wood and other policymakers followed the Clinton administration's work around Order 888 and the basic requirements for ISO/RTOs. That process gave Texas an example of what not to do in the form of California.

"We figured out what they did wrong, and we did it good," Wood said. "So, we've been able to go to a deep, retail, deregulated market in Texas."

Wood moved over to FERC in time to clean up the fallout from the Western Energy Crisis and to help set up the organized markets operating in interstate commerce.

"That was my job, my four years at FERC, to get all these markets set up into being RTOs and ISOs," Wood said. "So, we pulled California back out of the ditch. You may argue it's still there, but I think they've actually come a long way."

Pat Wood talks power markets' past and future March 5. | *Kenneth Wajda / Yes Energy*

Part of the lesson from California was that the markets needed to be monitored. FERC required RTOs to have market monitors and won new enforcement authority from Congress a few years after the crisis.

"We really just assumed that we could wave a magic wand and things would be competitive," Wood said. "Folks, this industry was vertically integrated, regulated to the toenails for 100 years. So, you can't just wave the wand overnight and say, 'Oh, you're competitive.' We got to kind of undo the damage that's done by the regulated enterprise. And so that took some time, and it still is, I guess, a project that's not complete."

Market power mitigation is important to that project, but as the markets mature with regional planning and resource adequacy constructs, that mitigation can be wound down, he added.

One of Wood's biggest regrets was the failure of standard market design because that would have made it easier for competitors to get into the business all around the country. As the markets evolved, that happened naturally, but Wood said it was more like "Spanish and Portuguese" than dialects of the same language.

Now the growth of new technologies including intermittent renewables and storage, which Hunt helps develop, are leading to new realities on the grid.

"I do think that as grids move to more and more renewables, which is surprising to some, Texas is probably going to go ahead of California, and pretty much anywhere else in North America, and catching up with some of our people in the world," Wood said. "We're moving to a much more renewable-heavy grid, and so that world needs a different set of assets than we have had historically for those last 100 years."

Hunt has rolled out storage around the Texas grid and has also started investing in small, dispatchable peaking generators that only run an average of 100 to 200 hours a year, as those growing intermittent resources need to be balanced, he added. ■

Fears of 'Phantom' Loads, Stranded Assets Aired at Yes Energy Conference

By Rich Heidorn Jr.

Peter Kelly-Detwiler | *© RTO Insider LLC*

DENVER — Prospects of load growth driven by electrification and artificial intelligence have buoyed utility stocks in recent months, but attendees at Yes Energy's annual summit last week questioned how much of the load will materialize and warned of the potential for stranded assets.

Independent consultant Evan Bixby, former vice president of strategy and analytics for Pine Gate Renewables, called for more transparency on potential loads.

"Right now, it's really a black box," he said during an *EMPOWER 25* panel discussion March 6 on power market dynamics impacting asset development.

"Where is this load going to be? How large is it going to be? … How is it actually going to participate in the market?" he said. "Whether it's crypto, [data center] hyper-scalers, industrial facilities … they all participate in very different ways."

Bill Thomas, chief energy officer for *CleanArc Data Centers*, said the prototype data center envisioned in his company's 2021 business plan — which assumed only a migration to cloud computing — was to serve 24 MW of critical information technology. As a result of increased demand from AI, the company's first data center, due to go online in Virginia in 2027, will serve 134.4 MW of IT demand.

"The market has completely taken off, to a point now where it's unreasonable and unsustainable in a lot of ways," he said during a conversation with Isaac Velander, Yes Energy's chief product officer.

Evan Bixby | *Bixby Analytics*

The 15 states that make up 80% of expected load growth from data centers are not ready for the increased demand, Thomas said.

"No chance," he said. "It's somewhat akin to what happened during the early California [renewable portfolio standard] days … and they had to kind of revamp the way that they were thinking about that generator interconnection queue. And they came up with standards and rules, and everything was transparent, and it was auditable, and there were milestones and performance requirements. That doesn't exist on the load side. … It's basically been, 'Hey, I need 5 MW, do you have a circuit for me?' And utilities would say, 'Yeah, sure, great. More retail load. Awesome. Let's do it now.'

"They're trying to figure out how to do this and how to do it fairly. The reality is that there's no roadmap and there's no standardization in it, so the utilities are really struggling to keep up."

Thomas also questioned whether natural gas generation will benefit as much as believed from the data center boom.

"Natural gas has become all the rage in data center world, and there's a lot of people that are going around talking about it. But there's not a lot of people who are going around actually providing solutions to data center operators with natural gas," he said. "I talked to the large [original equipment manufacturers] that make the machines — the gas reciprocating engines and turbines — and they're not seeing the demand actually hit their order books. They're hearing the noise. They have channel partners flittering all around the world, proclaiming to be selling gigawatts of this stuff, but it really hasn't happened yet."

Thomas said his company won't rely on centralized gas plants for backup. "We

want to have our redundant generators, which are redundant on a one-for-one megawatt — actually more than that — basis behind the meter; we want to use gas reciprocating engines instead of tier 2 or tier 4 diesel engines."

Thomas said a 600-MW data center could consume 200,000 dekatherms of gas daily. "Now, we're not going to do that forever, but we might do it for a couple of years. And so the infrastructure required to get that gas to our facility, and then our ability to actually get those molecules, is going to be critical, and it's going to weigh on the gas system as well."

Peter Kelly-Detwiler, co-founder of NorthBridge Energy Partners, warned that utilities building generation to serve AI data center loads could be left with stranded assets if the number of AI players shrinks over time, as happened with search engines in the dotcom boom.

"We all know there were a whole bunch of claimants to the throne of search engine, and eventually, only one of them made it to the top," he said in his keynote address. "And if you don't believe me, you can go ask Jeeves. …

"There will be carcasses on the road" among the current AI competitors, he added. "And the question then is, do the other players in the space buy up those data centers, or does something else happen?"

He said the longest contracts for AI data centers are for 10 to 12 years after a four-year "ramp" period.

"And then there's no commitment after that. If the company exits the scene, they pay an exit fee, assuming they still have the capital to do it. So you have this 30- to 40-year time frame for your supply assets, and you have a four-year ramp and then a 12-year temporal period for your contracts. So we have this really significant potential mismatch between load and the … supply resources. … Woe to the utility that builds all this stuff, and then somebody goes away."

Bill Thomas, chief energy officer for CleanArc Data Centers (left), was interviewed by Isaac Velander, Yes Energy's chief product officer, on the role of data centers in grid dynamics. | *Yes Energy*

Kelly-Detwiler said it's too soon to know whether the current load projections are a new bubble. "But we've gotten this wrong before," he said. "Our forecasts in the past, for years and years and years, have suggested we were going to have a much larger power grid than we had today, and then efficiencies kick in."

He also warned there are likely "phantom" load applications, just as generation developers file more interconnection requests than they expect to complete. A *bill introduced* in the Texas Senate would require data center applicants to divulge where else they're also seeking power.

"I wager a year from now, we have a different conversation. Because really, the data center conversation is only two years old," he said. "As a utility industry, I would argue that we're sitting in a situation which is one of the riskiest we've ever had in terms of capital allocations and the possibility for stranded assets." ■

Overheard at Yes Energy's EMPOWER 25

DENVER — The Trump administration, pending ERCOT market changes, the future of wind power generation and uses for artificial intelligence were recurrent themes at Yes Energy's annual summit, *EMPOWER 25*, held March 5-7. Here's some of what we heard.

More than 300 Yes Energy customers attended EMPOWER 25, its annual summit, in Denver on March 5-7. | *Kenneth Wajda / Yes Energy*

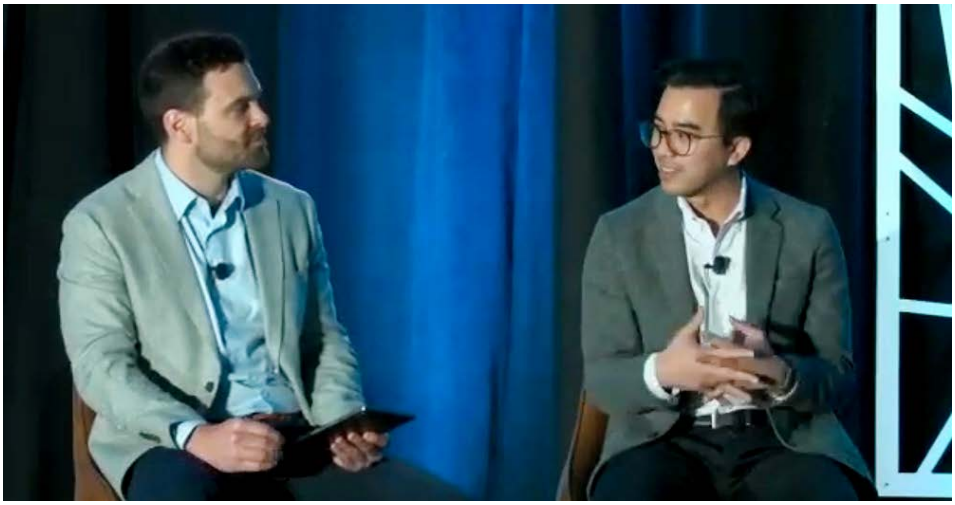
Trump Administration Shakes Things up

Former FERC Chair Pat Wood III, CEO of Hunt Energy Network, was among the speakers expressing concern over President Donald Trump's first few weeks in office.

"There's a lot of things I like about the last six weeks, but some that I don't, like taking treasured institutions and kind of hitting a wrecking ball to them. FERC is one of those," he said. "I think FERC will be fine. I've seen the statements of the new chairman there being pretty supportive of being able to work all this out, and yet I know some quality people are leaving the organization, and I do worry about the loss of that institutional knowledge that has really made markets work seamlessly and work more effortlessly than they probably should have, because you had the right people there."

Sonya Gustafson, general manager of data services for Equilibrium Energy, which uses AI to optimize energy portfolios, said she is concerned over the potential loss of data compiled by EPA, the Energy Information Administration and other federal agencies.

"One of my biggest challenges is access to as much information as possible; that allows us to create accurate renewable energy forecasts," she said. "The threat of that going away does create a little bit of nervousness. We're fortunate in that for weather, we can go potentially to European models, but at the same time, it does create a shift in our businesses. So that's been top of mind recently: making sure I'm archiving as much as possible and finding secondary and third sources for a lot of the information we need to fully optimize."



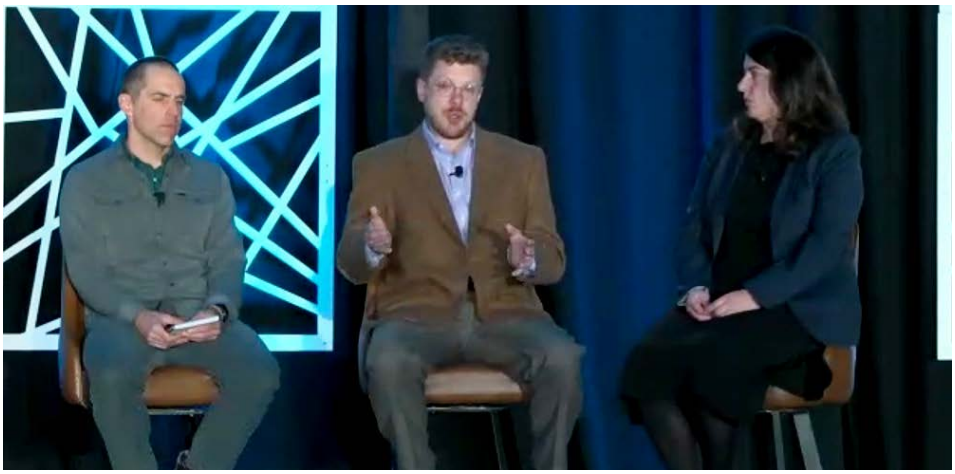
Cliff Rose, senior product manager for Yes Energy (left), moderated an EMPOWER 25 panel on power market dynamics impacting asset development with Ryan Hakim, Cordelio Power. | *Yes Energy*

"The uncertainty is really high right now," said Emma Konet, CTO of Tierra Climate, a marketplace for grid-scale batteries to sell carbon offsets to corporate buyers. "I think developers with projects in various stages of the interconnection queue are now a little bit uncertain about what the [investment tax credit] is going to look like — and maybe it's going away."

She said although falling battery costs have driven a lot of battery deployment in California and ERCOT, the ITC will be needed for widespread deployment in MISO and SPP. "So I definitely think that's a risk."

Leah Kaffine, senior director of integrated energy systems planning for Pattern Energy Group, which operates wind, solar, transmission and energy storage projects, expressed concern over the fate of the Inflation Reduction Act and the Department of Energy. "Pattern Energy, as a developer of transmission … we hope that maybe that will be spared," she said.

Independent consultant Evan Bixby, former vice president of strategy and analytics for Pine Gate Renewables, said he is concerned over tariffs and supply chain risks. "Just the overall attitude of the federal government towards renewables is a little bit threatening," he said. "I'm



Also on the power market dynamics panel were (left to right) Judd Rogers, Scout Clean Energy; Evan Bixby, Bixby Analytics; and Leah Kaffine, Pattern Energy Group. | *Yes Energy*

very confident in the renewable energy industry. It's weathered storms before, and it's a very creative, very passionate, very driven industry. So, [I'm] confident that we will be able to figure it out. But that doesn't mean that there won't be headwinds."

Anticipating ERCOT Market Changes

ERCOT's real-time co-optimization and battery project (RTC+B), set to go live in December, was mentioned at the conference frequently.

"We're in a little bit of purgatory right now," said Drew Peine, vice president commercial for Hunt Energy Network, which is building energy storage in ERCOT.

"We're going into this kind of unknown with RTC+B. You've got the day-ahead markets that are going to be financial, both energy and ancillary products, and then you've got that five-minute optimization on top of it. ERCOT is writing the rules as we speak. [It is] a little bit frustrating that we don't have all the rules right now [that] we need to start, but we're participating in that process with our regulatory team trying to understand what ASDC [ancillary service demand curve] is, first of all, and then what it means for our optimization. And … we need to be there on that Day 1." (See *ERCOT TAC Opens Discussion on Proposed RTC Changes*.)

Gustafson predicted an "exciting" first couple months. "Whenever there's new products launched, there's more volatility. Later on, we may see slightly more depressed prices, but I'm excited for the first three or four months."

"A lot of people, I don't think, fully appreciate how dynamic this market's going to be, and they're going to be kind of stuck in their old ways," Peine added.

"What's really interesting is, once we get to real-time optimization, they have nothing to train on. We have no real-time price data for ancillary services," Konet said. "So, I think that's going to be a really interesting dynamic."

Uses of Artificial Intelligence

AI isn't just driving data center growth, speakers said. It's also taking an increasing role in the work lives of power professionals.

"I think I spend more time talking to ChatGPT than to any human in my life right now," Gustafson said. "It's an awesome platform to learn, and it's something that I use every day when I'm developing code. It makes me faster."

"Asset optimization has been around forever. But I think where AI and [machine learning] and these kind of neural net type models can really come in is in the inputs to those optimizations," Konet said.

Peine said AI will become increasingly important. "The amount of data that we consume is phenomenal; I just cannot believe how much data we consume on a daily basis," he said.

Peter Kelly-Detwiler, co-founder of NorthBridge Energy Partners, said he uses *Perplexity AI* regularly — but still reads 44 newsletters, up from 42 with the recent addition of two on data centers.

"People have told me, 'Why the heck do you read 42 newsletters — now 44 — and scan all that instead of teaching an AI tool to give you what you need?' My answer is, I don't trust yet that I'm going to ask it the right things to look for. And so much of my learning is still accidental.

"When I used to go into a library, the book that I was looking for was not the one that was usually the most valuable to me. It was next to it in the stack, in the adjacencies. And I still enjoy the accidental adjacency, because that's when I find so many of the things I didn't know were going to be valuable to me. And I'm afraid of taking my AI lens and making it so narrow that I build biases into it that exclude the broader world that I need to look at, especially for the data that's going to come slamming into my head and destroy a paradigm that I thought I knew. I love when that happens."

Future of Wind Generation

Wind development has fallen way behind solar in generation growth, but it will remain an important player, speakers said.

Jesse Carver, Yes Energy (left), moderated a panel on batteries in evolving markets with (from left): Emma Konet, Tierra Climate; Sonya Gustafson, Equilibrium Energy; and Drew Peine, Hunt Energy Network. | *Yes Energy*

According to EIA, a *record 30 GW* of utility-scale solar was added to the U.S. grid in 2024, 61% of all capacity additions. Battery storage also hit a record last year, adding 10.3 GW. EIA predicts an additional 32.5 GW of utility-scale solar and 18.2 GW of utility-scale battery storage in 2025.

By contrast, wind added only 5.1 GW last year, the smallest amount since 2014, with slightly more (7.7 GW) expected in 2025.

"Wind is a lot harder to develop," said Ryan Hakim, vice president of commercial and corporate strategy for independent power producer Cordelio Power.

"You need a lot of acreage. … There's a lot of things that can kind of go wrong. But if you are able to take a project to completion, there is quite a lot of demand for that product just because … it profiles generally the opposite of solar."

"One of the reasons why we don't see as much wind development is there's a lot of sites that have been picked over," he added. "But another thing to consider is, we've got more technology where you can build bigger turbines, higher towers; where you're able to extract some of the wind in places where you previously hadn't. And so I think there's new regions that are also opening up."

"Solar and batteries pretty quickly saturate themselves, whereas wind diversification as a species will always be highly valued," agreed Kaffine. "And I think, yeah, people find it refreshing and different."

"You can't do it all with just one technology," Bixby said. "You can't do it all with solar and batteries. [You] probably could, but you need to overbuild by a lot. So you need wind in there. … You'll need advanced geothermal. You'll need new types of battery storage technology. You'll need advanced controls to be able to manage all of it [and] new market mechanisms to pay for it." ■

— Rich Heidorn Jr.

Ontario Premier Ford Slaps 25% Tariffs on Power Exports to the US

Levy Adds to 10% Tariff Implemented by Trump Administration

By James Downing

The Canadian province of Ontario on March 9 began adding a 25% surcharge to all power exports to the U.S., a move that could cost up to $400,000 every day it remains in place. (See *Ontario Threatens 25% Tariff on Electricity to US*.)

Ontario's actions come a week after President Donald Trump implemented tariffs that include a 10% levy on Canadian electricity imports. Provincial Premier Doug Ford said the 25% tariff would remain in place until the U.S. drops its fees. (See *ISO-NE Braces for Tariffs on Canadian Electricity*.)

"We will not back down, pausing some tariffs, making last-minute exemptions," Ford said at a press conference. "We need to end the chaos once and for all. We need to sit down, work together and land a fair deal. A deal that gives businesses the confidence to invest; a deal that gives workers the security they need and deserve."

Ford told reporters he could ramp up the tariff or shut off power flows altogether if the trade dispute between the two nations continues to escalate.

Ontario exports power directly to Minnesota, Michigan and New York, but its flows go beyond those states and into other markets, such as PJM, which can see 1,000 GWh per year of imports from the province — a fraction of a percent of its total consumption. Most of the exports to the U.S. go to either Michigan, at 5,440 GWh last year, or New York, at 6,518 MWh, while Minnesota gets just 145 GWh, *according* to Ontario's Independent Electricity System Operator (IESO).

MISO said in a statement that it was still reviewing the impacts of any electricity tariffs from Ontario, which would be assessed on the Canadian side of the border.

"NYISO is analyzing the impacts of the order by the Ontario premier and working closely with the Independent Electricity Operator of Ontario to ensure a reliable grid and stable flows of electricity across interregional transmission lines," the ISO said in a statement. "NYISO expects to have adequate reserves to meet reliability criteria and forecasted demand for New York."

Michigan Public Service Commission Chair Dan Scripps told a local *NPR affiliate* that he did not expect the tariffs to have much impact there because most of the power flows on to other states.

"If a state like Michigan flows our power through and sells it, as the premier said, to Ohio, that means the impact of this surcharge is going to reverberate right across America … not just in Michigan … or New York or Minnesota, but now in all the states," Ontario Minister Energy and Electrification Stephen Lecce said at the press conference with Ford.

Power flowing from Michigan to Ohio means it crosses the seam into PJM, where an RTO spokesman said it does not have any direct links with the province so the extra fees will be handled elsewhere.

While Ontario officials floated some pretty high bill impacts on Americans for the surcharge, the ultimate impact depends on the power markets. Ontario ships excess power south and is generally a price taker, and so its tariffs would only influence wholesale prices if the power was marginal supply for an RTO.

Before Trump's tariffs scrambled North American trade, the big news involving trades between Ontario and the U.S. was a new potential power line being developed by NextEra Energy to ship power directly to PJM under Lake Erie. The Lake Erie Connector made it through recent cuts from the U.S. Department of Energy to be included in one of three National Interest Electricity Corridors. (See *DOE Cuts NIETC List from 10 to 3 High-priority Transmission Corridors*.)

That underwater project was initially proposed by ITC, which upon filing for approval with Canada's National Energy Board back in 2015 said the connector would "provide the opportunity to earn additional export revenues on surplus generation." ■

Why This Matters

While Ontario is a limited supplier of power to U.S. markets, the cost of compounding tariffs could ripple through regions during periods of tight supply.

RMI Argues Regionally Planned Transmission Leads to Unexpected Benefits

By James Downing

Major regional and interregional transmission lines might be big investments, but they tend to produce more benefits than expected, RMI said in a report published Feb. 28.

"*High Voltage, High Reward Transmission*" looked into seven case studies from around the country — in all of the ISOs and RTOs — to look into how they actually benefited residential, commercial and industrial customers.

"There's … huge momentum towards regional planning with [FERC] Order 1920, and we really want regulators and planners to feel confidence in this type of high-voltage, long-distance transmission to meet the energy challenges of today and tomorrow and really provide lasting value for consumers and businesses, especially when we're kind of facing an affordability crisis in this country," RMI's Tyler Farrell, a co-author of the report, said in an interview.

The seven projects were built for different reasons — reliability, economics and meeting public policy — and all of them had benefits that exceeded their costs, even using conservative assessments. They include the Cross-Sound Cable between New York and New England; PJM's TrAIL project; the Paddock-to-Rockdale line between MISO and PJM; MISO's CapX2020 line; SPP's Beaver-to-Oklahoma City line; ERCOT's Bakersfield-to-Kendall project; and CAISO's Valley-to-Colorado River line.

Five of the seven lines were built with economic benefits in mind, and they all had positive cost-benefit ratios. The three projects in which cost-benefit analyses were performed in the planning process all wound up beating those predictions in real-world operations. FERC has a standard that such lines exceed the ratio of 1:1.25; all five beat that easily.

The other two lines were reliability projects, and in addition to keeping the lights on, they led to unexpected economic benefits, RMI said.

Transmission investments are typically meant to last 40 years, but the lines in the study were all paid off in eight to 34 years. Farrell said projects can sometimes keep running much longer than four decades. One example from outside the study is the Pacific DC Intertie, which links the Pacific Northwest and Southern California and has been in operation for more than 50 years.

"When they were built, the administrator for [the Bonneville Power Administration] said that these lines pay for the construction costs of these lines every single year, for their entire lifetime," Farrell said. "And now we're in 2025 and yes, they made investments into those lines since then, but those lines are still in operation and delivering huge savings to people across the Pacific Northwest and in California."

The report looks at three main ways transmission saves money: reduced congestion, access to cheaper generation, and access to renewable sources of generation that meet public policy goals. Some lines also have unique benefits.

"Transmission infrastructure, beyond its initial driver, is designed to adapt to unforeseen changes or events," the report said. "Several projects have enabled the significant integration of renewable resources like solar, wind and storage, far exceeding original expectations because of substantial decreases in technology costs. This has lowered generation costs for ratepayers. Additionally, many projects have played critical roles in maintaining grid reliability during unforeseen extreme events, such as winter storms and heat waves, ensuring that the lights remain on for consumers."

Texas spent billions on the Competitive Renewable Energy Zone lines to connect wind resources to the state's major cities, but an unexpected benefit was that they enabled the electrification of oil and gas drilling in the Permian Basin, the report said.

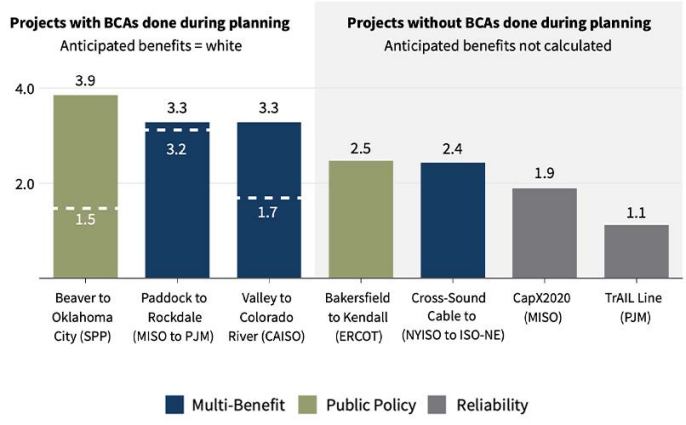
Across all seven of the projects studied, congestion relief savings made up most of the benefits to ratepayers, and the report said it was the most straightforward benefit new transmission offers because it cuts fuel and variable costs, ensuring the grid operates as efficiently as possible.

Another recent RMI report, "Mind the Regulatory Gap," highlighted how most transmission dollars lately were flowing to local projects, which often lack the same oversight as regional and interregional planning processes. It was cited in a complaint consumer groups filed last year asking FERC to address that gap, the comments for which are due March 20. (See *Consumer Groups Seek Independent Oversight of Local Tx Planning*.)

With most transmission costs going into those local projects, the industry is not at risk of gold-plating the grid by shifting more of its focus to regional and interregional projects, Farrell said.

"I actually think that regional planning is the opposite of that, which is really cost-effective planning versus local planning, which is non-cost-effective planning," Farrell said. "It's literally just reliability planning and building the system from the ground up, versus the top down, which is what regional planning looks like." ■

Net present value benefit-to-cost ratio over the 40-year financial life compared with original anticipated benefit-to-cost ratio (white lines)



Cost-benefits ratios for the lines studied in RMI's report, including, when available, the expected savings from the lines' planning processes | *RMI*

Petition Asks FERC to Potentially Claim Jurisdiction over Puerto Rico

By James Downing

Puerto Rican company Pluvia filed a petition with FERC in February asking the commission to find that its proposal to link the territory to the continental U.S. via grid-scale batteries on cargo ships could trigger its jurisdiction over the island (*EL25-57*).

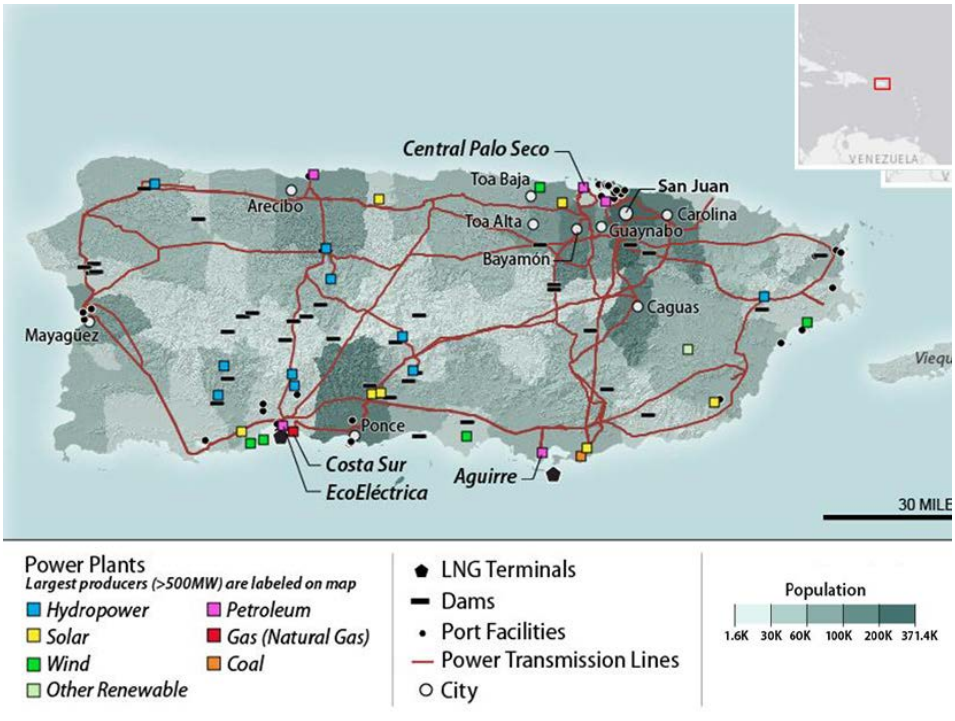
The batteries being shipped back and forth would be storage-as-transmission-only assets (SATOA), and similar projects have been *proposed* using railcars. The mobile storage could also ship power the other way. The firm's filing says the technology could be used for day-to-day shipping and under emergency conditions.

The firm filed its petition in early February, and FERC noticed it a couple of weeks later. It has largely flown under the radar, with only Public Citizen filing a "doc-less" motion to intervene before the comment period closed March 3.

Pluvia describes itself only as "a domestic limited liability company wholly owned by citizens of the United States and organized under the laws of the commonwealth of Puerto Rico, *inter alia*, to produce, transmit and sell electric energy at wholesale." Exactly who is behind the firm is unclear: Its petition was filed by one lawyer, and its incorporation documents with Puerto Rican authorities only list another lawyer.

The state-owned Puerto Rico Electric Power Authority (PREPA) entered into contracts with Luma Energy (a subsidiary of Canadian utility Atco and Quantas Services) to run its grid in 2021, and with Genera PR (a subsidiary of the LNG firm New Fortress Energy) to run its generation in 2023. Pluvia told FERC that those deals have kept a monopoly in place, which is overall detrimental to the island's population.

"Public electricity monopolies have been effectively managed by other states, which have cooperated to lower costs and improve service to customers by implementing federal electric competition policy under the" Federal Power Act, Pluvia said. "The government of Puerto Rico's administration, however, has been unsuccessful. The damage Puerto Rico's electricity monopoly has caused is considered a human-made disaster with appalling humanitarian and economic impacts in Puerto Rico that also impact United States taxpayers."



Congressional Research Service

Why This Matters

The Federal Power Act gives FERC broad authority to claim jurisdiction over Puerto Rico if it does connect to the mainland grid via an undersea cable. But it also has the authority to forswear that jurisdiction, and has done so regarding projects that connect ERCOT to the rest of the U.S.

The island was infamously impacted by Hurricane Maria, which in 2017 destroyed the island's power grid and kept some of its residents without power for four weeks.

"It's really not done well since the hurricanes; the reliability of the system is probably about 10 times worse in terms of safety and safety metrics than the U.S. average," Cathy Kunkel, energy consultant for the Institute for Energy Economics and Financial Analysis, said in an interview. "And the reliability has actually declined over the last year or so."

PREPA's system was contracted to Luma and Genera after the hurricane, with Kunkel saying it was not sold outright because that would have put at risk federal disaster relief funds being used to shore up the grid.

High costs and an unreliable power system have been impairments to economic growth on the island and its ability to stop people from moving to the mainland, Pluvia said in its petition.

On top of still running a creaky grid before and after Maria ravaged PREPA's system, the public utility has been bankrupt, which has hampered its ability to attract needed investment, Pluvia said

"PREPA's lack of credit creates a barrier to normal project financing for energy proj-

ects, as financing sources hesitate to bet on PREPA's performance of its long-term contractual obligations to buy electricity in quantities and at prices stated in" power purchase agreements, Pluvia said.

The combination of public monopoly and insolvency leads consumers and investors to a dead end, while creating the misleading appearance of an energy transition through multiple phases of bids and awards that produce contracts needing affordable financing, it added.

While Pluvia and its backers might have run into trouble with securing contacts, Kunkel noted that major deals have been struck recently.

"There's definitely been long-term contracts that have been signed in the last several years," Kunkel said. "There's been a number of new renewable energy contracts and some battery storage contracts and a new natural gas plant contract that was signed in December."

Another trend since Maria has been end-use consumers' increasing adoption of distributed solar and storage, which Kunkel said makes up about 9% of Puerto Rico's electricity consumption.

The issue of FERC jurisdiction over Puerto Rico's grid has come up before, such as when Alternative Transmission filed a petition in 2023 seeking a finding from the commission that its proposed undersea cable would not trigger commission jurisdiction (EL23-14). The project and its details were a little too vague for FERC to give a firm answer, but it did discuss the jurisdictional issues and said it could forswear oversight of Puerto Rico's grid as it has in similar cases involving ERCOT. (See *FERC Weighs in on Jurisdictional Questions over Puerto Rico Project*.)

The Alternative Transmission case came up in Pluvia's petition as it seeks to clarify that its proposal of shipping batteries back and forth by sea could trigger FERC jurisdiction over the island's power system, which the commission said could happen with an undersea cable.

The petition does not ask FERC to claim jurisdiction immediately, but Pluvia said it may request that in future proceedings, and it expressly reserved the right to do so.

Puerto Rico has a version of a state regulator already called the *Energy Bureau*, which was set up about a decade ago to oversee PREPA. IEEFA's Kunkel said it has helped bring some normalcy to the island's regulatory structure.

"One of the problems with PREPA … was that it really had just kind of become a very politically driven entity and was not making decisions based on best-practice, sound utility planning," Kunkel said. "For example, it had not had a base rate case since the 1980s. One of the first things that the Energy [Bureau] did was to have a base rate case."

As for bringing RTO-style markets to the island, it is unclear how much benefit they would bring: Puerto Rico's system is far smaller than any of the continental organized markets, meaning it would lack the benefits that come from centrally dispatching large amounts of generation across a wide footprint, Kunkel said. ■

Texas Stakeholders Grappling with Tsunami of Large Loads

Overheard at Infocast's ERCOT Market Summit

AUSTIN, Texas — An estimated 800 industry stakeholders gathered in the heart of Texas Feb. 25-27 for Infocast's ERCOT Market Summit to discuss and share opinions on the unprecedented expansion of energy demand.

According to ERCOT projections, demand will reach 152 GW by 2030, up 73% from its current record peak of 85.51 GW set in 2023. A flood of data centers, cryptocurrency miners, new residents, and electrification of oil and gas production in the Permian Basin is driving that demand, which will require more generation and transmission and distribution infrastructure.

That has left the Texas grid operator, the industry and the state's policy makers and regulators scrambling to find the best way forward to deal with the coming tsunami.

Legislators have responded with *Senate Bill 6*, which would create rules and policies for large loads looking to hook up to the grid. The bill would hit data centers with minimum transmission charges and require generation co-located with load to serve the Texas grid during grid emergencies.

ERCOT plans to add real-time co-optimization and a new dispatchable reliability reserve service within the year. The Texas Energy Fund, voted into law in 2023, offers about $5 billion for new dispatchable generation. At the same time, the Public Utility Commission is considering whether to approve 765-kV lines into the Permian Basin to serve that load.

Will it be enough?

Why This Matters

The unprecedented flood of load from data centers and other sources will require more generation and transmission and distribution infrastructure.

Infocast's ERCOT Market Summit was expected to draw about 800 attendees. | © RTO Insider LLC

"We're used to integrating 5%, 8% growth … I don't think that we've ever even conceived of the magnitude of loads trying to move in so quickly in such concentrated areas," said Scott Bruns, director of power markets for Enverus. "It's a three-legged stool. It's the load, it's the generation, it's the transmission, and we can generally build all of those in sort of sync and phase. But right now, we're having the conversation of, 'If we build 20 GW of demand tomorrow, do we have the ability to transmit it?' Then, do we have the ability to generate versus whatever generation sources we want to choose?"

"The grid was always built to manage load. Whatever the load wanted to do or whenever the lights came on, generation had to spin up. Whenever the lights were turned back on, [generation] had to back down," said Clayton Greer, vice president of Cholla Petroleum's energy division. "That was all fine for the last 100 years. That has all been turned on its head with these data-center-type loads."

State Sen. Phil King (R) laid out SB6 during a Feb. 27 Senate Business and Commerce hearing, saying, "These large load customers' demand for electricity is requiring ERCOT to plan for load growth at dramatically higher levels than experienced ever in the history of Texas and, frankly, ever in the history of the United States."

In just 2025 alone, Oracle and Open AI announced Abilene, Texas, would be the first site of its $500 billion artificial intelligence network of data centers called the *Stargate Project*. Apple made a big splash with another $500 billion investment in a *server-manufacturing facility* in the Houston region to meet the demand.

Most recently, startup developer Last Energy said Feb. 28 it plans to build *30 micro nuclear reactors*, with a combined capacity of about 600 MW, north of Abilene. The company has filed an interconnection request with ERCOT and is prepping an early site permit with the Nuclear Regu-

latory Commission.

ERCOT told stakeholders in February it had 99 GW of flexible large loads — defined as 75 MW connected to a transmission service provider or 20 MW when connected to a resource request — in various stages of study. In 2022, it had 2.6 MW.

"Some of these requests in excess of 1,000 MW are really starting to pose a risk to things like frequency stability or other kind of larger cascading events that we just haven't seen with loads in the past," said ERCOT's Agee Springer, senior manager of grid interconnections. "The size of these interconnections, I think, is a potential risk for [system] reliability."

Building out ERCOT's aging grid to serve load will not come cheap. The proposed EHV transmission lines into the Permian Basin will cost at least $30 billion, in addition to normal upgrades.

"There's going to be a time sometime in this decade, sometime in the next decade if reform isn't achieved, where a customer will open their bill and more than half of the charges will derive not from their choices in retail electric provider, but in charges that result from centrally planned, socialized cost grid decisions," said NRG Energy's Travis Kavulla, vice president of regulatory affairs.

NRG has joined the party too, saying during its February quarterly earnings conference call that it plans to build 5.4 GW of combined-cycle gas plants to serve data centers in Texas and Virginia. The latter leads all worldwide regions in operational data centers with about 4.6 GW of facilities, more than doubling second-place Beijing.

"One of the things that we'll need to make sure that as we grow the load, that we don't continue to alienate individual customers. … Eventually the consumer is going to notice, and they're going to take up their pitchforks," Bruns said. "And so, we need to make sure that as we bring these loads in, that it's not onerous to the rest of the system."

EHV Lines Offer a Lifeline

One solution to the large load conundrum could be extra-high-voltage lines. ERCOT has proposed 345- and 765-kV lines as options for its Permian Basin Reliability Plan. It also has proposed using EHV facilities as part of an upgraded transmission backbone.

The PUC, faced with a May deadline to decide which way to go, held a workshop *March 7* that featured equipment vendors and infrastructure builders offering their perspectives. Commission Chair Thomas Gleeson said he wants to ensure what he's hearing from the transmission and distribution utilities is "accurate and reflects reasonable expectation from those manufacturers."

The Sierra Club's Cyrus Reed (right) listens to NRG Energy's Travis Kavulla. | *© RTO Insider LLC*

"I know that we're behind on building transmission, particularly to the Permian customers," he said. "There are no solutions. There are only trade-offs, and so we want to make sure that we build enough transmission, particularly to the Permian, where their demand is just going to skyrocket. But it has to be done at a reasonable cost and on a reasonable timeline. Any delay of getting that transmission to the Permian is not acceptable, because we're probably 10 to 15 years behind on what they already need."

The plan is receiving a thumbs up from many stakeholders.

"ERCOT's 765- versus 345-kV plan is some of the best long-term planning I've seen come out of ERCOT in over 10 years," said former Oncor planner and current Owl Electric Reliability Consulting principal Ken Donohoo. "They're finally talking about the right topic, transfer capability, not just about thermal limits or voltage limits or so on. It's about transferring those megawatts across the grid."

"It does sound like 765, especially for the Permian Basin, is the perfect solution," said Sumeet Mudgal, transmission planning manager with photovoltaic manufacturer Qcells. "We have to also think about the contingencies. If we are adding a line that is going to carry 5,000 to 4,000 MW, we can't just build one 765-kV line. We should think of adding another path that is able to carry an equivalent amount of power. I think a 765 backbone transmission is what probably will become our future."

There's a slight kink in the plan.

Texas State Sen. Charles Schwertner (R), chair of the powerful Business and Commerce Committee, filed a bill (*SB1665*) Feb. 27 that requires the PUC to conduct a study before approving a 765-kV line. The study, which would assess costs to residential customers, supply chain and workforce limits, and mitigation of cost overruns, is to be submitted to a third party for review.

"We need to do it now. If we don't do it

now, inflation and supply chain issues will only increase those costs," warned ENGIE's Bob Helton.

How Reliable are Future Projections?

Taking part in a panel discussing ERCOT's market design, Katie Coleman, who represents Texas Industrial Energy Consumers, was asked about the grid operator's load projections and whether all of it will show up. Saying a demand peak of 105 GW or 110 GW is a "better number" than ERCOT's 152 GW projection, "I've said this 1,000 times, like I'm screaming into the void, but you cannot forklift a transmission planning number for resource adequacy purposes. They're measuring two completely different things. There's also this optics issue of the load over here, but you're not counting any of that in the resource adequacy analysis, so you've got to do something to align those two.

"I don't think putting all that load in a resource adequacy analysis is the right thing to do," she added, noting that developers are putting a capacity number in their interconnection request that finds its way into transmission and resource adequacy planning numbers alike.

"I think the other thing that we're seeing is a very different type of interconnection activity than what my traditional industrial and manufacturing clients have done," Coleman said. "You have an end user who wants to use electricity to produce some product. They have their own business plans that they can discuss with the utility. There's just a race to market in this area. You've got people putting in speculative interconnection requests."

Coleman and other speakers also raised concerns with ERCOT's Capacity, Demand and Reserves (CDR) report. Delayed for two months while staff revised the load forecast and renewable capacity, the report indicated negative reserve margins within two years under the most dire scenarios. (See *ERCOT's Revised CDR Report Met with Doubts*.)

"Now, all of a sudden, it looks like Armageddon. Well, the facts on the ground haven't changed really since the prior CDR," Coleman said, saying her clients don't like to put money around the report. "It's a dangerous thing to use these types of tools which are so susceptible to sensitivities and inputs to move big dollars around."

"The CDR itself is a static snapshot in time," Luminant's Ned Bonskowski said. "It does not reflect market dynamism, it doesn't reflect behavioral responses from demand loads, load flexibility. It doesn't reflect market signals that will incentivize supply to come in."

"The more finicky or the more fussy that we get with the CDR, the less useful it is," added Beth Garza, ERCOT's former market monitor now with R Street Institute.

"Even if you doubt the CDR, no one can doubt that Texas is a tight market," Kavulla said. "It's not unreasonable, candidly, for people to have policy concerns around adding incremental loads, and frankly, good luck finding another market and another state that doesn't have those same concerns. Everyone has those same concerns."

Renewables Fight Headwinds

While the focus in Texas may be on dispatchable generation (i.e., nuclear and thermal), renewables continue to set production records that justify ERCOT CEO Pablo Vegas' frequent references to an "all-of-the-above" strategy for resources.

On March 2, renewables set a new mark for renewables-to-load ratio, at 76%. With March arriving like the proverbial lion, wind (28.47 GW), solar (24.82) and storage resources (4.83 GW) all set record highs with the calendar's turn. According to a *January report*, solar and batteries account for 82% of the resources in ERCOT's interconnection queue, or 320 GW of capacity.

Yet the clean energy resources continue to face headwinds at the State Capitol, where proposed legislation (*SB819*) has been filed that would require only

Judd Musser, APA | © RTO Insider LLC

Katie Coleman, TIEC | © RTO Insider LLC

renewable developers to jump through additional hoops for operating permits. Neighboring property owners also would gain new authority to block the developments.

"I'm going to do my best to be diplomatic here," said the Advanced Power Alliance's Judd Musser, who tried his very best. He said the bill is "couched as siting and permitting," except that it's not.

"It's a discriminatory and punitive permitting bill towards two resources and only two resources: wind and solar," Musser said. "It would be a devastating blow to our industry. It would take us from a market here in ERCOT, where we've done the most business for the last 30 years, to probably the place where we would do the least.

"As a state that has thrived in harvesting our own kind of homegrown energy for so long, I think it would be a real shame to jeopardize that in the name of partisan politics or just the fact that maybe somebody doesn't like to look at something," he added.

Musser warned that the legislation will send a negative message to potential investors that could have lasting effects on the state.

"[Investors] want to be here because of a friendly tax environment and access to a skilled workforce and all those things," he said. "If you send the message to them as a legislature that you're going to pull the rug on them or you're going to move the goal post … I think we really risk this Texas miracle that we talk so much about kind of falling by the wayside." ■

— Tom Kleckner

Federal Policy Driving Uncertainty for Developers in the Northeast

By Jon Lamson

WALTHAM, Mass. — The uncertainty around federal funding, permitting approvals and tariffs on trade is creating major challenges for clean energy development in the Northeast, industry representatives said at the Northeast Commerce and Energy Association's annual Renewable Energy Conference on March 5.

Turmoil in the federal government is creating "an atmosphere that is not good for business," said Jeremy McDiarmid, managing director and general counsel at Advanced Energy United. "It's been 44 days, and it seems like forever."

Tariffs on Canadian imports threaten to add "hundreds of millions of dollars in potential costs for New England electric customers," McDiarmid said, noting that this could be "extraordinarily damaging for the ratepayer at the end of the day."

Patricia Tamez, senior adviser at Shell Energy, said the tariffs could be particularly damaging for clean energy technologies with nascent supply chains.

"Everybody needs investment certainty. … Supply chains for a new industry are difficult to set up," Tamez said. "The starts and stops make it very hard to predict what's going to happen."

Tamez also highlighted the significant uncertainty surrounding potential tariffs on electricity imports. Both ISO-NE and NYISO are preparing to collect tariffs on imports if they are directed to do so while simultaneously arguing that electricity should be excluded from the tariffs. (See *ISO-NE Braces for Tariffs on Canadian Electricity* and *NYISO Preparing to Collect Duties on Canadian Electricity Imports*.)

"There is conflicting information from the government agencies on whether a tariff can be collected on the provision of electricity," Tamez said. "This conflict has been noted by many, but the government hasn't yet announced a clear position."

Meanwhile, Hydro-Quebec has considered cutting off exports to the U.S., according to *reporting* by *The Globe and Mail*. The company already faces extremely low reservoir levels because of an extended drought, putting it in "an excellent negotiating position" to potentially pause exports as it recharges its reservoirs, Robert McCullough of McCullough Research noted in an email.

From left: moderator Courtney Feeley Karp, Klavens Law Group; Marianne Perben, ISO-NE; Kate Tohme, New Leaf Energy; Peter Shattuck, Power Advisory; and Elton Prifti, National Grid | © RTO Insider LLC

Why This Matters

Actions by the Trump administration threaten to stall the development of renewables in New England, potentially posing significant challenges to reliability, affordability and decarbonization in the region.

Imports from Quebec have met about 11% of demand in ISO-NE over the past five years, and the RTO has said cutting them off could create "precipitous, adverse consequences" for grid reliability.

Regarding federal funding, Tamez said it appears unlikely that Republicans will fully repeal the Inflation Reduction Act, noting the large amounts of funding that have gone to Republican congressional districts and the "very large coalition that's developed across energy sources to protect the IRA."

McDiarmid said there is "a lot that states can do" to fill the gaps left by the federal government, but he acknowledged that the states lack the "the financial prowess to replace the finances that these federal tax credits can provide."

Speakers said the challenges to clean energy development come at a difficult time for the region, which is preparing for an exponential increase in demand growth over the next couple decades. ISO-NE projects its peak demand to grow from about 25 GW in 2024 to about 57 GW in 2050.

The New England states will need to keep pace with load growth while simultaneously reducing fossil generation, which accounted for the majority of generation in the region in 2024. (See *New*

England Gas Generation Hit a Record High in 2024.)

"We're definitely moving to a world where both the supply and demand both are going to be highly variable and dependent on the weather," said Marianne Perben, director of planning services at ISO-NE.

Michael Judge, undersecretary of energy at the Massachusetts Executive Office of Energy and Environmental Affairs, noted that the state will need to deploy about 24 times more wind and six times more solar than current levels to meet its climate mandates.

"We need to build a lot, and we need to do it really quickly," Judge said. He highlighted the changes to permitting and siting processes enacted by the state in 2024, which are intended to streamline and expedite clean energy infrastructure approvals. (See *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track*.)

For the storage industry, "federal policy uncertainty right now is obviously a huge challenge," said Sean Burke, director of policy at BlueWave Energy. He said the tariffs have created complications for state procurements and power purchase agreements.

New England states are aiming to massively scale up the region's storage capacity in the coming years. The Connecticut legislature has established a storage development goal of 1,000 MW by 2030; Rhode Island has a goal of installing 600 MW by the end of 2033; and Massachusetts plans to procure 5,000 MW over the next five years.

From left: moderator Susan Rogers, Potomac Law Group; Bahaa Seireg, American Clean Power Association; Jeremy McDiarmid, Advanced Energy United; and Patricia Tamez, Shell Energy | © RTO Insider LLC

Hans Detweiler, senior director of development at Jupiter Power, emphasized the importance of soliciting "apples to apples bids" to enable state agencies to see how the bids are priced and potentially adjust the pricing to account for major changes in federal policy.

Detweiler said he remains optimistic about the "long-term opportunity" of storage in the Boston area, adding that "within the Boston load pocket, our view is the volatility is going to come," which will create the demand for storage resources. ■

FERC Approves Power Up NE Tx Filing amid Funding Uncertainty

By Jon Lamson

Amid uncertainty about grant funding from the U.S. Department of Energy, FERC has approved a guarantee for National Grid to recoup all prudently incurred costs for the company's portion of the Power Up New England transmission project if the project is terminated due to factors outside the company's control (*ER25-866*).

The Power Up project aims to build two interconnection points for offshore wind projects in New England. Spearheaded by the Massachusetts Department of Energy Resources (DOER), the project is supported by the six New England states and includes proposed upgrades to transmission infrastructure owned by National Grid and Eversource.

In 2024, DOE's Grid Resilience and Innovation Partnerships (GRIP) program — created by the Infrastructure Investment and Jobs Act (IIJA) in 2021 — awarded a $389 million grant to the Power Up project, estimating the project would create $1.55 billion in electricity savings. (See *DOE Announces $2.2B in Grid Resilience, Innovation Awards*.)

National Grid has estimated its portion of the project — intended to facilitate the interconnection of up to 2,400 MW of offshore wind at Brayton Point in southern Massachusetts — would result in $1.2 billion in electricity savings for the region.

However, the Trump administration has taken a hostile stance to the offshore wind industry and *paused* the disbursement of IIJA funding that it deemed to undermine the *policy priorities* outlined by the administration.

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The Grid Deployment Office (GDO) *lists* the project's funding status as "selected," which indicates that DOE has not issued the final funding award. A DOE representative confirmed this status is up to date.

The Massachusetts DOER — the lead applicant for the project's application for grant funding — did not comment on the status of the funding in time for publication. The GDO also declined to comment.

Significant risks remain even if the grant is awarded by the Trump administration; the funding is contingent on the project coming online within eight years of the finalization of the federal funding agreement. In its filing with FERC, National Grid acknowledged that losing the federal funding would increase the risk of cancellation. (See *First FERC Filings Shed Light on New England OSW Tx Project*.)

In response to the heightened risks, National Grid and Eversource have requested FERC authorization for an "abandoned plant incentive" allowing the companies to recover all prudently recovered costs on their portions of the project if it is canceled. The costs of the project will be allocated to customers in ISO-NE on a load ratio basis, with a base return on equity of about 11%. The companies cannot earn an ROE on the portion of the project covered by the federal grant.

The New England States Committee on Electricity (NESCOE) supported both filings in accordance with agreements between NESCOE and the companies. These agreements authorize the states to cancel the project if the expected costs increase and require the companies to make annual reports on incurred and projected costs.

FERC wrote that National Grid has "shown that the project faces risks and challenges beyond the control of applicants that could lead to the project's abandonment, and that approval of the Abandoned Plant Incentive will address those risks and challenges."

However, the commission emphasized that any recovered costs must be prudently incurred and highlighted potential uncertainty around the federal funding for the project.

Why This Matters

Despite FERC's approval of the filing, the Trump administration's pause on IIJA funding appears to threaten the transmission project's viability.

"The commission's prudence determination could consider the reasonableness of investment decisions given the status of potential obstacles to project development that were reasonably foreseeable including DOE grant funding availability," FERC added.

In its filing Jan. 6 to FERC, a representative of National Grid said the funding award is slated to be executed "in the early months of 2025."

In a concurring statement with FERC's ruling, Chairman Mark Christie wrote that, because the project is driven by state clean energy policies and targets, his concurrence depended on the states' unanimous agreement "for their consumers to bear the costs of this project using a cost allocation formula to which they all agreed."

While the majority ruling noted that National Grid has provided clear evidence the project would create significant congestion cost savings, Christie stressed that the Power Up project "is a public policy project, not a reliability or an economic project, even if there are some ancillary reliability and congestion benefits as there always are with any project."

"As we move into the Order No. 1920-A compliance process," Christie wrote, "this is an excellent example of the opportunity and authority granted to states in that rule to agree to jointly share costs of such projects."

FERC has yet to rule on a similar request made by Eversource, and issued the company a deficiency letter in February requesting more information on potential reliability and cost benefits of the company's part of the project (*ER25-747*). ■

New England Energy Market Costs Grew by over $2B in 2024/25 Winter

By Jon Lamson

New England energy market revenues increased by roughly 150% in the winter of 2024/25 compared to the prior winter, growing from about $1.6 billion to about $4 billion, ISO-NE COO Vamsi Chadalavada *told* the NEPOOL Participants Committee on March 6.

The increased costs were driven by consistently cold weather, Chadalavada said, adding that this winter was the first with lower-than-normal average temperatures since 2014. Despite that, the system did not experience any capacity deficiency events and maintained adequate oil inventories, he noted.

Natural gas accounted for about 40% of the total energy, followed by nuclear around 23%, imports around 21%, hydropower around 5%, renewables around 4% and oil around 2%.

Chadalavada noted that scheduled LNG injections into the gas system increased to 22.4 Bcf compared to the five-year average of 16.6 Bcf.

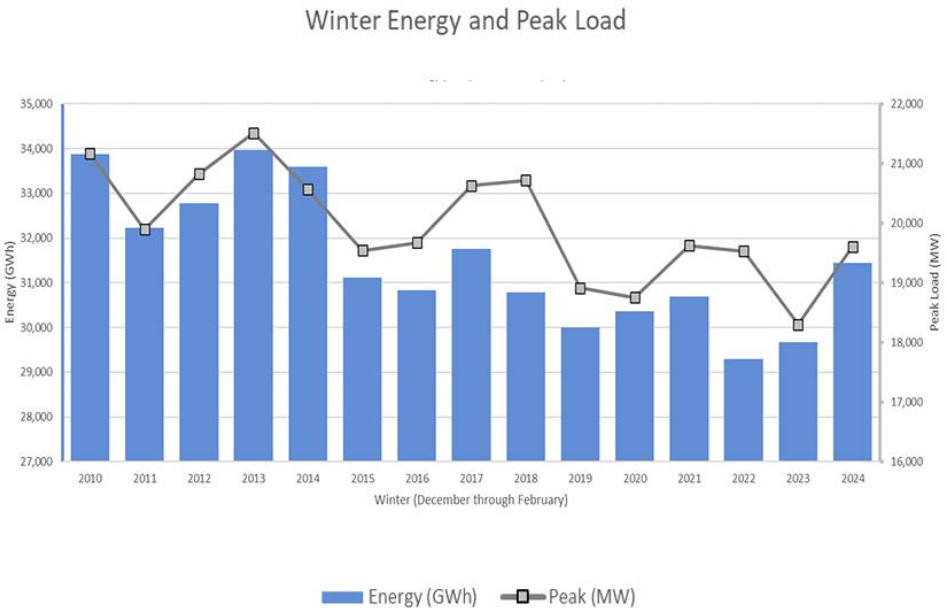
Spot payments for the RTO's Inventoried Energy Program, which compensated thermal resources for maintaining stored fuel on-site, were triggered on five days. The two-year program expired at the end of February.

ISO-NE does not plan to renew the program, which cost about $80 million per winter. The RTO noted in a *memo* in February that "it has not found that the program provided a notable incremental impact on the regions' fuel inventories."

Tariff Uncertainty

ISO-NE also spoke with the committee about the uncertainty surrounding tariffs imposed by President Donald Trump on Canadian imports.

While the RTO has argued that the tariffs should not apply to electricity, it has requested authorization from FERC to collect them in case it is directed to do so by the Trump administration. (See *ISO-NE Braces for Tariffs on Canadian Electricity*.)



ISO-NE winter energy use and peak load, 2010-2024 | *ISO-NE*

ISO-NE and NYISO have retained an outside counsel to engage with the Department of the Treasury and plan to make the case that electricity should not be covered by the tariffs, and if it is, RTOs should not be tasked with collecting the tariffs, a representative of ISO-NE said.

The RTO's understanding is, because the secretary of the Treasury has not issued regulations to bring electricity into the scope of the import tariffs, there is no current tariff on electricity imports, the representative noted. Neither the *executive order* creating the tariffs nor the *notice of implementation* published in the Federal Register on March 6 explicitly reference electricity.

"I think the biggest thing at this stage is that we continue to seek more clarity," ISO-NE spokesperson Matt Kakley said.

Committee Votes

The PC voted to support ISO-NE's compliance proposal for FERC Order 904, which prevents transmission providers from compensating generators for reactive power within the standard power factor range.

In a change from ISO-NE's initial proposal, the RTO will still allow compensation for reactive power outside the standard range. (See *NEPOOL Transmission Committee Briefs: Feb. 27, 2025*.)

The committee also supported changes to ISO-NE's billing policy to account for a recently accepted change to the RTO's financial assurance policy allowing an affiliate company to guarantee the payment of Pay-for-Performance charges. (See *FERC Approves ISO-NE Capacity Market Collateral Requirements*.) ■

National/Federal news from our other channels

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MISO Says Queue Fast Track Design Settled, Ready for FERC

By Amanda Durish Cook

MISO plans to file with FERC by mid-March a proposal to implement a fast-tracked interconnection queue lane for select generation projects.

The grid operator gathered stakeholders for a final workshop March 7 before advancing its proposal to introduce an "expedited resource addition study" in its queue. Its plan would have the RTO processing projects designated as essential by regulators through a separate queue equipped with specialized, dedicated studies instead of the cluster-style studies it uses in the regular queue.

MISO has notified FERC staff of its intention to file. The grid operator hopes to oversee its first applicants at the beginning of June.

"We've heard from FERC staff that it's one of the most talked-about changes in the industry right now," Director of Resource Utilization Andy Witmeier said. He said several in MISO's stakeholder community want the fast track to help resolve imminent resource inadequacy. (See *Generation Developers Ask for Scoring System on MISO Queue Fast Track*.)

A rendering of Entergy Mississippi's plans for its first power plant in 50 years, the 754-MW, $1.2 billion Delta Blues Advanced Power Station. Entergy has already broken ground for the gas plant. | *Entergy Mississippi, Sargent & Lundy*

Witmeier said MISO's current queue is not up to the challenge of processing new projects in a timely manner because of a pileup of study delays. As of Feb. 6, the queue contains about 308 GW across 1,695 projects, according to the RTO.

MISO Executive Director of Resource Adequacy Scott Wright has said the RTO wants to conduct the serial, expedited studies to "fill the gap for a few years" until the normal queue improves so that routine processing of projects can be completed within the span of a year.

But for now, Witmeier said it is important for necessary generation projects to get the benefit of standalone studies that clearly show estimated network upgrade costs without the numerous project dropouts of the regular queue muddying study results.

Witmeier said projects "must be tied to some reliability or RA need" to enter the express lane. Developers submitting applications would need to submit a new *form* and documentation from their applicable regulators demonstrating a project's importance.

MISO would not independently evaluate the need for projects, explaining that would trample on states and load-serving entities' role as resource planners, Witmeier said. "We are not the ones to decide what generation should serve load. We study what reliability impacts occur because of generation additions, load additions," he said.

Projects that take advantage of the express lane would be expected to be in operation no later than 2032. In the first two years of the express lane, projects would enjoy MISO's usual three-year grace period of commercial operation dates beyond its three-year in-service expectation. Projects that enter the fast track in 2027 and 2028, however, would be limited to a single three-year period from developer submission to producing power.

The RTO intends to retire the fast track after a few years.

Why This Matters

MISO said FERC should expect a filing around March 14 to seek permission to use a fast lane in its interconnection queue for select generation projects over the next few years.

Witmeier said the elimination of the additional three-year extension for projects entering in later years tries to recognize the current, frazzled state of the industry's supply chain and the hope that it can be repaired within a few years.

But Wisconsin Public Service Commissioner Marcus Hawkins said he thought the structure could open MISO to "bottlenecks" where developers rush to enter projects.

"It's weird, and it's hard to explain, and it's something I think FERC would find problematic," Hawkins said of the split deadline structure during an Organization of MISO States meeting in late February.

Warren Hess of Central Municipal Power Agency/Services asked how the RTO would ensure it was not overbuilding transmission by maintaining separate queue processes.

"There are multiple parallel processes going on all the time at MISO," Witmeier said, adding that the Business Practices Manuals mandate double-checking the necessity of transmission projects before they are finalized.

"The one, new wrinkle — and it's not new — is you can change the flows and have a new constraint show up," Witmeier explained of the simultaneous queue studies.

He said that while the new process could introduce the "slight chance of over-allocating transmission capacity," MISO is on the lookout for such constraints through its annual transmission planning. ■

MISO Annual Value Proposition Tops $5B for 1st Time

By Amanda Durish Cook

MISO estimates its savings and efficiencies benefited its members to the tune of just over $5 billion in 2024.

It's the first time MISO's annual *Value Proposition* has averaged above $5 billion, though benefits in 2023 came close. (See *MISO Estimates 2023 Member Savings Near $5B*.) MISO said the 2024 range of cost savings is anywhere from $4.52 billion to $5.75 billion. The RTO subtracts membership dues from overall benefit estimates.

The RTO estimates its membership benefits annually through its Value Proposition study, where it attempts to quantify the benefits of its membership against non-RTO entities. MISO does not track cost savings to individual market participants but said members could expect $15 in savings to every dollar spent on MISO membership in 2024.

Per usual, the bulk of the savings (this time anywhere from $2.9 billion to $3.9 billion) is derived from members' access to capacity sharing across MISO's large geographic footprint. Efficiency gains from MISO's energy and ancillary service markets rank second at anywhere from $881 million to $974 million. MISO's ability to optimize the use of members' renewable resources through grid planning again took third place at $403 million to $474 million.

MISO said its reliability category was on average less beneficial in 2024 ($337 million) than it was in 2023 ($346 million) because 2024 held fewer extreme weather conditions.

MISO said the value of its membership is poised to increase over the coming years as the fleet decarbonizes. It estimated cumulative benefits at $50 billion since 2007, when it first began producing the annual approximation.

MISO Carmel, Ind., headquarters | © RTO Insider LLC

In a press release, Senior Vice President and Chief Strategy Officer Andre Porter said members benefit from MISO's "market efficiencies, grid planning and operational enhancements across a large and diverse footprint." ■

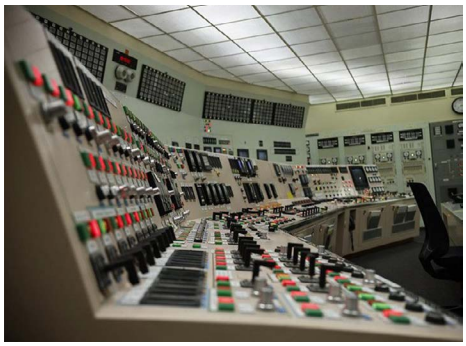
FERC Grants Palisades Extra Time to Get Online

By Amanda Durish Cook

FERC has given the Palisades Nuclear Plant special permission to exceed MISO's 36-month limit on generator suspensions as owner Holtec International works through the plant's reopening.

The commission decided Feb. 28 that Holtec can use a 22-month extension on top of the RTO's three-year limit to bring Palisades back online (*ER25-1083*).

The MISO tariff limits generation suspensions to a cumulative 36-month maximum over a five-year span. After reaching the limit, generators are expected to return to service or risk termination of interconnection service.


The Palisades Nuclear Plant control room around the time Entergy closed it in 2022 | *Entergy*

Holtec told FERC that its plan to return Palisades to service was not crystalized until April 2024. Previous owner Entergy placed Palisades in suspension status with MISO in 2022.

FERC's leeway means Holtec now has until March 1, 2027 — instead of May 20, 2025 — to start the reactor under MISO's rules. Holtec is currently navigating a recommissioning process with the Nuclear Regulatory Commission and hopes to have the plant online in October at the earliest. (See *Anti-nuclear Groups Challenge Palisades Reopening*.)

Holtec argued that if it was not granted the extra time and lost its interconnection rights with MISO member Michigan Electric Transmission Co., it could result in "substantial delays or potential loss of baseload generation critically needed to support resource adequacy in the MISO region."

The Michigan Public Service Commission filed comments in support of the waiver.

Holtec also said it is preparing a new generator interconnection agreement to file with MISO that will lay out expectations and associated deadlines on the path to reactivating the partly decommissioned nuclear plant.

FERC said Holtec seemed to act in good faith and that a continuation of the Palisades suspension without terminating interconnection service would not harm any third parties. On the other hand, the commission said that disconnecting Palisades from the MISO system would "jeopardize the recommissioning timeline." The commission noted that, according to Holtec, Palisades' reopen will not require network upgrades. It also said it had Holtec's word that MISO verified the 22-month waiver would not present "reliability concerns or interconnection queue management issues." ■

Minn. PUC to Amazon: Prove Need for 250 Backup Diesel Generators

By Amanda Durish Cook

Minnesota regulators voted unanimously *Feb. 28* to require that Amazon demonstrate a need for a 250-unit fleet of backup diesel generators at its proposed data center in the central portion of the state.

The Minnesota Public Utilities Commission rejected Amazon's late December petition to sidestep the state's certificate of need process for its planned data center campus in Becker (*CN-24-435*).

During the meeting, Commissioner Joe Sullivan said his mind was "gravitating" toward the plain language of the state statute, which stipulates that any developer of a power plant capable of 50 MW or more must prove the facility is essential over cleaner or more inexpensive alternatives.

Amazon's planned diesel fleet could generate as much as 600 MW. However, attorneys for Amazon and local labor union representatives argued that the generators should sidestep permitting because they would be strictly for emergency backup, not be connected to the grid and not affect ratepayers.

The topic has also reached the Minnesota Legislature, where Republicans are sponsoring a bill to change state law to exempt Amazon from a certificate of need. If passed, the PUC's decision to require Amazon's justification could be moot. The involvement of regulators and legislators demonstrates the uncharted territory of how hundreds of acres of proposed data center should be regulated.

Why This Matters

Minnesota commissioners expressed a desire to hear a rationale for and explore alternatives to Amazon's plan to back up a nearly 350-acre data center with 250 diesel generators. If the state legislature doesn't override the commission, Amazon's explanation would come in a certificate of need proceeding.

Commissioners John Tuma (left) and Joe Sullivan | *Minnesota Public Utilities Commission*

Minnesota Department of Commerce associate counsel AnneMarie Curtin argued that state law is clear in that Amazon's proposed emergency power fleet meets the definition of a large energy facility that requires a certificate of need.

Commissioner John Tuma said the sheer number of diesel generators proposed by Amazon is a "little shocking."

"These are not expected to run more than a few times a year and less than 15 hours a year for the regular testing and maintenance that's required for those systems," argued Christina Brusven, appearing on behalf of Amazon Web Services. She said similar generators are stationed outside hospitals and government centers, albeit on a smaller scale.

Commissioner Hwikwon Ham pointed out that a "huge load" like Amazon's that can drop suddenly from the MISO system can trigger an over-frequency event, especially considering the nearby "sensitive" Monticello Nuclear Generating Plant. He said he wondered whether Amazon's proposed backup would be able to handle such a situation and said he would raise the issue during the certificate of need proceeding.

Tuma said perhaps behind-the-meter generation is not the best way to handle backup power at a site with such large power needs. He urged both Xcel Energy and Amazon to reexamine their ideas about the most appropriate source of emergency power.

"Maybe we can figure out something that benefits both the grid and the system and keeps it safe because, 'This is a large load dropping off' does scare me. These are loads that we are not used to dealing with. … This is something that's new, and we need to understand what it means for the security of the system," Tuma said. He urged Xcel to prepare answers on how the load could reliably trip offline and "meaningful alternatives" to the diesel fleet.

"I keep hearing from these Amazons and all these [companies] that they want to do the right thing, and they want clean energy, and that's why they want to plop their data center right next to that solar facility, so I want to hear that those discussions have happened," Tuma said.

Commission Chair Katie Sieben asked why Amazon did not simply file a certificate of need with its site permitting materials and then lobby for the bill in the legislature. She said it is "frustrating" that Amazon continues to "squeeze" the commission over ambiguous language in state law. She suggested that Amazon might sue the commission if the law is passed.

Brusven said it's not Amazon's goal to put the commission in a "difficult position."

"It is. You did," Sieben responded and suggested that Amazon could have been "farther along" in the permitting process at this point had it already opted to explain its need.

Sieben said she expected interested parties in the forthcoming certificate of need process to push Amazon for more environmentally friendly options like biodiesel. ■

Moody's Forecasts Long-term Population Downturn in NY

Electrification of Buildings and Vehicles to Continue to Push Demand up

By Vincent Gabrielle

NYISO on March 4 presented its assumptions for the *economic* and electrification trends that would drive load growth through 2040s based on Moody's Analytics data, which show statewide population to "significantly" decline, dropping below 18 million by 2055.

The steepest areas of decline are western and central New York, Max Schuler, demand forecasting analyst for NYISO, told the joint meeting of the Load Forecasting Task Force and Transmission Planning Advisory Subcommittee. The state's population as of the 2020 U.S. Census was 20.2 million.

Household growth is projected to be flat through the end of the decade, then begin to decline along with the population throughout the 2030s and 2040s. Total employment is expected to increase during 2025 but decline in the long run. Gross state product has recovered from the COVID-19 pandemic and is expected to be strong in the long term.

Despite the drop in population, NYISO expects electricity demand to continue to grow, in part from electric vehicle *adoption* and *building electrification*. The ISO's baseline assumption is that 80% of new vehicle sales will be those of electric models by 2035.

A stakeholder asked whether these scenarios had been developed with the recent presidential election in mind.

"These scenarios were more pre-election and so probably won't account for new changes in policies recently," said Ebby Thomas, NYISO demand planning analyst. "The rates are based on the data we do have."

Thomas went on to explain that even if the overall stock of vehicles declines because of population loss, there would still be millions of new vehicles coming onto the grid. The growth curve becomes exponential during the "stagnant" population decades of the 30s and 40s. By 2040, NYISO projects that there will be about 6 million electric vehicles on the grid consuming 30 TWh of electricity.

Building electrification is also projected to grow through a variety of technological changes, including air source, ground geothermal, electric resistance and dual-fuel heat pumps.

"In 2024, Moody's tells us there's 7.7 million households throughout the state. By 2040 that drops to 7.6 million," said Arthur Maniaci, principal forecaster for NYISO.

By 2030, New York would be "close" to the Public Service Commission's targets for electrification in each utility's footprint, a little under 250,000 homes statewide. By 2040, 22% of housing units will have adopted some form of electric heating technology, the ISO predicts. If adoption occurs at that rate, NYISO projects that the state will be using 4,000 GWh annually for electric home heating in 2040. By 2050, 75% of all homes would be electrified.

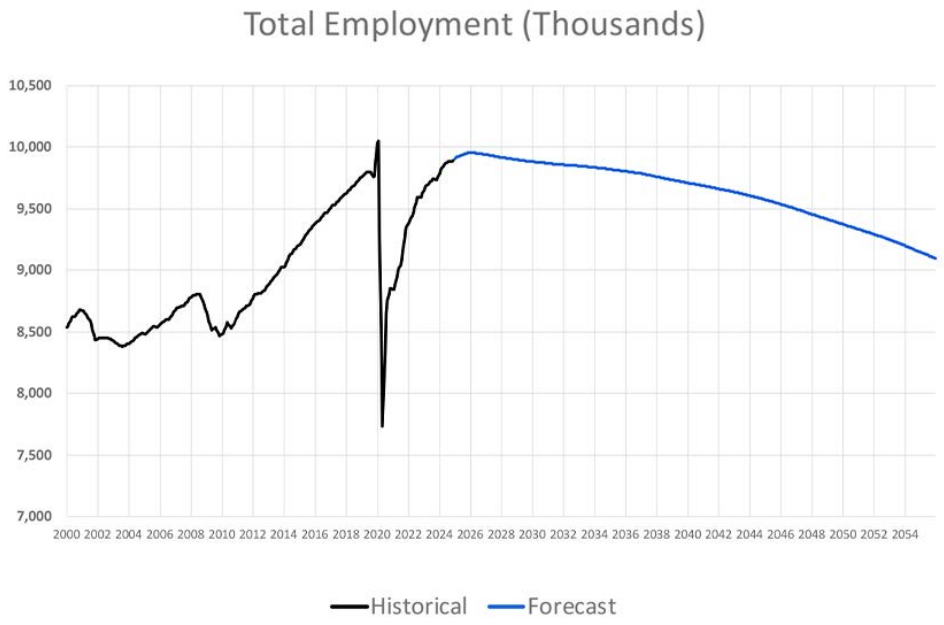
The forecast for heat pumps includes different adoption rates in different regions. NYISO does not anticipate high rates of ground geothermal heat pump adoption in New York City, for example, instead projecting that such systems will be more popular upstate.

Some stakeholders questioned the rates of replacement NYISO put forward.

"You're talking about a major expense for something that otherwise one wouldn't do," said Mark Younger of Hudson Energy Economics. "The [New York State Energy Research and Development Authority] incentives are borderline insignificant in the face of the expense."

After some back and forth, Maniaci said it was possible that NYSERDA could open up the incentives "like they did for solar" to enhance adoption rates statewide. He said these incentives had been enormously influential in getting solar onto residential roofs.

"What we are trying to do is give our best effort at incorporating emerging technologies consistent with state energy policies," Maniaci said. "Everyone knows that the [Climate Leadership and Community Protection Act] has some aggressive goals. This forecast is making our level best effort at incorporating those." ■



NYISO

NYISO Stakeholders Debate Purpose of Capacity Market

ICAPWG Considers Further Seasonal Divisions in Market

By Vincent Gabrielle

NYISO and its stakeholders continued their *review* of the capacity market's structure March 3 with at-times philosophical debate on the market's purpose in New York, with some arguing that state policy has played an outsized role in new resource entry.

The ISO opened the meeting of the Installed Capacity Working Group with a statement summarizing its position on that purpose, which had been requested by stakeholders: to accurately value resources according to how they contribute to system reliability, provide nondiscriminatory price signals and function without unnecessary administrative complexity, among other ideals and goals.

Staff also summarized stakeholders' proposed changes to the market so far:

- incorporating additional revenue streams and resource attributes into the demand curve reset (DCR) process;
- shifting the DCR anchor from cost of new entry to "forward going cost" of existing resources;
- bifurcating the capacity market into new and existing resources;
- developing an "attribute-based" market, which could include resource adequacy, transmission security or environmental attributes;
- increasing the seasonality of the capacity market, valuing capacity where it is needed more during the peak months;
- enhancing the zonal elements of the capacity markets;
- refocusing the capacity market to ensure price stability regardless of public policy shifts.

NYISO noted the arguments for and against each proposal in its presentation; it intends to present the group with its recommended list of items to remove from further consideration March 17 and prioritized list of changes to consider March 26.

Much of the debate between stakeholders centered on the role of state policy and how to factor that into the market, if at all.

NYISO headquarters in Rensselaer, N.Y. | *NYISO*

"It is the TOs' position that we need to critically evaluate the degree to which the market is the driver for new entry *versus* state policy," said Stuart Caplan, representing New York Transmission Owners. "Over the last four-plus capability years, all the new entry has been public policy resources."

Caplan said that NYISO and the stakeholders needed to accurately consider how the market was actually functioning; otherwise the process would generate a solution that was "inappropriate" and "not produce just and reasonable results." The base assumption of what the capacity market is for, and the context in which it functions, should be analyzed as part of the review, Caplan argued.

Doreen Saia, chair of Greenberg Traurig's energy and natural resources practice in Albany, said that Caplan had turned the problem on its head.

"Either we are going to have a state policy for every kind of resource we could add to the system, or we need to think about designing the new structure so we can keep open the ability of the market to choose resources and place them," she said.

Caplan replied by saying he was just describing things as they are and that failure to accommodate those facts could produce unjust results.

"If the primary driver remains state policy, state solicitation and contracts, then all you have is a massive wealth transfer from consumers to existing, primarily fossil fuel, generators," Caplan said. "And the price signal would not be the driver of new entry."

Matt Schwall, director of regulatory affairs for Alpha Generation and chair of the meeting, said that he had seen roughly 2 GW of investment that had been attracted to the competitive market.

"I compare that to the amount of megawatts that have been built in the wholesale market as a result of state policies, and I don't know that one is greater than the other," Schwall said. "I think to the extent that the markets can't continue to attract investment and resources the state wants, it's because we've been chipping away at the fundamentals of competitive market design."

Caplan said that this was missing his point, "like two ships passing in the night." He said that the situation that New York faced — high capacity prices without new resource entry — creates a problem where there is no mechanism to create competitive prices. This needed to be reckoned with during the market redesign process.

Saia said that there had been numerous studies indicating that the renewables the state wants added to the grid do not provide the reliability the system has "gotten used to," so the market would need to compensate extant fossil fuel generation for some period. She pointed to the evolution of technology in both fossil fuel and energy storage.

"We have some very difficult decisions. I have not a doubt that some of this is going to be complicated," Saia said. "We may need to, rather than change the demand curve reset process, add some kind of provision for a transmission security mechanism … so that we can manage that dispatch ability that we're looking for."

One stakeholder said that a key element of the discussion was whether the market should accommodate state policies, or if state policies should accommodate the market. He said at this point in the process, stakeholders and the ISO should take the opportunity to look at things holistically, rather than assume whether state policy or markets should come first.

A different stakeholder spoke in favor of using the capacity market to help value non-emitting resources for reliability.

"To ignore zero carbon in the capacity market and to not identify a separate product that brings us reliable capacity is, in my view, a mistake," they said. "It's holding on to Old World views of the capacity market and what the policy is."

Another stakeholder representing Shell disagreed, saying that introducing an integrated resource planning mechanism into the capacity market would dull the market's ability to reward reliability attributes.

Seasonal Capacity Accreditation Proposal

Starting this May, NYISO will implement different capacity demand curves for summer and winter to represent the differences in risk for each capability period.

Mark Younger of Hudson Energy Economics proposed a way *to take this further*, breaking out both the peak and shoulder months from the season. Under this structure, the market would compensate capacity at 180% of the seasonal ICAP value during peak months and 20% during the shoulder months.

Younger clarified that the specific multipliers were just examples and should be reviewed to make sure that they promoted the right behavior from resources. Under his example, November, March and April would be considered the winter shoulder months, while May and October would be the shoulder months for the summer. June and September would be paid the baseline summer price.

"I've identified an issue that has not been explicitly part of the ISO's focus that I think should be, and should be included in their winter reliability project," Younger said. "What I'm focusing on is that the reliability needs are not the same in each month of a capability period."

Younger said this was critical now because there are resources for which the capacity is purchased in the winter's shoulder months but not during the peak months. Now that the ISO was becoming more concerned about winter reliability risks, Younger said it made no sense to pay those resources more for contributing when they are less valuable and not contributing when they are more valuable.

He cited Hydro-Quebec specifically and said it was unlikely to behave differently after the Champlain Hudson Power Express is built.

"That's my fear: They have nothing in their contract; they have no credit for capacity in the winter months," Younger said. "They can sell capacity in the winter months, but that's outside of contract."

Several stakeholders said this seemed like a logical extension of where NYISO was already heading. Zachary Smith, senior manager of capacity and new resource integration, said the ISO was considering Younger's proposal and how it would impact things like collateral requirements for small loads. ■

Parties Point to Each Other's Policies as Drags on Meeting Demand Growth

By James Downing

The House Energy and Commerce Subcommittee on Energy held a hearing March 5 to discuss meeting the growing demand for power, with each party's members claiming the other side's policies were hindrances.

Data centers, industrial shoring and other factors are driving up demand now as thermal generation is retiring, subcommittee Chair Bob Latta (R-Ohio) said.

"Meanwhile, subsidized intermittent energy resources and public policy decisions in favor of renewable energy are flooding interconnection queues and making baseload power from coal, natural gas and nuclear near uneconomic," Latta said. "Generation developers continue experiencing ongoing supply chains constraints for distribution transformers and generation turbines."

The ranking member of the subcommittee, Rep. Kathy Castor (D-Fla.), pointed to recent disruptions in the federal bureaucracy.

"It's rather absurd that we're tackling strengthening our electrical system while Elon Musk and the Trump administration are taking a sledgehammer to the Department of Energy, and especially the initiatives that strengthen and modernize the grid," Castor said. "The new administration has spent weeks illegally shutting down DOE grants and loans and partnerships that make energy safe, reliable and affordable."

The administration's tariffs on the country's largest trading partners are making key grid and generation components more expensive, in addition to the higher power prices already being felt especially in northern states, she added.

While members took shots at their political opponents, both Latta and Rep. Frank Pallone (D-N.J.), ranking member of the full committee, said the growing demand was an opportunity to seize economic growth and keep the U.S. as the leader in artificial intelligence.

"It means that companies are investing in America," Pallone said. "The cutting-edge technologies are being developed here, and the families are making investments of decarbonizing their homes and vehicles. These are good things."

Basin Electric Power Cooperative CEO Todd Brickhouse said the co-op is experiencing some of the same rapid load growth as other parts of the country. It serves 3 million customers living across 12% of the U.S.' territory in nine states.

"Basin is currently increasing its generation portfolio by more than 40%, and we are increasing our transmission mileage by more than 20% over the next decade; we will spend $12 billion on these endeavors," Brickhouse said. "That compares to currently $8.5 billion of assets on our balance sheet today."

From left: Basin Electric CEO Todd Brickhouse, PJM Senior Vice President Asim Haque, Duke University Senior Fellow Tyler Norris and Southern Co. Senior Vice President Noel Black testify at the House Energy and Commerce Subcommittee on Energy on March 5. | *House Committee on Energy and Commerce*

Why This Matters

With data centers and reshoring manufacturing being bipartisan policy goals, helping the industry meet the new demand for power from both could produce some policy changes this Congress.

Improvements in federal permitting would help get that work done, with Brickhouse recounting how one transmission project required two different assessments from different bureaus under the Department of the Interior. Basin is also adding 1,500 MW of new renewable resources to help meet that load growth.

"This has required years of planning and development work, and these business decisions were made based on the availability of production tax credits [PTCs]," Brickhouse said. "We understand and we support the need to put our country on a sustainable physical path, but the immediate removal of PTCs will not allow utilities to plan for and avoid increased costs, and this will also immediately harm ratepayers."

The tariffs will also make that $12 billion of overall expenditure more costly for ratepayers as Basin recovers the funds from ratepayers over the next several decades, Brickhouse added.

PJM is seeing load growth driven by new data centers and manufacturing, said Senior Vice President for Governmental and Member Services Asim Haque.

"PJM expects its summer peak to climb to 220,000 MW over the next 15 years," Haque said. "To compare, our all-time summer peak, which occurred in 2006, is 165,563 MW."

For years, PJM had a healthy reserve margin, but the load growth and some retirements are eating into that now, with

the tighter supply-and-demand balance leading to higher capacity prices. With interconnection queue and capacity market reforms in recent years, the RTO has almost caught up with its queue backlog and is about to implement its new system, Haque said.

"We want as much supply as we can get in order to meet this growing demand, whether that's delaying retirements, new supply, that supply in our queue and even additional supply on top of that," Haque said.

PJM has cleared 50 GW of primarily renewable resources through its queue, which are having challenges related to financing, the supply chain, and state and federal siting processes. Repealing the Inflation Reduction Act and its tax credits for renewables would add financial strains to those projects, Haque said.

One way the customers behind the new demand could help the situation is by ensuring that they can offer some flexibility to the grid, said Tyler Norris, a James B. Duke fellow at Duke University.

The average use rate for the grid is just 53%, meaning that almost half of generation is sitting idle at most times, said Norris, the lead author on a recent study on data center load flexibility. (See *US Grid has Flexible 'Headroom' for Data Center Demand Growth*.)

"Our analysis finds that with modest flexibility from new large loads, the grid can accommodate significant demand growth without major new infrastructure," Norris said. "The U.S. power system is already designed to handle extreme peaks and demand, meaning that in most hours, a substantial portion of the power system is unutilized. …

"Flexible load strategies can provide a bridge, while long-lead resources such as new transmission and clean firm generation are developed."

Noel Black, Southern Co. senior vice president of regulatory affairs, argued his firm's vertically integrated, traditionally regulated model has prepared the region it serves well for the new load growth, in part by completing the new nuclear reactors at Plant Vogtle.

"Straightforward regulatory models like ours, where the accountability for the grid is clearly understood, are producing results enabling this innovation economy," Black said. "In short, the Southeast remains open for business. Regions with unusually complex regulatory processes are experiencing slower infrastructure build out. I think this may be why the concept of co-location has become so popular in certain parts of the country."

Co-location is a major issue in PJM, where Haque said the RTO would have more to say in 30 or 60 days, as it is currently working to implement a recent FERC order. (See *FERC Launches Rulemaking on Thorny Issues Involving Data Center Co-location*.)

The Electric Power Supply Association, which represents independent power producers active in markets and some of which are pursuing co-location deals, released a statement on the hearing arguing that organized markets were poised to meet the growing demand.

"Appropriately structured competitive wholesale markets can drive innovation and competition and ensure that ratepayers are not exposed to any unnecessary or inefficient investment," EPSA CEO Todd Snitchler said. "Given the uncertainty surrounding how fast demand will grow in the coming decades, it is critical that investment risk be borne by developers and not shouldered by ratepayers." ■

PJM Stakeholders Approve SIS Manual Language

By Devin Leith-Yessian

VALLEY FORGE, Pa. — The PJM Planning Committee on March 4 endorsed by acclamation *revisions* to Manual 14H to conform with changes to the RTO's surplus interconnection service (SIS) process FERC approved in February (*ER25-778*).

The committee discussed the specifics of how PJM would implement the changes during its meeting before approving the language. (See *FERC Approves PJM's One-time Fast-track Interconnection Process*.)

SIS allows developers to add new resources to an existing point of interconnection that is not fully used; for example, if an existing resource does not operate at all times of day. Injection is capped at the capacity interconnection rights in the original resource's interconnection service agreement, and surplus interconnection requests do not trigger the need for new network upgrades.

The new manual language would eliminate categorical prohibition on storage eligibility for SIS; change how PJM models proposed resources alongside projects in the generation interconnection queue; expand eligibility to allow SIS applications when the host resource is still in development; and allow projects that consume transmission headroom but do not require network upgrades. It would also allow projects that require additional interconnection facilities for the service while still prohibiting new network upgrades.

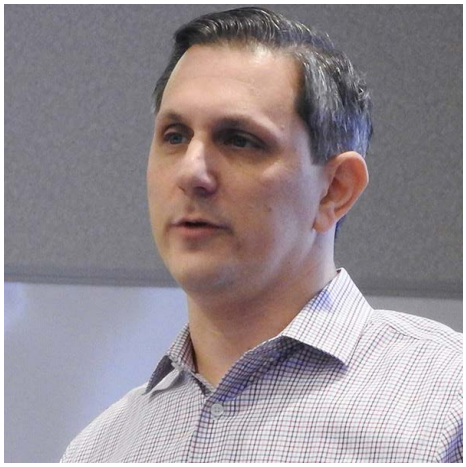
PJM's Ed Franks said SIS applications would be studied using the most recent cluster phase 3 model to be commenced, which he said would strike a balance that allows projects to proceed without being disrupted if others in that cluster drop out. Franks said it is less likely for projects later in the queue to withdraw, reducing the risk of cluster analyses having to be retooled in a manner that impacts the potential for SIS projects to be assigned network upgrades.

"This would only be exponentially more complicated if we were using an earlier model," he said.

Responding to stakeholder questions on what battery storage configurations would be allowable, Franks said both open- and closed-loop storage would be permitted so long as network upgrades are not triggered.

Ken Foladare, director of RTO and regulatory affairs for Tangibl Group, said the change would allow existing renewable resources to increase their reliability contribution by adding storage, transforming a non-dispatchable resource into semi-dispatchable.

"This is a good opportunity for PJM to be able to add megawatts, especially if you're adding battery storage to standalone wind, standalone storage and contribute to resource adequacy," he said.



Jason Connell, PJM | © RTO Insider LLC

Stakeholders questioned whether there would be a cure process for cases in which network upgrades are identified and allow for developers to change the scope of their projects to mitigate those violations. PJM Vice President of Planning Jason Connell said the tariff is clear in that if the SIS request causes a need for network upgrades, it would be denied.

PJM Director of Interconnection Planning Donnie Bielak said developers could submit a new application with changes that could avoid triggering the upgrades that led to rejection. He said the RTO wants to avoid taking on the role of a design consultant engaging with a back-and-forth with the developer on what can be done to avoid network upgrades. ■

Donnie Bielak, PJM | © RTO Insider LLC

Why This Matters

Expanding eligibility for surplus interconnection service (SIS) is one of several changes to PJM's capacity market and interconnection rules that FERC has approved in an effort to speed the development of capacity resources as the RTO warns that a shortfall is possible in the 2029/30 delivery year.

NJ Conference Confronts Electricity Demand Squeeze

Speakers Say Dramatic Action Needed to Meet Demand Surge in State

By Hugh R. Morley

GLASSBORO, N.J. — Facing a projected 40% hike in regional electricity demand by 2030, New Jersey needs to rapidly craft a plan on how to boost generation and develop its transmission and distribution system, according to speakers at a Feb. 27 conference on the state's energy future.

Power demand from data centers and artificial intelligence projects, along with the expected increase in electric vehicle use and building electrification, are driving demand forecasts that project a power shortfall without significant action, industry stakeholders and state officials said at Meeting New Jersey's Energy Needs, held at and hosted by Rowan University's Steve Sweeney Center for Public Policy.

The most visible sign of the shortfall was the Basic Generation Service auction held by the New Jersey Board of Public Utilities in February, which will trigger a hike of about 20% in the average residential bill in June.

New Jersey BPU President Christine Guhl-Sadovy | *© RTO Insider LLC*

"It's a supply-and-demand issue … We need more electrons on the grid," BPU President Christine Guhl-Sadovy told the conference of about 150 energy executives, government officials and other stakeholders. She added that it is "unrealistic to think that this kind of price shock can be absorbed by ratepayers without impact."

Yet it is not clear in the current, uncertain political and energy environments where the additional supply to New Jersey, an energy importer, will come from, speakers said. The stalling of the state's offshore wind projects, and the lack of clarity over the future economics of solar and other forms of renewable energy generation in the face of opposition to subsidies from the Trump administration, could upend the state's expected reliance on those sources, speakers said. (See *NJ Abandons 4th OSW Solicitation*.)

From left: Lawrence Barth, NJR Clean Energy Ventures; SJI CEO Michael J. Renna; Asim Haque, PJM; and former BPU Commissioner Bob Gordon | *© RTO Insider LLC*

"All these trends are evident in New Jersey," former state Sen. Bob Gordon, a former BPU commissioner, said as he introduced a panel of generation company executives. "And we're starting to see some real impacts of the supply-demand imbalance."

The disruptions are unfolding amid ongoing warnings by PJM that aging fossil fuel plants are going offline at a faster rate than replacement plants are arriving, and the RTO is struggling to maintain a generation balance.

"The supply-demand crunch has come to us quickly," said Asim Haque, senior vice president for PJM, who underscored the urgency of the situation by noting that the RTO saw its highest ever winter peak demand this year on Jan. 20, Martin Luther King Jr. Day.

In assessing how to boost generation, states need to understand that different generators have different "capabilities of how they can contribute to reliability on the system," he said.

The suddenly oncoming demand suggests the state should move cautiously in its rush toward electrification, said Michael J. Renna, CEO of South Jersey Industries, which owns several natural gas distribution utilities in the state.

New Jersey's heating-fueled winter peak is three times as high as the air-conditioning-driven summer peak, and "the grid, including all the way down to the utility levels, is built for the summer peak," Renna said.

"You rush to electrification, you've got big problems, because neither the grid nor the utility systems are capable of moving that much electricity, let alone the fact that we have a generation cap," he said.

He suggested the state instead focus on decarbonization by using gas with lower carbon content that can be used on existing infrastructure, such as "renewable natural gas or green hydrogen that can safely be blended with the geologic natural gas."

Tim Sullivan, CEO of the New Jersey Economic Development Authority, which funded much of the state's offshore wind initiatives, said he continues to believe that the economic and employment benefits of wind generation, and the escalating pressure to add supply sources, will return wind to the fore.

"We are not giving up on wind," he said. "One of the reasons I'm confident in that is that we actually are seeing, outside of Jersey, progress in offshore wind projects. You've got electrons that are flowing in Virginia, New York and Massa-

chusetts that are hitting their grids.

"It's very hard to disabuse me of the notion that the best way forward for New Jersey" is to address the supply-demand imbalance with offshore wind, he said.

Nor is the state going to shy from the energy challenge presented by the demands of AI projects, Sullivan said.

"AI across the country, across the globe, is going to be an energy monster," he said. He acknowledged that AI projects need "hundreds of megawatts to a gigawatt of power, and they need hundreds of acres of space," both of which are limited in New Jersey.

Nevertheless, Gov. Phil Murphy is "smartly positioning the state to be a leader, not a follower, in AI," Sullivan said. He noted that the state recently launched a program that will award $500 million in tax credits to support AI infrastructure and cited the example of a $1.2 billion state-of-the-art data center planned by CoreWeave. The company *signed a lease* in October on 280,000 square feet of space at the former global headquarters of pharmaceutical giant Merck in North Jersey.

Harnessing Existing Infrastructure

Hanging over any solution that helps boost generation is how to overcome the challenging task of connecting a project to the state's transmission and distribution system, speakers said. That includes the well known delays with PJM's generator interconnection queues.

In addition, all of the state's four utilities, to varying degrees, have areas where projects cannot be connected because the infrastructure cannot accept them, said Lyle Rawlings, president of the Mid-Atlantic Solar & Storage Industries Association (MSSIA).

"That's the big bad problem that we're facing. It's already putting tremendous downward pressure on our ability to deliver solar in this state," he said.

The issue was a major factor in the drop in installed solar capacity in 2024, he said. BPU figures show installations were 40% below the 2023 level even as the state reached a milestone of 5 GW of installed projects.

Still, Rawlings said, the state is "on track" to reach its goal of 17 GW of installed solar power by 2035, and MSSIA modeling shows that by then it could account for 24.5% of New Jersey's electricity, with nuclear contributing 34%. (See *Struggling NJ Solar Sector Evaluates Net-metering Reform*.)

Former Commissioner Gordon suggested that part of supply could be swiftly increased by connecting grid-scale battery storage through the infrastructure left behind by now closed generating facilities.

"The task of getting the PJM approval for a battery storage facility located at an old fossil fuel generating plant could take much less time than a brand new project," he said. "I mean, maybe 90% of the analysis has already been done, and you're not likely to encounter the political pushback from building something new in an area that might affect the neighbors, because people been living with this generating plant for decades."

PJM's Haque said the RTO is awaiting the result of an application to FERC to grant approval in such a situation. He said PJM also has sought permission to grant accelerated approval to projects that pair a generating facility that already has been approved with a battery storage project.

"It's about trying to expedite resources," he said. So an approved solar project could be paired with storage, enabling the batteries to "produce during periods where that solar unit can't produce" and without forcing the storage operator to "go through the queue."

Leveraging the Footprint

A similar strategy of harnessing "surplus interconnection opportunity" could be adopted by upgrading the state's existing solar projects, said Lawrence Barth, director of corporate strategy at NJR Clean Energy Ventures, an energy project developer and operator.

"We ought to be thinking about how do we leverage that footprint now that we've got panels that produce two to three times that amount than when they were originally installed, at lower cost," he said.

Several speakers suggested the state consider boosting generation by adding to the nuclear fleet in South Jersey, the Salem 1 and 2 plants and Hope Creek, which are operated by Public Service Enterprise Group and generate about 40% of the state's electricity. They cited the example of Plant Vogtle — one of the *first nuclear reactors built in the U.S. in nearly in a decade* — that came online in Atlanta in 2024.

But they also noted the extensive permitting bureaucracy, massive investment and lengthy construction timeline needed; Vogtle took 15 years to build. More feasible would be a small nuclear reactor, which could be built in five or six years, said Erick Ford, president of the New Jersey Energy Coalition.

"If they're going to start the process now, [by] 2030 they should be able to have it online," he said. ■

Sam Salustro, Oceantic Network (left), and MSSIA CEO Lyle Rawlings | © RTO Insider LLC

PJM Stakeholders Endorse Changes to Black Start Compensation

By Devin Leith-Yessian

The Market Implementation Committee endorsed a PJM *proposal* to revise the base formula rate for compensating black start resources, receiving 95% support. A competing proposal from the Independent Market Monitor received 11% support. (See "First Read on Black Start Compensation Proposals," *PJM MIC Briefs: Feb. 5, 2025*.)

The proposal would replace a central component of the formula — the zonal net cost of new entry (CONE) — with a five-year average of the RTO-wide net CONE for the 2025/26 delivery year, which thereafter would be updated annually using the Handy-Whitman index. The changes were proposed in response to the possibility that high projected energy and ancillary service (EAS) revenues could depress regional net CONE values, causing black start revenues to also fall.

PJM's Glen Boyle said the proposal also would break the tie between the capacity market and black start revenues, which he said would reduce volatility for black start providers and load.

"If we do nothing under the status quo, we would see the black start revenue drop significantly from where they currently are," he said.

Glen Boyle, PJM | © RTO Insider LLC

Monitor Joe Bowring said the impetus for PJM's proposal already has been resolved with FERC's approval of a request the RTO made to shift the reference resource from a combined cycle (CC) generator to a gas turbine (CT). PJM argued the reference resource change was necessary as the higher EAS revenues for CC units were a major contributor to the drop in net CONE. He said there is no immediate problem and establishing cost recovery payments based on anecdotes rather than evidence is not the way to go. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

He said the Monitor's data showed the exact levels of payment under the current net CONE approach, which does not support the need for a change in the approach.

"The facts do not support the assertion that black start revenue would drop significantly. In response to the goal that all black start providers receive the same payment," he said.

The Monitor's package would use the RTO-wide net CONE, rather than the five-year average, with Bowring calling for stakeholders to continue their discussions on black start compensation to pursue a solution that identifies the best way of defining the cost of providing black start service and compensate for that with a reasonable profit.

Bowring said PJM has not defined a metric that defines adequate compensation.

"Absent a metric based on the cost of providing the service, there is no way to objectively evaluate the need for different compensation. PJM's assertions are not based on any actual evidence. The failure to propose a metric and the assertion that a metric cannot be created are an indication that PJM is not thinking about the issue clearly. PJM's arguments could have supported any level of increase in payments," he said.

Exelon's Alex Stern said PJM has held numerous requests for proposals (RFPs) for additional black start capability that have gone unanswered. Failing to reconsider how resources are compensated could put the reliability of the grid in jeopardy, he said.

Why This Matters

PJM stakeholders and the independent market monitor disagree about whether there is evidence black start resources are leaving because they're not being adequately compensated.

"We're seeing an elevated risk with respect to black start, and we're most definitely seeing black start resources exiting providing the service, and it's concerning."

Boyle said even with the change in reference resource, net CONE values still will fall in the 2025/26 delivery year and PJM has heard concerns that lower black start revenues could fail to cover the costs generation owners incur providing the service.

"We want to fix the immediate problem, but we would certainly be interested in further discussion down the road," he said.

Bowring said there's no evidence black start resources are leaving because they're not being adequately compensated. He said the Monitor's proposal is to look at the issue rationally and make sure revenues are enough to provide the service.

"The only way to determine whether the payments are covering the costs of providing black start service is to take a detailed look at the costs. PJM has resisted that proposal," Bowring said.

Boyle said he's unsure what kind of metric PJM could produce to demonstrate whether generation owners are likely to participate in black start RFPs, adding that the RTO has been canvassing market participants. He also said the proposal would not increase compensation over current levels, which PJM feels are appropriate. ■

PJM OC Briefs

PJM Presents Detail to Synchronized Reserve Requirement Changes

VALLEY FORGE, Pa. — PJM Senior Dispatch Manager Kevin Hatch presented more detail on the RTO's plan to scale back a 30% adder it added on the synchronized and primary reserve requirement in May 2023. (See "Stakeholders Discuss Synchronized Reserves," *PJM MRC/MC Briefs: Feb. 20, 2025*.)

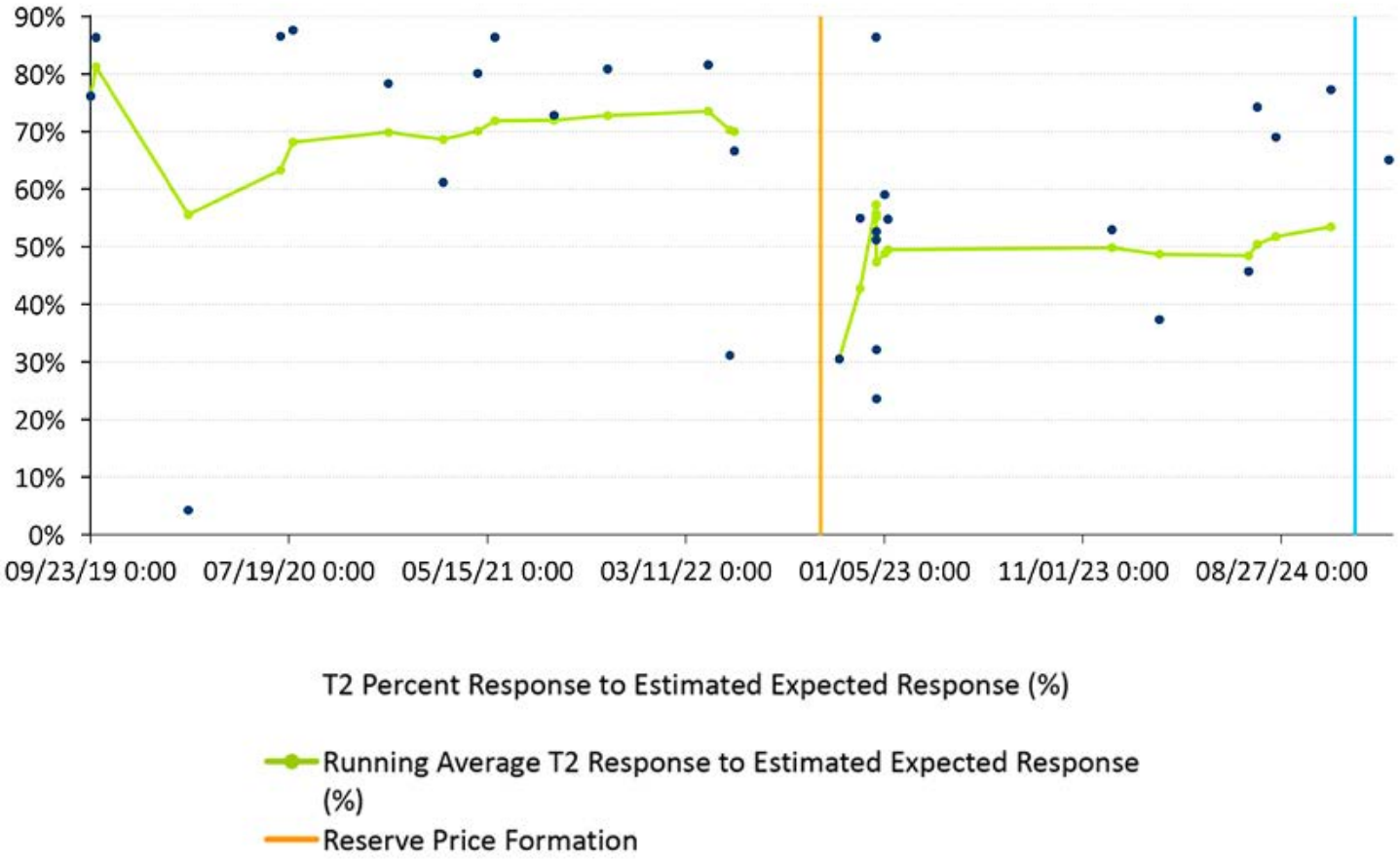
The adder would be scaled back incrementally if average reserve performance increases across three consecutive events. If performance is above 75% for three events, the adder would be reduced to 20%; if performance increases to 85%, the adder would be set at 10%; and if performance gets above 95%, the adder would be removed. The plan also includes a fallback if average performance across three consecutive events declines below 75%, in which case the adder would increase by 10%.

The adder would be capped between 0 and 30%, meaning that the reserve requirement could not fall below 100% of its tariff-defined value nor increase above 130%. Once the adder has been changed in either direction, the three-consecutive-event counter would be reset. Only events exceeding 10 minutes would count toward the average.

Hatch said PJM's hope is that the implementation of changes to automatic generator control (AGC) for reserve resources in December 2024 will improve the ability for generation owners to understand when and how they are being deployed. It updates resources' basepoints with reserve instructions and allows for units to be deployed at less than their full output. (See "Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility," *PJM MRC Briefs: July 24, 2024*.)

Hatch said PJM went with the 10-minute threshold because that is the amount of time synchronized and primary reserves are expected to perform for.

Hatch said the AGC proposal was the first step in the right direction and PJM is open to making further changes to make sure there are adequate incentives for units to respond. While PJM wants to start backing off the requirement increase, it has to be performance driven.



A PJM graphic shows how the average synchronized reserve performance during recent events. | *PJM*

Stakeholders Resume Discussions on SATA

Stakeholders resumed talks on a *proposal* to define rules for storage as a transmission asset (SATA) years after the Markets and Reliability Committee (MRC) deferred voting on the package.

The proposal was endorsed by the PC in December 2020, but the MRC delayed action the following February until after rules governing how storage acts in PJM's markets had been developed. PJM brought a *problem statement* and *issue charge* before the PC to reopen the subject in September 2024. The committee delayed action in October due to the number of pressing issues before stakeholders. The motion to defer precluded action on the issue charge before February 2024 and called for education to be conducted first at the OC. (See "Vote on Issue Charge to Establish SATA Rules Deferred," *PJM MRC Briefs: Oct. 30, 2024*.)

PJM's Jeff Goldberg said there would be several distinctions between SATA and other transmission assets, including downtime during charging periods limiting its ability to resolve some types of violations.

To maintain RTO independence, SATA owners would be responsible for maintaining state of charge on single- or multi-peak days by submitting schedules for charging and discharging times. The batteries would need to be configured in an automatic operation to allow them to respond instantly to frequency or local load security needs. Installations would not be able to be moved between sites under normal operations. Any change in location would require a new baseline reliability study.

Granular load curves would be used to determine how much storage must be in place to resolve a violation; if those curves were not available, then four hours of storage of sufficient scale would be required.

The proposal would apply only to storage acting solely as transmission, with the possibility for dual use between transmission and markets put off to possible future discussions if transmission rules are finalized. Goldberg said dual use being the third phase of storage rules, following markets and transmission, was PJM's intent when the SATA rules were first drafted, and that remains the possible road map. But a key consideration is that batteries would need to retain enough charge to resolve transmission needs while also participating in the markets.

Several stakeholders questioned how PJM would determine when to deploy SATA assets to resolve a transmission need instead of dispatching market-based resources.

PJM Director of Transmission Planning Sami Abdulsalam said operators would have to monitor and take SATA deployment into account. It would be used for reliability and not arbitrage to play in the market. Director of Stakeholder Affairs Dave Anders said that will be part of the education and subsequent package development, adding that some areas of the proposal developed in 2020 may need revisiting.

Exelon Director of RTO Relations and Strategy Alex Stern said the reliability issues PJM is experiencing have grown since SATA last was discussed and states increasingly have pushed for its deployment. When the package was drafted, the intention was to allow PJM and TOs to evaluate if SATA could be used as a solution to both regional and local transmission needs; the challenge for stakeholders is how to do that in a way that isn't making storage a market asset while allowing it to participate on the transmission side. If that cannot be accomplished, there should be a record created to explain the barriers to member states.

February Operating Metrics

Presenting monthly operating *metrics*, PJM's Joe Mulhern said the RTO saw three days in February where load forecast error exceeded staff's 3% benchmark, mainly due to unexpected weather conditions. The overall hourly error rate was 1.81%.

The peak for Feb. 2 was 4.04% under forecast due to a storm that brought unexpectedly cold temperatures and snow, increasing load throughout the middle of the day and the evening peak. On Feb. 6, another storm system led to an unusual load shape where the forecast peak occurred two hours later in the evening than expected, though the scale of the peak was the same as forecast. On Feb. 16, cold temperatures and a storm that brought rain contributed to a 4.13% hourly and 3.18% peak under forecast.

PJM's David Kimmel said there were three shared reserve events, three spin events, one pre-emergency load management load reduction and two cold weather alerts in February. Two shortage cases were issued Feb. 5 due to unit trips and a third was issued Feb. 11 due to a sharp increase in load paired with smaller generation trips.

Feb. 5 saw a spin event lasting 10 minutes and 3 seconds, with 1,827 MW of generation expected to respond and 1,155 MW received, while all 98 MW of demand response (DR) performed. Penalties were assessed against 672 MW of generation that did not respond. Another event the following day lasted 4 minutes and 59 seconds with 1,800 MW of generation expected and 1,149 MW received, while 53 MW of DR was committed and 32 MW responded. A 5 minute, 19 second spin event Feb. 11 expected 933 MW of generation and 1,021 MW received, while 104 MW of DR was expected and 40 MW received.

SOS Updates

Presenting an *update* on System Operations Subcommittee discussions, Hatch said an 85 MW pre-emergency load management deployment was issued in the Ashburn area of Dominion on Feb. 19 to when a transmission line needed to be taken out of service due to issues with a potential transformer. An existing outage caused by a tree falling on a nearby line earlier in the week also contributed to the need for the deployment.

The load reduction mitigated the need for a pre-contingency load shed, which may have been needed to avoid a cascading failure identified under N-5 analysis. The deployment began at 4:20 p.m. and mandatory participation ended at 9 p.m.

PJM conducted its second voltage reduction test Feb. 5, which reduced system voltages by 5% between 7 and 7:30 a.m.

The test was expected to lower loads by 1.9%, or 1,439 MW, but a 0.7% reduction, amounting to 520 MW, was observed. Hatch said there also was a large impact on MVAR capability, with about 2,560 MVARs of generator capability lost, illustrating a need to increase MVAR reserves. ■

— Devin Leith-Yessian

PJM MIC Briefs

Offer Capping Resources with Advance Commitments

VALLEY FORGE, Pa. — The PJM Market Implementation Committee endorsed by acclamation an RTO-sponsored *issue charge* to consider changes to how resources committed in advance of the day-ahead market are offer capped.

Out-of-market commitments have taken on extra significance in recent months as PJM acted ahead of winter storms to schedule additional resources it believed would be necessary to maintain transmission security but had been identified as being at risk of not being able to perform on short notice. That often took the form of resources with limited ramping capability and gas generators that could have difficulty procuring fuel. (See *PJM: 'Conservative Operations' Maintained Reliability During Jan. 2024 Storm*.)

The first phase of the issue charge envisions governing document revisions on the scheduling practices of resources committed before the day-ahead market is run and how they may be offer capped; market power mitigation for those resources is also included. The second phase focuses on adding language fuel expenses in the cost-based offers for units with advance commitments.

The issue charge was revised during the meeting to consider how advanced commitments can impact uplift payments, spell out the timeline for the two phases and designate the Reserve Certainty Senior Task Force (RCSTF) as the forum to coordinate the discussions.

Responding to stakeholder questions regarding whether the issue charge seeks to formalize a practice of making out-of-market commitments on holiday weekends, PJM's Phil D'Antonio said staff plan to discuss the approach operators will take in greater depth at the RCSTF. The next task force meeting is March 12 and is set to include discussion of how winter storms impacted "operations and market outcomes."

Adrien Ford, director of wholesale market development for Constellation Energy, said the company would be abstaining from the vote because it does not support PJM taking out-of-market actions. Instead, she said stakeholders' focus should be on getting the markets right so these actions don't have to be taken. Constellation did not vote in opposition because she said it believes that if PJM is going to continue the practice, there should be rules in place governing how operators act.

Joel Romero Luna, of Monitoring Analytics, speaks at a PJM Market Implementation Committee meeting. | © RTO Insider LLC

Paul Sotkiewicz, president of E-Cubed Policy Associates, said PJM should hold a special session to discuss the intersection of all the issues related to how the gas and electric markets interact. Otherwise, he said, this proposal and the other disparate stakeholder efforts will not yield comprehensive results. "These are really crucial issues from an operational and markets standpoint."

PJM Director of Stakeholder Affairs Dave Anders said the RTO has a desire to move forward on phase 1 quickly and that he believes the issues Sotkiewicz raised pertain to phase 2. He suggested the RCSTF could provide a venue to discuss those issues.

"I think that is directly in the wheelhouse of the RCSTF," Anders said. "I get this idea of wanting a holistic review of everything in one spot and trying to figure out where that is in the manuals. A senior task force is the best place for that to happen."

Periodic Review of Manual 11 Deferred

Stakeholders delayed voting on *revisions* to Manual 11: Energy & Ancillary Services Market Operations following uncertainty around the implications of designating data centers as "plug load."

The language was drafted through the periodic review of the manual, which resulted in changes that PJM's Joseph Tutino said were mainly typographical.

Independent Market Monitor Joe Bowring questioned why data centers should be sorted alongside household appliances like washing machines.

"Data centers are obviously a key issue, and considering them as a regular plug-in load doesn't seem like the answer," he said.

PJM's Maria Belenky said data centers are considered plug load for the purpose of curtailment service providers (CSPs) reporting load enrolled in demand response. The manual does not contain specific guidance for how that load should be categorized, and while it may not be the perfect approach, she said it reflects ongoing practice.

"It is something that is currently done, and it's to provide appropriate guidance for CSPs," she said.

First Read on Proposal to Overhaul Uplift

PJM and the Monitor presented a joint

proposal to rework how the RTO determines when a unit is following dispatch and the process for assigning corresponding uplift payments or deviation charges. (See *PJM Stakeholders Mixed on Uplift Proposal*.)

PJM's Lisa Morelli said the changes seek to resolve an issue where resources instructed to ramp down could instead keep their output flat and nonetheless receive uplift payments. That is because the dispatch signals are ramp-limited and the balancing operating reserve (BOR) credit structure only considers whether a market seller followed dispatch for individual five-minute intervals. She gave an example of a unit operating at 100 MW being dispatched down to 95 MW in accordance with its ramp rate. If that unit ignored the signal and stayed at 100 MW, it would not exceed the 10% margin that defines when a unit is deviating from dispatch. Additionally, because dispatch is limited by ramp rates in the next interval, PJM could only bring it down to 95 MW again.

The proposal would establish a Tracking Ramp Limited Desired MW (TRLD) metric that follows what a unit's output would have been if it had followed dispatch over time. In Morelli's example, the TRLD would continue to fall by an additional 5 MW for every interval that dispatchers sought less energy from the resource.

The TRLD would replace the ramp-limited desired, dispatch and LMP-desired metrics currently used in the BOR credit and deviation formulas, which would seek to make resources whole to the costs they incurred with uplift limited by the output they were instructed to produce based on the TRLD metric.

Morelli said the status quo formula is overly complex and would be simplified by calculating the BOR credits a resource would receive under the lesser of the TRLD and its actual real-time output. This would also remove punitive impacts that market sellers could experience when asymmetric inputs are used in the current formula.

The proposal would also revise the start and end points for uplift eligibility to correspond with when a resource's commitment began and the end of its commitment or minimum run time.

Joel Romero Luna, a market analyst with the Monitor, *said* eligibility for BOR credits is currently defined according to the subjective phrase "operating as requested by PJM," which has been interpreted differently by the Monitor and RTO. The Monitor's position is that one is either eligible to receive uplift when it follows dispatch or not eligible if it does not follow instructions.

Tom Hyzinski, of GT Power Group, questioned whether a market seller that changes its parameters to reflect changes in a resource's flexibility would be held to the original or updated values.

Romero Luna said the proposal changes how a resource that changes the flexibility of its parameters by more than 5% is treated to be dispatched according to its ramp-limited signal, instead of the LMP-desired signal that is not ramp limited. The economic minimum and maximum parameters would remain based on the original parameters at the time of commitment, while the ramp rate and offer parameters would be based on any updates the market seller makes. If a unit submits flexible parameters, but becomes inflexible and does not update, it would be penalized for not following dispatch.

Implementation of the proposal would be phased to start with simulated settlement results being provided to market participants in late 2025 so they can become familiar with how the changes function, with rollout affected actual settlements around a year later.

The MIC is scheduled to vote on the changes April 2, followed by the Markets and Reliability Committee on June 18 and the Members Committee on July 23. Morelli said the proposal would require tariff revisions, which might take long enough to draft to not be finalized by the time the MRC is asked to endorse the package. In that case, a special meeting for a page turn or a second vote may be sought. ■

— Devin Leith-Yessian

PJM PC/TEAC Briefs

Planning Committee

PJM Presents Changes to DESTF Issue Charge

PJM's Chen Lu on March 4 presented the Planning Committee with a draft amendment to the Deactivation Enhancement Senior Task Force's (DESTF) *issue charge* to add a key work activity (KWA) focused on creating pro forma language for reliability-must-run agreements with generation owners seeking to deactivate a unit identified as being necessary for reliability.

The new language seeks a proposal that would be effective for the 2028/29 delivery year, which is the tail end for a temporary measure allowing some resources operating on RMR agreements to be counted as capacity if they meet certain requirements (ER25-682). Approved by FERC in February, the temporary change allows resources that PJM believes can act as capacity to be counted in the supply stack for the 2026/27 and subsequent Base Residual Auction. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

While PJM will ask the Markets and Reliability Committee to vote on the changes during its March 19 meeting, Lu brought the language to the PC, Market Implementation Committee and Operating Committee during their March meetings to provide stakeholders with advance notice.

PJM's Wenzheng Qiu speaks at a Transmission Expansion Advisory Committee meeting. | © RTO Insider LLC

Paul Sotkiewicz, president of E-Cubed Policy Associates, asked Lu why PJM had reversed its earlier position that RMR agreements should be out-of-scope for the DESTF. He stated that RMR agreements are different from other areas the task force has focused on because they are specific to transmission security, not market design.

Lu responded that there are relevant issues around RMR agreements, such as the operational parameters needed to maintain reliability and on the markets side what is needed to count those resources as capacity. PJM believed a senior task force was the best forum rather than a standing committee.

Speaking during the MIC meeting March 5, Philip Sussler, of the Maryland Office of People's Counsel, and Clara Summers, of the Illinois Citizens Utility Board, questioned whether the added work item would impact the ability for the task force to proceed with KWAs exploring alternatives to RMRs, an addition to the issue charge the two consumer advocates sought to have included in 2024. (See "Stakeholders Approve Generation Deactivation Issue Charge," *PJM MRC/MC Briefs: Sept. 20, 2023*.)

Other work areas include education on alternatives to rebuilding transmission assets when generation deactivations would trigger reliability violations, such as reconductoring or the deployment of grid-enhancing technologies; developing alternatives to RMR agreements; and accounting for any changes stakeholders and the RTO may make to its capacity interconnection rights transfer process.

Transmission Expansion Advisory Committee

Market Efficiency

PJM's Nicolae Dumitriu *presented* the Transmission Expansion Advisory Committee with an update on the RTO's 2024/25 long-term market efficiency window.

The congestion drivers behind the analysis were identified through base cases pairing the 2024 load forecast with the expected grid topology in 2029 and 2032. An additional sensitivity was included examining how increased load identified in the 2025 forecast could impact the 2029 case to allow PJM to right-size the solutions built on the two base cases.

The inclusion of the 2024 Regional Transmission Expansion Plan (RTEP) Window 1 slate of grid updates mitigated 13 constraint overloads that prevented the market efficiency analysis from being able to calculate interface limits, in addition to reducing congestion on several lines. The remaining congestion is largely located along the PJM/MISO border. PJM also included planned resources sorted into the fast-track study queue and those with suspended interconnection service agreements (ISAs) to the analysis to allow it to meet the expected 17.8% reserve requirement.

The preliminary congestion drivers identified include the 138-kV Museville-Smith Mountain line in the AEP zone, which has $39.7 million of congestion in the 2029 base case and $51.5 million in the 2032 case; the 115-kV West Point-Lanexa line in the Dominion zone, which has $1.2 million of congestion in 2029 and $1.3 million in 2032; and the 115-kV Garrett-Garrett Tap line in the APS zone, which has $1.8 million in 2029 and $2.4 million in 2032.

PJM's Nicholas Rodak said the next step is finalizing additional sensitivities and the models for the 2025, 2029, 2032 and 2035 simulated years.

Tightening Supply and Demand Impacting RTEP Planning

PJM's Wenzheng Qiu *presented* stakeholders with an update on the assumptions being developed for the 2025 RTEP analysis, which includes an expectation that existing generation and planned resources with signed ISAs will not be sufficient to meet loads in 2030.

Window 1 will include the 2025 load forecast, which includes 16 GW of growth in 2030 above the prior year's forecast.

The five-year analysis of the balance between load and generation finds that peak loads could be met with the addition of projects with suspended ISAs,

fast-lane queue projects, the Chesterfield Energy Reliability Center planned in Virginia and the Coastal Virginia Offshore Wind project, albeit with a loss-of-load expectation of 1.6 days per year. If the 2,308 MW of offshore wind planned in New Jersey and 255 MW in Delaware are not completed, the LOLE would increase to two days per year, 20 times higher than the one-in-10 benchmark.

If all those projects are included in the seven-year base case, Qiu said the 2032 LOLE would be 2.3 days per year. The seven-year case is being included in the analysis to identify projects that could be right sized for long-term needs.

PJM's Sami Abdulsalam said resources with suspended ISAs and fast-lane projects are being included in the RTEP analysis to allow the amount of available generation to meet peak loads. The point of interconnection for those projects is being set at the nearest bus at 500-kV or higher to avoid impacts to lower-voltage facilities. The seven-year case also includes all projects being studied in Transition Cycle 1 and 2, which will also be modeled on the high-voltage backbone network.

Responding to stakeholder questions on how any network upgrades required for those generation projects will interact with the RTEP needs, Abdulsalam said the seven-year case will inform the solutions chosen to resolve the five-year needs. Not all network upgrades expected to be completed in the latter analysis will be included in the five-year case, so any such upgrades would be removed.

Supplemental Projects

FirstEnergy *presented* two projects in the ATSI zone to address transmission overloads and congestion identified in MISO's Long-Range Transmission Planning process (LRTP) and support projects in the 2024 MISO Transmission Expansion Plan.

The first would construct a 20-mile optical fiber line between the Lemoyne and Toledo Edison substations and replace line relaying at Lemoyne at a $15.6 million cost. The second would install 7 miles of fiber from Toledo Edison to the Lallendorf substation, where line relaying would also be replaced, at a $5.9 million cost. The overall $40 million project is in the conceptual phase with a projected in-service date of June 1, 2032.

FirstEnergy also *presented* three projects to replace transformers in the JCPL zone for maintenance issues and the infrastructure approaching the end of its useful life. The 230/115-kV Whippany transformer No. 12 is about 66 years old and has had problems with leaking oil and nitrogen gas; the unit, associated relaying and substation conductor would be replaced at a $8.1 million cost, with an in-service date of March 7, 2030.

The 230/34.5-kV Chester transformer No. 4 is nearly 46 years old and has been reading elevated ethane gas in its oil. Replacing the transformer, a 230-kV circuit switcher, 34.5-kV breaker and limiting terminal components would cost $7.3 million with an in-service date of Dec. 31, 2029. The 230/34.5-kV Chester No. 1 would also be replaced, as it was installed about 60 years ago and there are signs of degrading insulation. Its replacement would cost $7.3 million, which includes a 34.5-kV breaker and limiting terminal components.

FirstEnergy *presented* a $12 million project to replace the control building at its Glade substation in the Penelec zone. The building is 56 years old and degrading, with rusting walls and broken windows. Several line ratings are also limited by terminal equipment. Several other components of the substation would also be replaced, including: four disconnect switches, two 230-kV breakers, and substation conductor and the line trap on the 230-kV Lewis Run-Warren line. Substation conductor and terminal equipment would also be replaced at the utility's Warren and Lewis Run substations. The project is in the conceptual phase with a projected in-service date of Dec. 17, 2027.

American Electric Power *presented* a $173 million project in its zone to connect LRTP Tranche 2 projects to the PJM grid. While the full cost would be assigned to MISO customers, there could be impacts to the PJM grid, so AEP determined to submit them as supplemental projects to be studied for any transmission violations. No "large-scale issues" have been determined, AEP said.

The Sorenson substation would be reconfigured to terminal two new 765-kV lines to the Greentown and Lulu facilities, and four new 345-kV lines would be terminated at the Sullivan substation, with two running each to Fairbanks and Dresser.

Several lines would also be modified to cut into new substations:

- the 765-kV Sullivan-Rockport line would cut into a new Pike County substation;
- the 765-kV Jefferson-Greentown and 345-kV Tanners Creek-Hanna lines would both cut into the Gwynneville substation;
- the planned 345-kV Gwynneville-Tanners Creek line would cut into the existing Batesville substation;
- the 345-kV Fall Creek-Sunnyside line would cut into a new Madison County substation; and
- the double-circuit, 345-kV Olive-University Park and Olive-Green Acres lines would cut into the 345-kV Babcock substation.

Exelon *presented* a $874.2 million project to extend two 765-kV lines from ComEd's Collins substation, which would also be expanded, to interconnect with projects in MISO's Tranche 2.1 portfolio. All costs associated with the project would be allocated to MISO.

A new 765-kV Woodford County substation would be built in the MISO grid as part of the project, which would cut into ComEd's 345-kV Powerton-Katydid and Powerton-Nevada lines. Two 300-MVAR line reactors would be installed at Collins, along with associated circuit breakers for each new line.

Exelon also presented a $40 million project in the ComEd zone to construct a new 345-kV substation, named Eldamain, to serve a new customer bringing 600 MW to the area of its Plano substation. The new facility would be cut into the 345-kV LaSalle-Plano line with 0.4 miles of new double-circuit line. The project is in the engineering phase with a projected in-service date of June 1, 2029.

Dominion Energy *presented* a $30.6 million project to rebuild 10.3 miles of its 230-kV Shawboro-Elizabeth City line as it approaches its end of life, having been built with wooden H-frames in 1975. The project is in the engineering phase with an estimated in-service date on Aug. 31, 2025. ■

— Devin Leith-Yessian

BPA Selects SPP Markets+ in Draft Policy

By Henrik Nilsson, Tom Kleckner and Robert Mullin

The Bonneville Power Administration announced March 6 that it intends to join SPP's Markets+, saying in its highly anticipated *draft policy* that the day-ahead market "is the best long-term strategic direction for Bonneville, its customers and the Northwest."

The purpose of the draft policy is to clarify which day-ahead market offering BPA will pursue and to continue to support the development of Western energy markets, the agency said. Following a 30-day public comment period, BPA expects to issue a final record of decision in May, according to a news release.

BPA choosing Markets+ over CAISO's Extended Day-Ahead Market (EDAM) is perhaps unsurprising given an agency staff report published in April 2024 recommending that it join SPP's offering. Still, the draft policy follows months of discussions and debates about the impact of BPA's choice on Western electricity markets and customers. Even United States senators have weighed in. (See *BPA Staff Recommends Markets+ over EDAM* and *BPA Has not Made 'Business Case' for Markets+, NW Senators Say*.)

BPA said it landed on Markets+ based on "overall market design features, including an independent governance model, uniform resource adequacy requirements, superior GHG design and congestion revenue design that incentivizes transmission investments."

Independent governance has been a key consideration for BPA. Staff have argued that Markets+ provides greater independence from California state influence compared with the EDAM option. The draft policy reiterates this point, saying that "independent market governance continues to be paramount to Bonneville's policy direction towards participation in Markets+." It notes that Markets+ will be governed by an independent panel whose members "must be independent of market participants."

By contrast, efforts launched by the West-Wide Governance Pathways Initiative to ensure independent governance of CAISO's EDAM and Western Energy Imbalance Market (WEIM) have not gone far enough, it says.

A proposal under Step 1 of the Pathways Initiative to elevate the Western Energy Markets Governing Body's authority over CAISO energy markets was approved unanimously by the body and ISO's Board of Governors in 2024. (See *CAISO, WEM Approve Pathways 'Step 1' Tariff Amendments*.)

Still, the board will continue to exercise some influence, and "critically, the day-to-day management of policy development and market operations remains with CAISO management, who ultimately report to the" board, the policy states.

California lawmakers recently introduced SB 540, or the Pathways Bill, setting conditions under which CAISO and Golden State utilities can participate in energy markets governed by an independent regional organization. (See *Pathways 'Step 2' Bill Sets Conditions for EDAM Governance*.)

However, passage of the bill is not guaranteed, and though BPA supports the effort, "the current Pathways proposal does not go far enough to meet … what our expectations are of an independent governance model," Rachel Dibble, BPA vice president of bulk marketing, told reporters.

Why This Matters

Independent governance has been a key consideration for BPA, whose staff argued that Markets+ provides greater independence from California state influence compared with the EDAM option.

Dibble added that BPA believes the ideal governance model already exists within the Markets+ framework, saying "it's there for us right now. [With] the California model, the changes are still just speculative."

Jayme Ackemann, CAISO's head of communications, told *RTO Insider* that the ISO appreciates BPA's contributions to the development of regional markets in the West. She noted that BPA and other utilities have benefited from the WEIM, saying the real-time market "has delivered substantial reliability benefits and cost savings of nearly $7B to consumers."

"BPA's final market decision will have major impacts on reliability and affordability for electricity customers in the Northwest and across the West," Ackemann said. "We encourage BPA to continue to evaluate EDAM and engage in the Pathways Initiative as governance reform legislation works its way through the California legislature."

Antoine Lucas, SPP's vice president of markets and incoming COO, also offered his thoughts, saying SPP is encouraged by BPA's draft policy.

"From the outset, our goal has been to provide a competitive market option that could earn the participation of Western stakeholders," Lucas said. "Through its detailed analysis of day-ahead market choices, BPA has concluded in its draft policy paper that Markets+ will provide the most benefits for their customers."

Reaction Through the West

Scott Simms, executive director of the Portland, Ore.-based Public Power

BPA's The Dalles Dam | © RTO Insider LLC

Council (PPC), said "BPA's decision to move forward with Markets+ underscores the strength of the SPP Markets+ option, which was designed by diverse stakeholders across the West."

"With many utilities across the Northwest and Southwest already supporting Markets+, this decision signals even greater momentum toward a broad and well-structured market that delivers reliability and cost benefits," Simms added. "We encourage additional utilities to consider joining this effort to further enhance regional coordination and market efficiencies."

The PPC, which represents the Northwest's extensive network of publicly owned utilities that make up BPA's base of "preference" customers, began actively urging BPA to choose Markets+ over EDAM even before the agency's staff issued its "leaning" in favor of the SPP market last spring. (See *Northwest Public Power Group Endorses Markets+ over EDAM*.)

In its statement, the PPC pointed to the SPP market's "well-defined, inclusive and transparent decision-making process that ensures public power's interests — along with those interests of other stakeholders and participants — are represented and protected over the long term."

PPC Chair Chris Robinson, general manager of Tacoma Power, said the group appreciated "BPA's thoughtful approach and transparent process used to reach this decision."

Meanwhile, Seattle City Light expressed disappointment with the decision.

"Having two markets in the region is inefficient [and] will negatively affect consumer rates and potentially cause adverse effects on regional greenhouse gas emissions reductions and reliability, especially during extreme weather events," said City Light CEO Dawn Lindell. "We remain steadfast in our position that our customers are best served with an efficient, well-connected and integrated market."

Brian Turner, Western regulatory director at Advanced Energy United, shared City Light's sentiment. Turner said in a statement that BPA failed to consider the many stakeholders who urged it to pause its market decision.

"Joining a smaller, more balkanized market undermines the very affordability and reliability of clean energy resources that the region depends on," Turner said. "By rushing into this decision, BPA risks hitching its wagon to the wrong horse. With this decision, we are now heading toward a bifurcated West that will be intermeshed with costly seams running all over the region. Working together in a larger, more unified market, the West could be an energy powerhouse for the nation, but this decision threatens to put that vision out of reach."

The NW Energy Coalition noted that studies, including one commissioned by the agency itself, found that BPA would realize significant benefits by joining EDAM instead of Markets+. (See *BPA Sticks to Markets+ Leaning Despite Study Showing EDAM Benefits* and *Brattle Study Finds EDAM Gains, Markets+ Losses for BPA, Pacific NW*.)

"In the coming weeks, we will further analyze this proposal and work to align BPA's final decision with the best interest of all regional stakeholders," NWEC Executive Director Nancy Hirsh said.

However, BPA has argued that the studies show a wide range of outcomes and cannot capture the full economic picture.

"In addition, this has never been a purely quantitative decision," BPA's Dibble told reporters. "We have really significant beliefs about the importance of governance, the importance of an open stakeholder process, and while those cannot be quantified, those are qualitative elements that we hold as very high priorities."

She said those qualitative factors will, in the long run, lead to "positive quantitative benefits" because of Markets+'s "equitable" governance framework.

Asked whether BPA is concerned about the lack of transmission connectivity among entities that have committed to Markets+, and whether those entities are seeking to take steps to ensure the ability to trade, Dibble said the agency's policy paper acknowledges the "limited connectivity between regions that we do hope, over time, will become more robust," but she acknowledged that no plans for new transmission are in place.

"However, recognize that the final footprints are not solidified at this point," she added. "There are still several entities who may have leaned in one direction that could rethink their decision because they have not signed agreements at this point. There are some that have been silent who could now step up with a decision and join either footprint. So I think it is premature to believe we know exactly what the footprints are going to be." ■

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BPA to Restore 89 'Probationary' Staff, Agency Confirms

DOE Could Grant Northwest Power Agency Exemptions from Reductions in Force Order

By Robert Mullin

The U.S. Department of Energy will allow the Bonneville Power Administration to reinstate 89 "probationary" employees and could provide the federal power agency exemptions from the Office of Personnel Management's reductions in force (RIF) order, a BPA representative has confirmed to *RTO Insider*.

"We are working to get more exemptions from the RIF," the representative said March 6.

The representative said they believed the 89 reinstatements would be in addition to the 40 probationary staffers already restored to their positions.

The move comes after *OPM updated its guidance* to department heads, saying that it was up to them whether to fire such workers.

Despite BPA's status as a self-funding federal agency, its staff in January received the same "deferred resignation" buyout offer from President Donald Trump's unofficial Department of Government Efficiency, immediately setting off alarms in the electricity sector about the impact on the region's grid reliability. (See *BPA Employees Confront Trump's 'Fork in the Road'*.)

During a quarterly business review call Feb. 13, BPA Administrator John Hairston said about 200 agency employees — or 6% of the workforce — had accepted the Trump administration's buyout offer, while 90 job offers had been rescinded following a federal hiring freeze announced Jan. 20.

Last month, Sens. Jeff Merkley and Ron Wyden, both Democrats of Oregon, called on the Trump administration to justify what they called "reckless" and "financially ludicrous" cutbacks that could compromise BPA's ability to maintain grid reliability. (See *Ore. Senators Ask Trump to Justify 'Reckless' Job Cuts at BPA*.)

Scott Simms, executive director of the Portland, Ore.-based Public Power Council, previously told *RTO Insider* that he estimated BPA faced a loss of about 400 staff, which included resignations and the firing of probationary employees. Simms also warned about massive cutbacks of vital technical positions at the U.S. Army Corps of Engineers, the agency that physically operates most of the hydroelectric dams in the Northwest. (See *2 Top BPA Execs to Depart; Army Corps of Engineers also Faces Massive Cutbacks*.)

Asked what might have turned the tide for BPA, Simms said: "While I have no direct knowledge of how a potential RIF may or not be considered for BPA, I am certain that the extensive industry and congressional outreach about the critical nature of the work BPA does — and the fact that it is a ratepayer-funded and not taxpayer-funded federal agency — really moved the needle on the probationary employee reinstatement."

Simms added that the PPC is "incredibly grateful to DOE for hearing that message and for taking action to restore these critical workers to their jobs, and we are hopeful that as government-wide RIFs are considered, BPA and its federal generating agency partners can be exempted because of their important missions." ■

Why This Matters

Any DOE moves to restore staff at BPA and prevent further cutbacks should settle nerves in the Northwest about the potential threat to grid reliability that would come with the loss of valuable staff.

BPA headquarters in Portland, Ore. | *Bonneville Power Administration*

Former BPA Leaders Again Protest Workforce Cuts

Wright, Hardy Stress Importance of Grid Reliability

By Tom Kleckner

IRVING, Texas — Former Bonneville Power Administration heads Randy Hardy (1991-1997) and Stephen Wright (2000-2013) have again collaborated on a public letter distributed in the Pacific Northwest about the "tremendous risk being created" in the region by workforce reductions at the federal agency.

In a *letter* made public March 3, which followed a *previous letter* in February, Hardy and Wright argued that the reductions will not realize taxpayer savings, as all BPA expenses are funded through electricity rates charged to its utility customers and passed on to retail consumers. They noted that the federal power marketing administration has already lost 14% of its workforce and a fifth of its power dispatchers, endangering the entire Northwest power grid.

"There has been no strategy to the workforce reductions such as targeting less important positions, or fencing off positions critical to ensuring public health and safety such as power dispatchers and lineworkers," the former administrators wrote. "While BPA management is strictly limiting communication, from our experience we can presume that management is now attempting to plug round pegs into square holes and in many cases not having anywhere near enough pegs."

"The implications of those people dropping out of the workforce without a plan just leads one to question: 'What are the impacts going to be?'" Wright, a member of SPP's Board of Directors, told *RTO Insider* as the letter was being released. "When you have people that are everything from duty schedulers, hydro schedulers to linemen, it just leaves you with a bunch of questions about, well, how are they going to manage through this? And then what implications are there for others that are impacted by their operations? They're so interconnected, there's a chance that that could be widespread."

The administrators added three concerns to those expressed in their previous letter:

- The reductions will increase outage repair times across BPA's six-state region.
- Employee safety will be compromised with crews stretched thin and likely requiring more overtime.
- Geopolitical tension translates to risk of cybersecurity intrusions.

SPP director Steve Wright (right) has again teamed up with a former BPA administrator to protest workforce reductions at their former agency. | © *RTO Insider LLC*

Why This Matters

Randy Hardy and Steve Wright argue that Bonneville Power Administration's workforce reductions are a direct threat to reliability and don't save taxpayers 'one dime.'

"We reemphasize that we strongly support seeking efficiency gains especially through the adoption of new technology," Hardy and Wright wrote. "But electricity delivery, unlike many other businesses, is a function where the public reasonably expects — and public health and safety demands — round-the-clock, uninterrupted service."

They closed their missive by asking for relief from the Department of Energy, urging a total exemption from pending reductions, lifting an existing hiring freeze, rehiring the 100 or so probationary employees already laid off, and exempting the U.S. Army Corp of Engineers and Bureau of Reclamation staff who are funded by BPA revenues.

BPA is part of DOE and provides about 28% of the Northwestern U.S.' electricity, managing a 15,000-mile transmission network. It is one of the key potential participants in SPP's Markets+, a day-ahead service offering. Wright serves as chair of the Interim Markets+ Independent Panel and is one of three SPP directors serving on it.

The letter was written for those in the Northwest and distributed by the Public Power Council and others. Hardy took the *message* to *The Seattle Times*.

Wright said he and Hardy are simply doing what others can't.

"We're putting information out right for people to be aware of," he said. "The problem is, it's difficult for the agencies

to talk about this, and so, to some extent, we have to surmise some things. But between Randy and me, we just have enough years having been at Bonneville; we can put pieces together that it might not be easy for other people to put together."

Wright was speaking during a break in SPP's Energy Synergy Summit. In a separate meeting earlier that day, he asked SPP legal staff about staff reductions at FERC and the potential effect on the grid operator's "specific issues."

"I was asking the question because I don't know what's going on, but the way [job reductions] landed at Bonneville, I don't know why it would be significantly different: … the relatively random nature in which people are choosing to resign, or the implications of probationary employees," he said. "And by the way, 'probationary employee' doesn't mean that they're new."

According to the *U.S. government*, probationary federal workers are new or reassigned employees under evaluation during a trial period, which generally lasts a year. A federal employee can become probationary with a transfer or new job within the same department.

When it was pointed out to Wright during the meeting that he is helping to raise awareness of the layoffs and their potential effect on the Northwest, he said, "This is a very active conversation in the Northwest."

"The thing that really is bothersome about this is that it doesn't do anything for the federal deficit," he said.

In the letter, Wright and Hardy wrote, "Reducing BPA staff does not save U.S. taxpayers one dime."

The former administrators are not alone in expressing their concerns over the BPA job reductions. Wright reeled off a list of several other public figures who are also speaking up: All but one of Washington state's Democratic U.S. representatives, who wrote a letter to Energy Secretary Chris Wright (Rep. Marie Gluesenkamp Perez was the lone holdout); Energy and Commerce Committee member Rep. Kim Schrier (D-Wash.), who made a speech on the House floor; and Oregon's U.S. senators, Ron Wyden (D) and Jeff Merkley (D), who wrote a letter to President Donald Trump. (See *Ore. Senators Ask Trump to Justify 'Reckless' Job Cuts at BPA*.)

Wright said the only Pacific Northwest Republican who has spoken about the issue is U.S. Rep. Dan Newhouse (Wash.). "He did it in a newsletter to his constituents, just saying he's concerned about the impacts on the energy and research issues. He also has a National Lab in his district," Wright said.

Asked if the outreach to the government and stakeholders is working, Wright said, "It's definitely getting attention. I mean, a fair amount of attention."

Fred Heutte, senior policy associate with the Northwest Energy Coalition, agreed with the sentiments in the letter. He told *RTO Insider* that though NWEC disagrees with BPA on many issues, "we are absolutely committed to the idea that Bonneville must have the staff to operate the system day-to-day."

The staffing crisis "is a direct threat to reliability," Heutte said. He added that regional entities, such as WECC, "have a role in standing up and saying that their main focus under the [Energy Policy Act of 2005] is reliability."

Heutte sits on WECC's Member Advisory Committee. The organization oversees compliance with reliability standards. It also conducts resource assessments and planning functions for the Western Interconnection.

Approximately 90 million people are served in the Western Interconnection. Heutte said that WECC speaking up would send a "very important signal."

"We want people to say, 'If I flip the switch, the lights will go on.' That's a good thing, but there's an enormous amount of work and enormous amount of vulnerability now to not having the staff sufficient to make that happen. So I hope at the appropriate time that WECC will speak up."

When asked to comment on the letter, BPA spokesperson Doug Johnson told *RTO Insider* in an email that "there is nothing in the letter we feel the need to correct or expand upon."

"WECC is aware of the personnel impacts at Bonneville Power Administration and other federal entities in the West," Kris Raper, vice president of strategic engagement and external affairs at WECC, told *RTO Insider* in an email. "We will continue to monitor the situation as it develops, including collaborating and coordinating with BPA and other electric industry owners and operators in support of their role in serving customers with the essential power that they need." ■

7th 'Issue Alert' Highlights Markets+ Footprint

By Henrik Nilsson

Proponents of SPP's Markets+ argued in their latest "*issue alert*" published Feb. 28 that the day-ahead market option provides a robust footprint with "exceptional generation and load diversity" across the region while also claiming recent warnings about its seam with CAISO's Extended Day-Ahead Market (EDAM) are overblown.

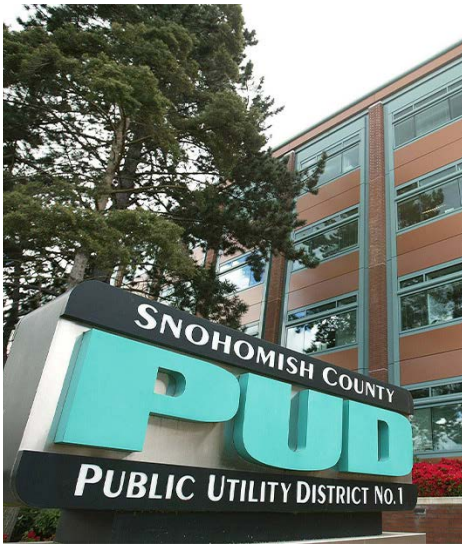
The alert is the seventh and last in a series of notices highlighting the purported advantages of Markets+ over EDAM and the Western Energy Imbalance Market (WEIM). The alerts have covered topics such as governance, reliability, pricing practices, market seams, emissions and market operations.

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

In their seventh alert, the proponents argued Markets+ will "be substantial in size with exceptional generation and load diversity." For example, the market will have peak demand of over 52 GW and annual demand of over 280 TWh; a significant mix of resource diversity; clean flexible supply; and a "large geographical footprint — encompassing parts of 11 different states — resulting in a reduced probability that heat waves and cold snaps affect the entire Markets+ footprint simultaneously."

The alert also took aim at recent production cost studies, some of which have suggested EDAM would provide the most because of its large footprint, which includes California. (See *Brattle Study Shows Big Benefits for California in 'Expanded' EDAM*.)

However, the studies do not capture the full economic picture and fail to account for the differences in market design between Markets+ and EDAM, the alert argued. The models assume Markets+ and EDAM will be isolated with limited trade when, in reality, entities in each will continue trading with one another, it said.



Snohomish County PUD in Washington is one of the joint authors of the "issue alerts" supporting SPP's Markets+. | *Camano Island Chamber of Commerce*

"This defies real-world expectations and ultimately promotes an incorrect conclusion that being in the largest possible market footprint should be the only relevant consideration informing an entity's market choice above all other factors, including fundamental differences in governance and market design that are not evaluated by these studies," the proponents contended.

John Tsoukalis, a principal at The Brattle Group, contended that the alert "mischaracterizes" assumptions Brattle studies have made regarding market seams.

"Our studies show that there continues to be significant trading across the market seams. In fact, we assume a lower hurdle rate to trade between Markets+ and EDAM than we do to trade bilaterally between two utilities in the WECC," Tsoukalis told *RTO Insider*.

"The issue alert does not name our study directly, so perhaps they are referring to the assumptions used in other studies and assuming all production cost studies are the same. That is not the case," he said.

Tsoukalis noted also that some stakeholders "have confused long-term bilateral transactions across market seams with short-term day-ahead trading across market seams." He said Brattle's model treats the two types of transactions differently, with long-term transactions showing no transaction costs while costs applied to short-term transactions under a two-market scenario are assumed to be lower than costs observed today in the West.

The alert also covered congestion costs. The proponents argued that Markets+ provides enhanced protection from congestion costs by allocating congestion revenue to firm transmission rights holders in proportion to the congestion costs incurred on their specific transmission paths.

In contrast, EDAM participants will miss out on robust congestion cost protections, the proponents claimed.

"EDAM will not return these congestion charges back to the firm [open-access transmission tariff] rightsholders that are exposed to the congestion costs and will instead return the revenue to the [balancing authority area] where the constraint is located, which public data show is most often the CAISO BAA," the alert argued. "Among the many negative consequences of this design, it is likely to impose large new costs for the transmission customers and ratepayers of EDAM participants outside of California, to the benefit of customers in the CAISO BAA."

When asked to comment on the issue alert, CAISO's head of communications, Jayme Ackemann, pointed to another study by the Brattle Group that suggests some EDAM participants "could conservatively save consumers nearly $900 million annually." (See *Updated EDAM Study Shows Doubling of PacifiCorp Benefits*.)

Ackemann also pointed to the West-Wide Governance Pathways Initiative, an effort to ensure independent governance of CAISO's EDAM and WEIM. California state lawmakers recently introduced legislation as part of the initiative. (See *Pathways 'Step 2' Bill Sets Conditions for EDAM Governance*.)

"With FERC's approval of EDAM's market design and more than 50% of the load in the West planning to participate, it is clear that maintaining a strong, geographically diverse and interconnected system is crucial to maximizing consumer benefits through widespread participation in WEIM and EDAM," Ackemann added. ■

SPP Stakeholders Grapple with Energy Transition

Large Loads, Data Centers Complicate Grid's Reliability Needs

By Tom Kleckner

IRVING, Texas — Taking the stage to welcome attendees to SPP's Energy Synergy Summit, incoming CEO Lanny Nickell said the two-day event has been long in the planning.

"It's something that we've been wanting to talk about for a long time," he said during the March 3-4 event. "I've been in this industry a long time. I've seen a lot of change, but we're changing at a rate that is faster than I've ever seen before, and that makes it exciting to be part of this industry.

"So that's what we're intending to talk about today. How can we align resources with the demand that we know is increasing?"

Exciting? With SPP already seeing changes in the resource mix from renewable sources? With thousands of megawatts of dispatchable generation retiring, as Nickell said? With load growth increasing at levels seldom seen?

The challenge, he told the 280 attendees — an SPP record for an external meeting — is infrastructure.

Case in point: SPP's approval in November of a record breaking $7.65 billion transmission planning portfolio of 89 projects, including its first 765-kV project. (See *SPP Board Approves $7.65B ITP, Delays Contentious Issue*.)

"With all of the load growth we're already seeing, the challenge is to have the resources we need. We need to add more, and we need to add more quicker. With the change in risk, we have to get ahead of the game. We have to add transmission. It's coming, but it can't get here quick enough," Nickell said.

"The questions we have to answer, and it starts today, is how can we do this reliably? How can we do this affordably? How can we add the generation we need quicker? How can we add the transmission we need quicker? What can we do with the system that we have today? Those are the questions that have to get answered."

"I think if we could go back like five years and we talked about [Texas'] economy, things started changing pretty quickly," ERCOT COO Woody Rickerson said during a later panel discussion. "We thought, 'Man, this is grid transformation. Focus is really accelerating.' It was nothing compared to what's going on now. All the reports, all the dashboards, everything we do is different now because you've got this energy component. And then on top of all that, you come in with 10,000 MW of data center load. … So, yeah, it's kind of the Wild West of the grid right now. I think we're going to see even five or 10 years of really rapid changes, and what we come out with is not going to be anything like what we have today."

SPP director Irene Dimitry moderates a panel featuring (left to right) SPP's Antoine Lucas, PJM's Adam Keech and ERCOT's Woody Rickerson. | © RTO Insider LLC

Why This Matters

Change is coming faster than ever seen before, says incoming SPP CEO Lanny Nickell. Aligning resources with the ever-growing demand will require investments in transmission infrastructure.

Morgan Scott, vice president of sustainability and global outreach for the Electric Power Research Institute, offered some pathways forward. She said flexibility is the key to meeting load growth, in addition to forecasting, stability and reliability, and adequate supply and delivery capacity.

This includes flexibility with the transmission system, where additional infrastructure can be slow in coming.

"As one person put it on a roundtable I was facilitating last year: 'I've got to sweat my transmission assets as much as I can sweat those things. I have to squeeze as much capacity out of the transmission system as I can,'" she recalled. "This is the conversation that starts to get around [grid-enhancing technologies], right? How do we get these technologies onto the system that help us to take advantage of the system that is already built as is today?"

Scott used what she said was an ancient Greek proverb, often attributed to Warren Buffett, to make her case for continued infrastructure investment.

"Society prospers when old men plant trees that they're never going to sit in the shade of," she said. "The concept fits so right for me as we think about this particular moment in the power system and this industry. We've got to be making decisions and investments today in the grid

that we're not going to necessarily see the benefits of. … I encourage us to really think about what's the power system that we need in the next 30 to 50 years, and how do we make those responsible decisions now?"

SPP's incoming COO, Antoine Lucas, agreed during his panel's discussion of how best to adapt to the new digital era. He said the grid operator is using its transmission planning process to ready itself for "many different circumstances."

"We look at various different scenarios that give us the opportunity to identify needs that are consistent across those different futures, and we try to use that information to lead us to more of the no-regrets type of transmission plan under that circumstance," he said. "If we're going to recommend an investment, we know it's going to address an issue or at least we're highly confident that it's going to address an issue on the system. The question just becomes the appropriateness of the scale of the project [minimizing] some of those risks or concerns, but that also puts us in the position to be able to meet the challenges and needs."

Roger Freeman, head of power for Talus Renewables, provided a customer's perspective, saying their engagement can be useful in designing the systems of the future.

"I think it's useful that we're having sort of a high-level conversation about system planning. That's really important as we think about the big questions for how we structure our energy system," he said. "I think as we sort of build the energy system of the future, that conversation needs to change a little bit to broaden out the range of options.

"So I would say to the regulators and

Roger Freeman, Talus | © RTO Insider LLC

Morgan Scott, EPRI | © RTO Insider LLC

others in the utilities in the room, 'How do we sort of change the mindset so we can have sort of a more dynamic conversation,' so it's not just 'Tell me what you want, I'll build it and rate base it,' but it's 'Here's the different ways that you could build a system that you want to build,'" Freeman added.

Kim David, elected to the Oklahoma Corporation Commission in 2022 and now its chair, said she expected a boring job when she joined the OCC. Now, she says, "This is a pretty exciting time moving forward."

"You guys also speak a different language, but being innovative and thinking outside the box," she said. "Yes, we have to keep our reliability, and we have to make sure everything is used and useful and we protect our customers. But it is truly with new technology happening, I think this is a time to let the free market have the reins and come up with some innovative ideas to bring forward to us on how to put it together."

"The main message here is we're dealing with innovation," said NextEra Energy Resources' Mark Ahlstrom, who chairs SPP's *Future Grid Strategy Advisory Group*. "Innovation is kind of like a fast form of evolution. It's a very unstoppable force. We can shape it, we can't just get in the way and say, 'Stop.' It'll go either right through you or around you and find another way of accomplishing it. We really have to embrace this as an opportunity to innovate and figure out how we're going to do that at many levels."

Former Texas Public Utility Commissioner Will McAdams, who now runs his eponymous energy group and partners with a lobbying firm, recalled his days at the PUC and as its liaison with SPP. The experience was eye-opening.

"I got to see the Wild West, which was ERCOT, and then I got to see the opposite of the Wild West, which was SPP, and that was a world of free-wheeling, Libertarian, valued regulations," he said. "Do you build it? We'll figure out how to make it work together. That's a tough world for an ISO/RTO manager to manage, and then you have SPP. It's the land of the 16 kingdoms, the transmission owners, and the elders that rule it with an iron fist, and nobody wants to change that.

"And so that's a great experiment of who's going to win the race on this data center employment, who's going to win the race in attracting large loads to their region and thus experience the benefits of the diverse risk cycle of tax base, economic development and job growth partnership," McAdams added.

"There might be a happy medium between the Wild West and the people that make up that Wild West and the 16 kingdoms. How do you work within the needs of the utility to create the synergies between the load and the utility, to allow the opportunity to scale at the same time providing the reliability needs and, frankly, the cost allocation necessary to bring costs down at the same time as building out infrastructure to bring more loads? And I believe that is possible."

Lucas shared McAdams' optimism as he reflected on the conversations surrounding large loads.

"I hear a wide range of perspectives about it, from some that are excited about it but then there are others who say, 'I just don't want it, don't need it,'" he said.

But wherever you stand, Lucas said, additional investment and transmission infrastructure will be needed to maintain grid reliability.

"That's the numerator in the equation, but I think about these large loads as a real opportunity because to the extent we're able to significantly increase the denominator in that equation, that might be our ticket to be able to fund the investments as necessary to maintain reliability and do it in a fashion that's affordable," he said. "So I would implore everyone here to think about the opportunity in front of us and how we may be able to take advantage of that opportunity to create some affordability as we get through this transition." ■

SPP Briefs

Simpson Promoted to Vice President of Markets

SPP says it has named Carrie Simpson, a key figure in its expansion efforts in the Western Interconnection, as its vice president of markets, effective April 1.

Currently the RTO's senior director of seams and Western services, Simpson will replace Antoine Lucas, who was recently promoted to COO.

Simpson will be responsible for overseeing the development, design and delivery of all SPP market-based services and will serve as the executive sponsor of the Markets+ effort, a regional day-ahead wholesale market that is in its second stage of development.

Simpson helped develop SPP's Integrated Marketplace — a next-day market that serves as the foundation of the RTO's Western market offerings — before taking a position as Western markets director with Xcel Energy subsidiary Southwestern Public Service in Colorado in 2015. She rejoined the RTO in 2022. (See *SPP Brings Back Ex-staffer to Develop Western Services*.)

Simpson has more than 20 years of industry experience. She holds an undergraduate degree from Harvard University and a law degree from the University of Denver's Sturm College of Law. She is licensed to practice law in Colorado.

SPP Opens Denver Office

SPP has opened an office in Denver, a logical decision given the grid operator's *many activities in the Western Interconnection*. Since 2019, SPP has:

Carrie Simpson makes a point during an SPP Markets+ stakeholder meeting. | © RTO Insider LLC

- served as a reliability coordinator in the West;
- stood up the Western Energy Imbalance Service market;
- operated the Western Power Pool's Western Resource Adequacy Program;
- attracted seven members as part of its RTO expansion into the West, scheduled to go live in 2026; and
- begun development of Markets+.

SPP would not be the first grid operator with satellite offices: Neighboring MISO has offices in Eagan, Minn., and Little Rock, Ark., in addition to its corporate headquarters in Carmel, Ind.

The Seams Advisory Group inaugurated the office's conference room with a meeting March 7. SPP's Jena Arnold told stakeholders the RTO expansion effort is in a holding pattern while waiting on FERC approval of its filed tariff before it can begin collaborating with other planning regions. The RTO expects to set up joint operating agreements with at least nine other utilities in the West.

New Winter Peak Set

C.J. Brown, SPP's director of system operations, told the Resource and Energy Adequacy Leadership (REAL) Team on March 3 that the RTO set a new winter peak of 48.14 GW in its balancing authority area Feb. 20.

"It was very, very tight," Brown said. He noted that SPP relied on 3 GW of imports to make up for a loss of wind production that was down that day as compared to Feb. 19. He promised a full presentation before the Markets and Operations Policy Committee with "plenty of graphics and details."

The REAL Team did not take up any voting items during its short meeting before SPP's Energy Synergy Summit. ■

— Tom Kleckner

Company Briefs

Sunnova Names Mathews President, CEO

Sunnova Energy International last week announced that former COO Paul Mathews has been appointed president and CEO, effective immediately.

Mathews joined Sunnova in January 2023. Prior to that, he spent nearly two decades serving in a variety of leadership roles at UPS.

Mathews succeeds William Berger, who is stepping down as chairman, president and CEO.

More: *Sunnova*

Alliant Energy Appoints New Board Chair

Alliant Energy last week announced the appointment of Patrick Allen as the new independent board chair, effective following the company's Annual Meeting of Shareowners in May.

Allen has been a member of Alliant's board since 2011.

He will succeed John Larsen, who will retire.

More: *Investing.com*

RWE to Lay off Some of Boston Workforce

German energy company RWE Offshore Wind Services plans to lay off 73 employees from its Boston-based U.S. offshore wind arm, according to state filings.

Company spokesperson Ryan Ferguson said the layoffs, which will come by May 6, will affect workers supporting the long-term development of offshore wind projects across the country.

More: *Boston Globe*

Federal Briefs

GAO Blocks Vote to Repeal California EV Rules

The Government Accountability Office last week said the Biden administration's approval of California's plan to end the sale of gasoline-only vehicles by 2035 is not subject to review and potential repeal by Congress.

Last month, the EPA sent the approval to Congress saying it was considered a rule under the Congressional Review Act. The GAO said the decision should be considered an order and is not reviewable.

California's rules require 35% of vehicles in the 2026 model year to be a zero-emission model before rising to 68% by 2030.

More: *Reuters*

US to Withdraw from Coal Transition Partnership

The United States is withdrawing from the Just Energy Transition Partnership, a collaboration between richer nations to help developing countries transition from coal to cleaner energy, sources in participating countries said.

The coalition, which consists of 10 donor nations, was first unveiled at the U.N. climate talks in Glasgow, Scotland in 2021.

The U.S. state department did not respond to a request for comment.

More: *Reuters*

BLM Approves Newcastle Geothermal Development Project

The Bureau of Land Management last week approved the Newcastle Geothermal Development project in Utah.

The plant is expected to generate up to 20 MW near Newcastle in Iron County.

More: *BLM*

State Briefs

ALABAMA

Alabama Power to Install BESS

Alabama Power has announced plans to develop the first utility-scale battery energy storage system (BESS) project in the state.

The 150-MW Gorgas BESS will be installed at the site of the retired Plant Gorgas power station in Walker County and will cover 7 acres.

Construction is set to begin this year, with commercial operations planned by 2027.

More: *Renewables Now*

CALIFORNIA

LA County to Sue SCE over Eaton Fire

Los Angeles County last week said it will sue Southern California Edison, alleging the utility's equipment sparked the Eaton Fire.

The lawsuit seeks to recover costs and damages sustained from the fire. Costs and damage estimates were expected to total hundreds of millions of dollars, the county said, adding that assessments were ongoing. The blaze destroyed more than 9,400 structures and killed 17 people in the Altadena area.

More: *The Associated Press*

IOWA

Bill to Block CO2 Pipelines from Eminent Domain Advances

The House Judiciary Committee last week advanced bills to block liquid pipelines carrying carbon dioxide from the use of eminent domain.

One bill specifies that the "construction of hazardous liquid pipelines for the transportation or transmission of liquefied carbon dioxide" does not constitute a public use for the purpose of condemning agricultural land. The bill would apply to any condemnation proceedings made on or after its enactment. Another bill would restrict liquid pipelines from the right of eminent domain.

A companion bill in the Senate has not had any scheduled hearings and will likely be dead.

More: *Iowa Capital Dispatch*

KENTUCKY

Utilities Request Approval for Natural Gas, BESS

Louisville Gas and Electric and Kentucky Utilities have requested approval for a Certificate of Convenience and Necessity from the Public Service Commission for two natural gas plants and a battery energy storage system (BESS).

The two 645-MW natural gas plants would supply additional generation at the E.W. Brown Generating Station. The companies expect to have the units available in 2030 and 2031.

The companies also plan to install 400 MW of BESS at the Cane Run Generating Station and a selective catalytic reduction facility to reduce nitrogen oxide emissions for Ghent Unit 2. These are expected to be operational in 2028.

More: *Energy Storage News*

MINNESOTA

Xcel Energy Proposes $318M in Refunds to Customers

Xcel Energy officials said they are proposing returning $318 million to customers.

According to a news release, more than half of the refund ($176 million) comes from federal tax credits for nuclear energy generation, with the remainder would come from lower fuel costs and a 2011 outage at the Sherco coal plant.

The refunds, which would total $81 for the average residential customer, must be approved by the Public Utilities Commission.

More: *KARE*

MONTANA

Bill to Allow Community Solar Projects Clears Senate

The Senate has passed a proposal that would establish a legal framework for community solar power projects.

If the proposal passes the Legislature, it will allow a solar developer to build a solar array between 50 kW and 5 MW and sell shares of the generation to subscribers. It would also require the Public Service Commission to come up with a framework for pricing the electricity generated.

More: *Montana Free Press*

PENNSYLVANIA

Canada Bitcoin Miner Acquiring 2 Coal Plants

Canada-based crypto mining company Bitfarms last week announced it is acquiring two coal-fired power plants to power its bitcoin mining operations.

Bitfarms is set to buy Stronghold Digital Mining in a deal expected to close this month. Stronghold owns the 85-MW Scrubgrass waste plant in Venango County and the 80-MW Panther Creek waste facility in Carbon County.

Bitfarms already has a presence in the state, having purchased a data center in Mercer County last year.

More: *POWER Magazine*

RHODE ISLAND

Carrier to Credit Ratepayers in Fraud Case Settlement

The Public Utilities Commission last week approved a settlement that will have Rhode Island Energy credit ratepayers $7.9 million for an alleged fraud scheme by its predecessor, National Grid.

In December 2021, the PUC discovered that National Grid knowingly misfiled invoices for its energy efficiency program over an eight-year period to make more money, overcharging customers as much as $2.2 million. National Grid acknowledged in a 2023 report that company employees "acted inappropriately" by deliberately delaying invoices.

Under the settlement, Rhode Island Energy will credit customers using its storm contingency fund, reducing future storm-related costs.

More: *Rhode Island Current*

SOUTH DAKOTA

Gov. Rhoden Signs Eminent Domain Ban for Carbon Pipelines

Gov. **Larry Rhoden** last week signed a bill banning the use of eminent domain for carbon dioxide pipelines.

The issue has been at the center of a contentious debate over Summit Carbon Solutions' proposed $9 billion carbon capture pipeline. The project would transport carbon dioxide from ethanol plants in five states, including South Dakota, to an underground storage site in North Dakota.

In a letter explaining his decision, Rhoden emphasized his commitment to property rights and framed the bill as a way to restore trust between landowners and developers.

More: *South Dakota Searchlight*

VIRGINIA

Dominion Seeks SCC Approval for Chesterfield Gas-fired Units

Dominion Energy last week said it is seeking State Corporation Commission approval of its $1.47 billion project to install four natural gas-fired generating units at its Chesterfield Power Station.

The four units would generate 944 MW and would run at times of peak demand.

The project would add an average of $1.36 to the residential monthly bill and would vary year-to-year.

More: *Richmond Times-Dispatch*