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# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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By Steve Huntoon

# Holier Than Thou?

By Steve Huntoon

Steve Huntoon

The latest rage in green electricity procurement is hourly matching of carbon-free (green) supply with customer load.[1] The impetus is recognition that the standard practice of annual matching involves non-green generation to balance supply and load throughout the year. This seemingly simple "next frontier"[2] in procurement is anything but simple.

## Some Background

By way of background, let's recall that no consumer physically gets a given supply of electricity. The grid is akin to a giant swimming pool with thousands of hoses dumping water in (generation) and millions of hoses taking water out (consumers). The grid operator is charged with maintaining the water level (balancing). No one physically gets water from a specific water hose.

This is a crude analogy because, among other things, when it comes to electricity, no one gets anything physical at all (matter) — not even electrons, which don't actually move.[3] Instead generators supply electric energy, and that's what consumers use. With me so far?

So when a consumer buys green electricity, it's basically getting a contract commitment of some form that X megawatt-hours of green electricity are generated by the seller, and the seller hasn't sold these green attributes elsewhere.[4]

With annual matching there is total annual green generation equal to total annual consumer load. But because of large differences between generation and load throughout the year, the grid operator has to procure and deliver other generation when that green consumer's load exceeds the green generation. And when green generation exceeds the green consumer's load, the excess is delivered to other consumers (or curtailed).

Now consider this situation with hourly matching instead of annual matching. Every green consumer has to pay the cost of covering its hourly load with green supply. Each hourly load has to be covered from some combination of green generation and storage. The extra green generation to cover peak hours will be under-utilized during other periods, and storage, especially long-duration storage, is hugely expensive, so the cost of this hourly matching is huge.[5]

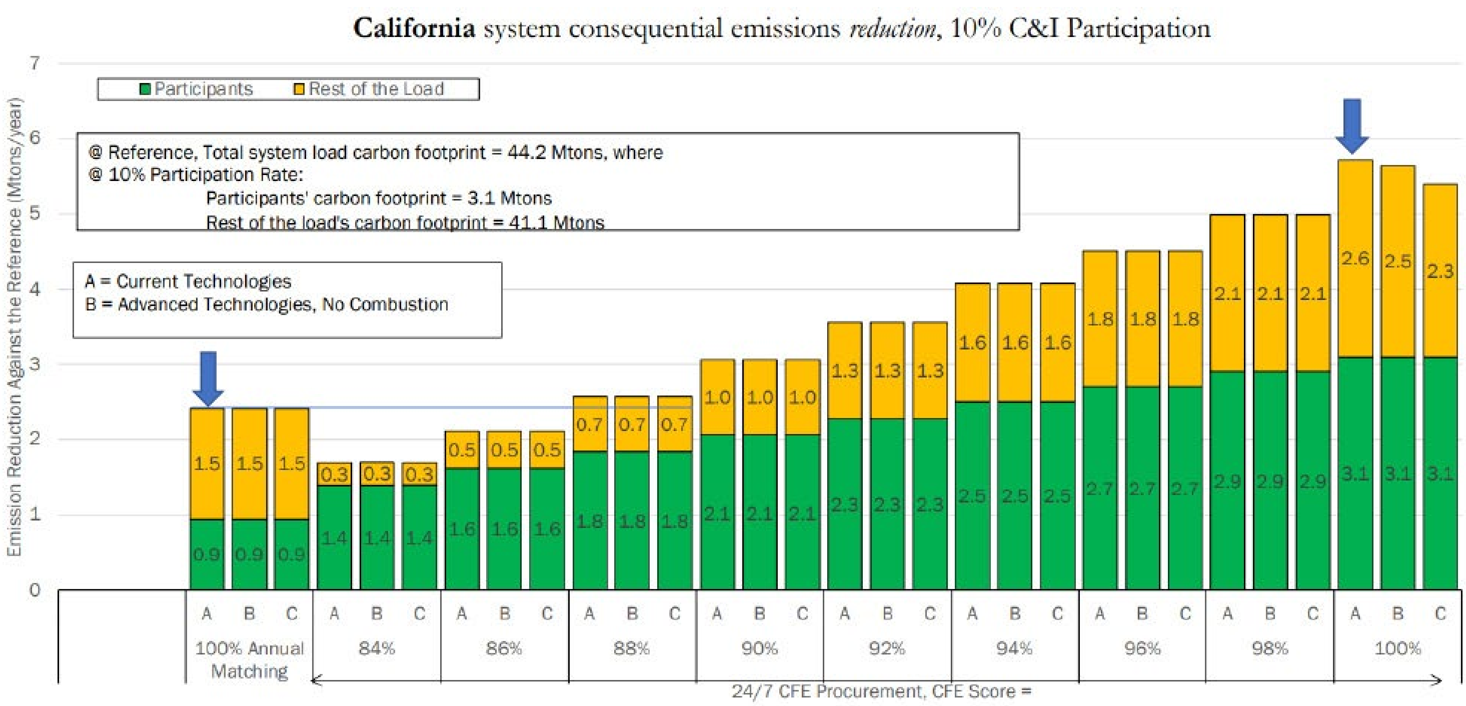
Proponents of this "next frontier" of hourly matching vis-à-vis annual matching say that the former incents much more actual green generation because of the basic phenomenon described above. But there are multiple problems with this vision — as we shall see.

## Hourly Matching Is an Irrational Way to Reduce Emissions

The incremental cost of hourly matching versus annual matching is many times greater than the incremental green generation from hourly matching versus annual matching. The modeling by the proponents of hourly matching shows this.

If you look at this emissions reduction chart for annual matching versus hourly matching, you'll see that annual matching for the sample participation rate in California modeling yields 2.4 million tons/year, compared with 5.7 million tons/year for hourly matching, a ratio of 2.4 to 1.[6]

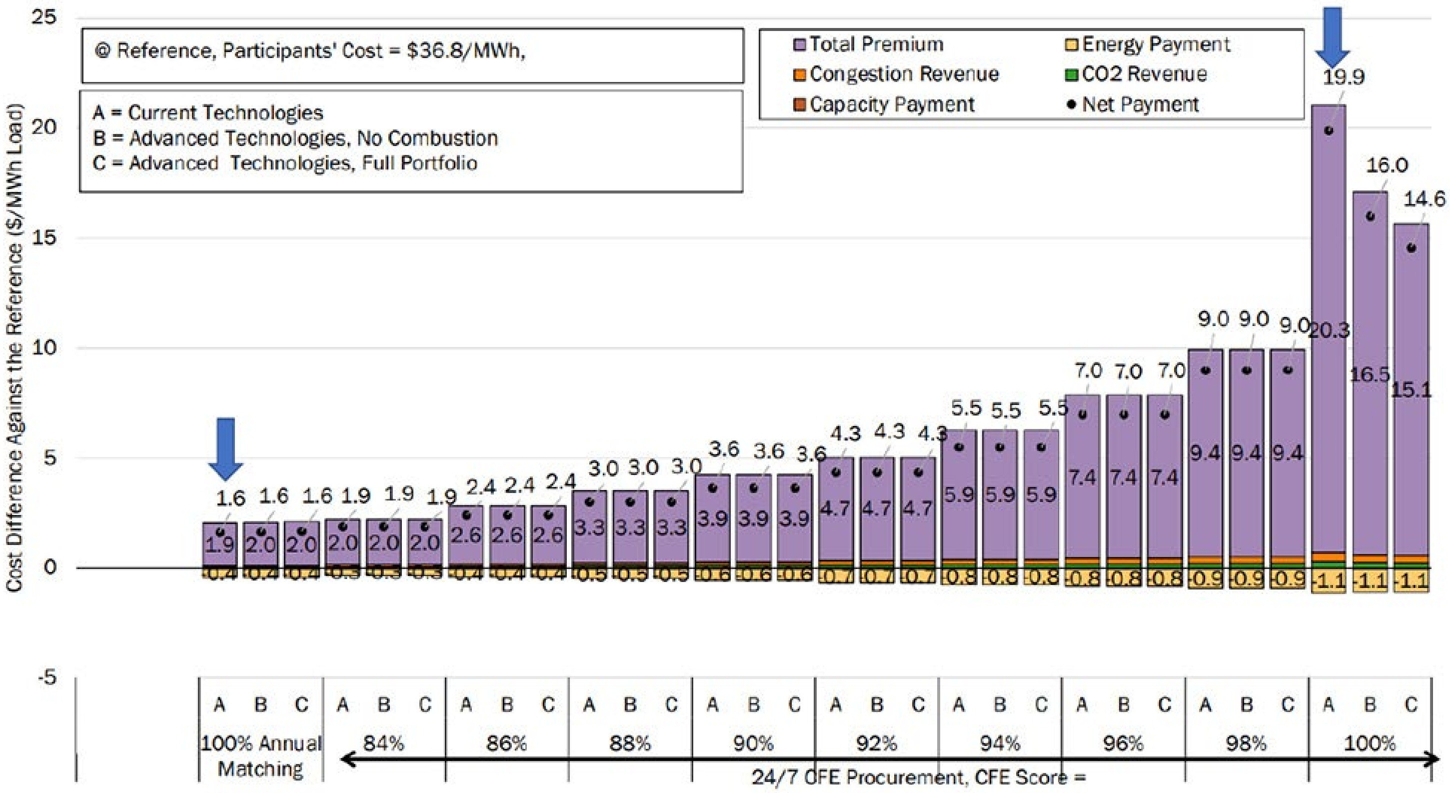
And now if you look at the cost premium chart for annual matching versus hourly matching, you'll see that annual matching has a cost premium of $1.60/MWh, compared with a $19.90/MWh cost premium for hourly matching, a ratio of 12.4 to 1.[7]




Annual matching in California modeling yields 2.4 million tons/year, compared with 5.7 million tons/year for hourly matching – a ratio of 2.4 to 1. | *Jesse D. Jenkins*

# Counterflow

By Steve Huntoon




Annual matching has a cost premium of $1.60/MWh, compared with a $19.90/MWh cost premium for hourly matching, a ratio of 12.4 to 1. | *Jesse D. Jenkins*

So, instead of spending more for hourly matching, the green customer should use extra dollars for more annual green purchases.[8] The same dollar creates much more carbon emission reductions when spent on annual matching instead of hourly matching.

### The Premises for Hourly Matching Are Wrong

Proponents of hourly matching presume that this consistently matches green generation with load. This is not the case for at least three reasons.

An hour is unpredictable, arbitrary and wrong. Proponents of hourly matching presume that within any given hour the green generation is matching the green consumer's load. Of course a typical consumer's load fluctuates widely; can a given consumer accurately forecast its load hour-by-hour and then communicate that to a generator such that the generator tracks that forecast with its output?

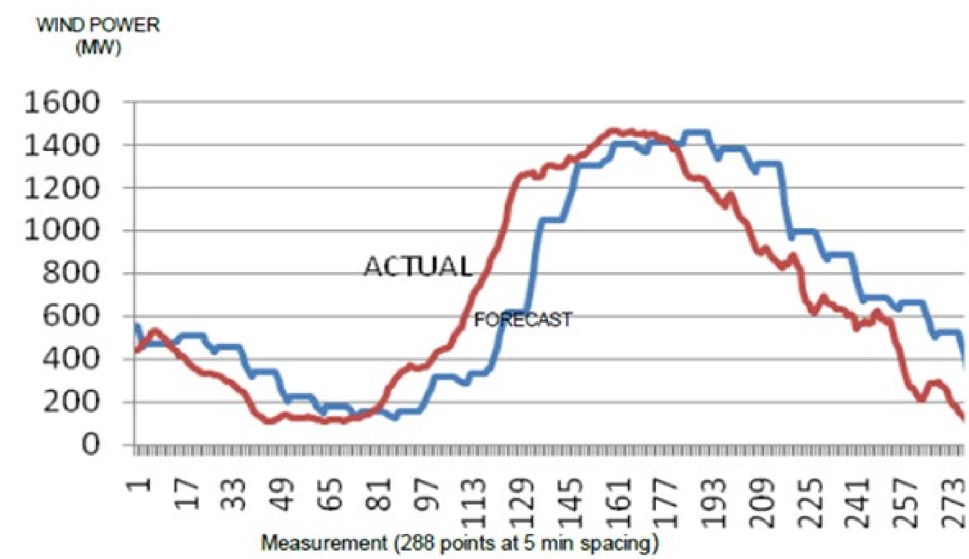
And even where the consumer's load tends to be flat (such as at a data center), green generation is not. This is illustrated by wind generation data for a typical balancing authority (region) for five-minute intervals.[9] You can see that wind generation varies greatly among 12 five-minute intervals comprising an hour.

If hourly matching is used, load will be matched to the average of the 12 five-minute intervals. During any given five-minute interval when load exceeds wind generation, other resources will be dispatched to cover the difference. And, similarly, when load is less than wind generation, the excess will be delivered to other consumers.

Just like annual matching!

### Location, Location, Location

To further complicate matters there is the




Wind power forecast and actual wind power values, for one day, in five-minute intervals | *Pacific Northwest National Laboratory*

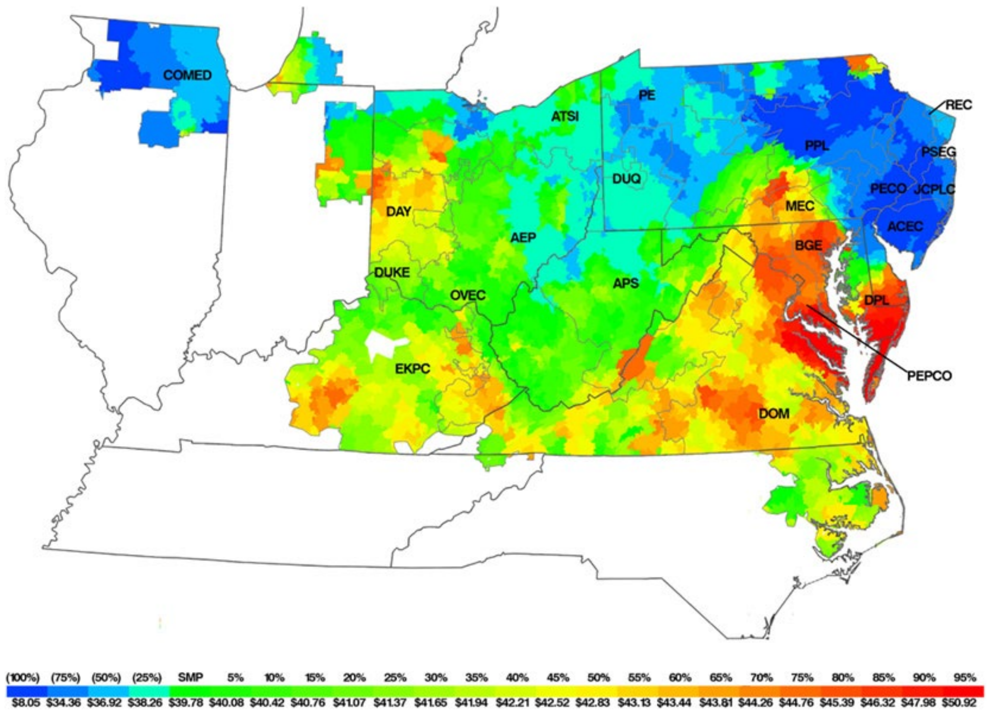
# Counterflow

By Steve Huntoon

stumbling block of transmission constraints throughout the grid. In PJM for example, there are thousands of such constraints which, by definition, keep lower-cost energy from reaching load (aka "congestion"). This happens all the time all over PJM and is indicated by higher energy prices in constrained areas.[10] This map of varying energy prices in PJM illustrates the phenomenon.[11]

Now let's consider a consumer inside a transmission-constrained area for a given hour. If the consumer's green supply is on the other side of the constraint, then that green supply does not supply that consumer. Other generators, inside the transmission-constrained area, are being dispatched to supply that consumer (and other load within the constrained area).

The proponents of hourly matching say that generators and consumers will be grouped together by "the same electricity grid region,"[12] thus ignoring these transmission constraints.




PJM real-time load-weighted average LMP for 2021 | *Monitoring Analytics*

## Marginal Emissions

If things weren't complicated enough, unless and until all non-green resources are eliminated from the grid, there is the nagging problem of marginal emissions. These come from the last (most expensive) resources dispatched to meet demand at any given point in time. And they typically would be fossil fuel resources because of their higher variable cost than green resources.

If we take a consumer that has an hourly matching supply arrangement, it can point to a matching green supply for its hourly load. But the sheer presence of its hourly load could cause the marginal resource to be fossil fuel instead of green. Now this consumer could argue that this is not the right "but for" test because without its load it wouldn't be providing the green supply, and therefore the marginal fuel would be fossil fuel in any event.

But then again, once the green generation exists it would run regardless of whether it's part of the supply committed to that consumer.

So whether hourly matching always causes zero emissions (putting aside the arbitrary hour and transmission constraint issues discussed above) is somewhat of a metaphysical question.

## Wrapping Up

Hourly matching is wasteful, and the premises for it are wrong. The climate challenge is tough enough without wasting money. ■

[1] An entire conference was devoted to this and related subjects in December, http://www.raabassociates.org/main/roundtable.asp?sel=166. Only proponents — no skeptics — were on the panels. There is a federal executive order that requires 50% of federal electricity by 2030 to be "24/7 carbon pollution-free electricity," https://www.whitehouse.gov/briefing-room/presidential-actions/2021/12/08/executive-order-on-catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability/, section 102(i).

[2] http://www.raabassociates.org/Articles/Jenkins%20Presentation%2012.9.22.pdf (hereafter "Jenkins Presentation").

[3] "Energy is transmitted, not electrons. Energy transmission is accomplished through the propagation of an electromagnetic wave. The electrons merely oscillate in place, but the energy — the electromagnetic wave — moves at the speed of light. The energized electrons making the lightbulb in a house glow are not the same electrons that were induced to oscillate in the generator back at the power plant." -Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists, at 2, New York v. FERC, 535 U.S. 1 (2001), https://www.findlawimages.com/efile/supreme/briefs/00-568/00-568.mer.ami.engineers.pdf

[4] The green contract commitment can be in the form of Renewable Energy Certificates (RECs) or a power purchase agreement with a green generator. More here, https://www.ftc.gov/sites/default/files/attachments/press-releases/ftc-issues-revised-green-guides/greenguides.pdf, section 260.15.

[5] For example, RMI presents study data indicating that low hourly matching (0-10%) costs around $50/MWh while higher hourly matching (70-80%) costs more than $200/MWh — and that's not close to full hourly matching. http://www.raabassociates.org/Articles/Final%20Dyson%20Presentation%2012.9.22.pdf, slide 10.

[6] Jenkins Presentation, slide 8, with annual matching and hourly matching under current technologies noted by arrows.

[7] Jenkins Presentation, slide 10, with annual matching and hourly matching under current technologies noted by arrows.

[8] This can be done by simply purchasing more RECs, or by over-procurement in a PPA with sale of the excess overload into the grid.

[9] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-19229.pdf, Figure 6.1 on page 6.4.

[10] For exhaustive detail on this phenomenon, please see the most recent State of the Market report here, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec11.pdf

[11] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec3.pdf, Figure 3-44 on page 174. A map showing zonal prices in real time is on the PJM home page.

[12] http://www.raabassociates.org/Articles/Jenkins%20Presentation%2012.9.22.pdf, slide 4; 24x7 Carbon-Free Energy: Methodologies and Metrics (gstatic.com), slides 6-9.

## FERC/Federal News

# Clements: States Should not Wait on FERC for Transmission Planning

### *State Energy Offices Urged to 'Close the Gap' Between Tx, Distribution Planning*

*By K Kaufmann*


FERC Commissioner Allison Clements | © *RTO Insider LLC*

WASHINGTON — State energy offices have a key role to play in transmission planning, and they can and should take action even before FERC finalizes its rules on regional planning and cost allocation, Commissioner Allison Clements told a packed ballroom at the National Association of State Energy Officials' (NASEO) Winter Policy Summit on Wednesday.

"There's a feeling around Washington, perhaps, that FERC's got this under control; we're going through this transition," Clements said. "FERC can cross every 't' and dot every 'i' [for] the perfect transmission planning and cost allocation rule, but if the states [haven't] bought in and if the rest of the pieces related to getting transmission done, from cost allocation to siting, aren't considered together, we won't get it done. …

"You have an opportunity to decide by being proactive in your state in these federal jurisdictional planning processes how you want this to play out," she said.

State regulators and utilities are generally seen as having the primary power for transmission planning at the state level, but Clements and others at the conference argued that energy offices can act as hubs for bringing together public, private and community stakeholders, as well as fostering regional and cross-state collaborations. Such state-level efforts could include not only planning for new transmission, but also upgrading lines with grid-enhancing technologies (GETs).

"Transmission is the No. 1 solution to the reliability, costs and security of our system. That is the reality today," Clements said. "The other reality is that money is going to be spent. … And the question is how are we going to direct that money? How can we make that money be spent well, so that customers 10 years from now, 15 years from now, 20 years from now are not left holding the bag on a system that is under-matched for the challenges at hand?"

The development of transmission for offshore wind is ripe for regional planning, Clements said, pointing to the efforts of five New England states to secure up to $250 million in federal funding from the Infrastructure Investment and Jobs Act. (See *New England States Group up to Push for Federal Transmission Funding*.)

"Current transmission system planning wasn't designed to create a whole new grid, which is effectively what a regional offshore wind system is," she said.

The first offshore wind projects now under development are being laid out with radial lines connecting them to onshore substations, which is "not the most cost-effective way to get significant capital transition investment done," Clements said.

"If we start as a group of willing states, whether it be offshore or onshore in your region, and start talking about what a robust set of investments look like 10 years forward, you have the opportunity to not slow down the current procurements, which your states are very focused on, but to have a parallel track to be thinking forward about what you want that to look like," she said.

Clements also encouraged state energy offices to actively promote the use of GETs — such as dynamic line ratings and advanced conductors — to increase the capacity of existing lines while saving millions for grid operators and customers.

Citing a *2021 report* from the Brattle Group, for example, Clements said a combination of GETS could double the amount of renewable energy that could be interconnected on existing lines.

While some projects have been successfully completed, GETs are not being widely adopted, Clements said, first because of misaligned incentives. "Why would a transmission owner or a utility want to make an investment that would actually decrease its need to increase its rate base?" she said.

A bigger challenge, however, is the jurisdictional split between FERC and the states, and transmission and distribution, Clements said. "FERC usually focuses on the bigger transmission investments; states are usually focused on the distribution system," she said. "We have to close that gap, and I think it is incumbent on all of us to talk to our regulators about the opportunity for grid-enhancing technologies; to ask our utilities about it; to put a little friendly pressure on; to say, 'What are you doing on this?'"

### Spurring Private Investment

Estimates vary of just how much new transmission the U.S. will need to achieve a carbon-free grid by 2035 and a net-zero economy by

# FERC/Federal News

2050. A much cited *2021 study* from Princeton University called for a threefold increase in transmission capacity, while a *recent study* from the National Renewable Energy Laboratory said the amount of new transmission needed will depend on the generation mix, setting a range of 1.3 to 2.9 times current capacity.

The IIJA includes $10.5 billion for a new Grid Resilience and Innovation Partnerships program, and Maria Robinson, director of the Department of Energy's Grid Deployment Office, said the first round of funding for the program, totaling $3.8 billion, had drawn hundreds of concept papers.

"What excites me most about what's going on here is that there are lots of really phenomenal ideas for rapid resilience … whether that is coming from utilities directly, or munis or co-ops, you have lots of terrific ideas on how they want to modernize," Robinson said.

Echoing Clements, Robinson sees state energy offices as being able to extend the reach of federal funding to look "at how we continue to use this momentum to spur greater investments moving forward from the private sector as well … to ensure we're getting the best bang for our buck." Ongoing collaboration between DOE and state energy offices is an integral part of Robinson's vision for "figuring out where the needs are."

Maria Robinson, DOE | © *RTO Insider LLC*

Robinson acknowledged some of the frustrations raised by the funding limitations, specifically that some of the IIJA funds for grid resilience cannot, at this time, be used to include generation from microgrid projects. "It's just terrible," she said. "We are working really hard to figure out if there are other places where we might be able to find that money" for microgrids to be included in grid resilience projects, she said.

## Convening, Informing, Engaging

Karen Wayland, CEO of the Gridwise Alliance, sees the blurring of lines between state and federal jurisdiction as a result of the higher profile states are taking in setting their own clean energy targets. As a result, she said, state energy offices need to be actively engaged with their governors, legislatures and grid operators.

"We're trying to design a system to meet state and federal goals, and so that means that the states have to be involved in the infrastructure that's necessary to be that platform to meet their decarbonization and their security goals," Wayland said in an interview with *RTO Insider*. "They have a really important role to play in convening the relevant stakeholders at the state and local level to kind of guide them to an understanding of the goals that that expanded transmission would address."

State energy offices also "have a big role to play" in coordinating stakeholder discussions on high-voltage transmission lines being planned to connect nodes within their states, to help determine "whether and how and where a transmission line will be built."

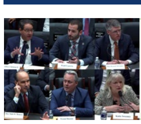
David Terry, NASEO | © *RTO Insider LLC*

NASEO President David Terry sees state energy offices being able to take a broader view of energy market evolution than state regulators typically can because of the statutory limitations of their work.

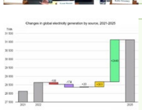
State energy offices can "work with local communities on behalf of your governor, on behalf your legislature, to inform them of why the state is going in a certain direction with their energy activities," Terry said. "Why a transmission line may be important; what's the value to them … what's the long-term benefit. For the average voter or consumer, this is not exactly top of mind."

While "kind of soft and a little bit amorphous," Terry said, the stakeholder engagement and public education roles of energy offices do have an impact on state-level decision making. They can "look across all of these new demand[-and-]supply issues … and they can take in some of those concerns that private sector industry has," he said. "I think that informs the process. Nothing will make it easy, but it informs it so at least the best decisions can be made." ■

## National/Federal news from our other channels



*New House GOP Majority Moves to Aid Fossil Fuel Sector* — NetZero Insider



*IEA Renewables to Provide 90% of World's New Power Generation* — NetZero Insider

*NERC Pushes Alternate IBR Standards Timeline in Response to NOPR* — ERO Insider

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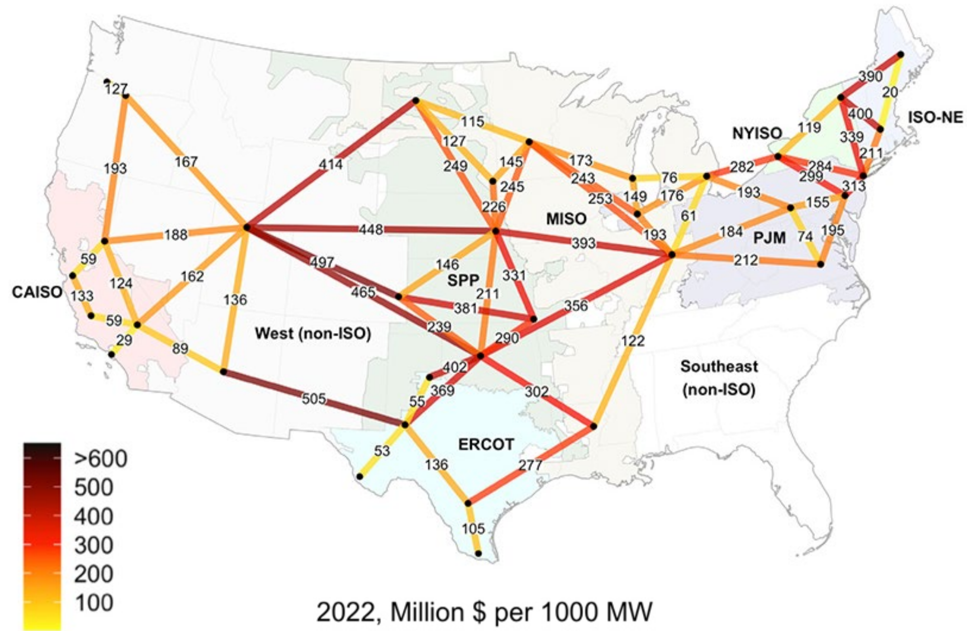
## FERC/Federal News

# Lawrence Berkeley Lab Sees New Transmission Value Spike in 2022

*By James Downing*




A map showing the hypothetical transmission lines LBNL studied. | *Lawrence Berkeley National Laboratory*

The Lawrence Berkeley National Laboratory on Feb. 7 released *updated data* showing that the savings for new electric transmission lines were higher last year than at any point in the last decade.

"Generally high electricity prices coupled with extreme weather events and other factors helped drive the high value for transmission," LBNL said in a fact sheet on its findings.

The lab looked at congestion values and found that building major new lines between important power trading hubs would lead to significant savings. Congestion is correlated with the national average of wholesale electricity prices.

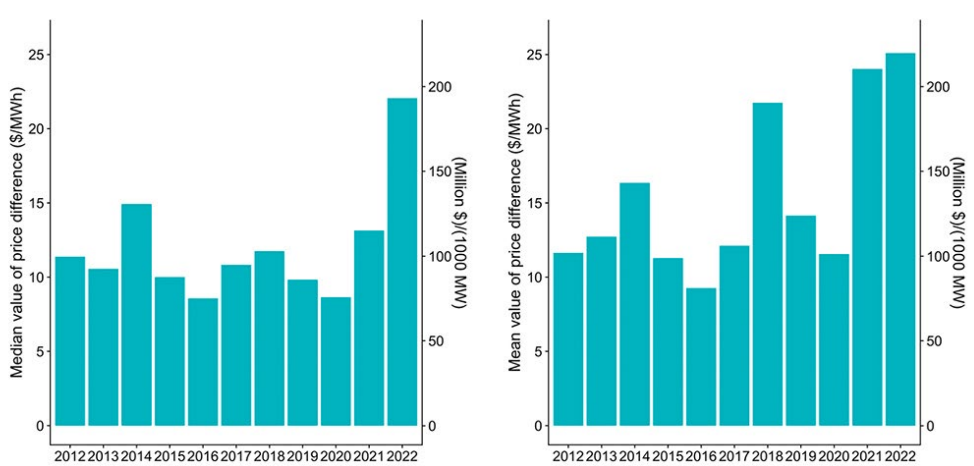
"Extreme conditions and high-value periods have an outsized role in driving this value, though named extreme weather events oftentimes do not play as large a role as more normal but infrequent conditions, such as infrastructure outages or demand forecast misses," LBNL said.

The report found that interregional transmission lines would offer the largest values, as most — but not all — the transmission links with a value above $200 million per 1,000 MW were interregional. Smaller regional lines had a significant valley, with many ranging from $100 million to $200 million per 1,000 MW.

LBNL looked into 64 hypothetical transmission projects, and their mean value was $220 million per 1,000 MW, or $25/MWh, while the median value was $193 million per 1,000 MW, or $22/MWh. Both the mean and median prices were higher than earlier years that LBNL studied.

The median value was significantly higher than in any other year, which indicates that higher transmission value in 2022 was a broad phenomenon across most of the country. That suggests a national cause, such as higher power prices, were behind the rise in transmission value.

LBNL saw higher mean values in 2018 and 2021, which indicates that certain events can drive extremely high transmission value in isolated regions. ERCOT and SPP saw transmission values spike in 2021 because of the February winter storm, the report said.




A chart showing the mean and median values of LBNL's hypothetical lines over the past decade | *Lawrence Berkeley National Laboratory*

Transmission's value is tied to high demand/high-priced hours, but the higher overall prices last year made that less true than some years. Some 50% of the lines' studied value was from just 10% of hours and 37% was from only 5% of the hours in 2022, but from 2012 to 2021, a typical transmission line derived 50% of its value from just 5% of hours.

The final week of 2022 came with another major winter storm, which showed the role of transmission in helping to manage periods of grid stress as the average transmission link derived 7% of its annual value over that week. The total annual value of transmission lines was much more tied to the winter storm in PJM, MISO and the Northeast, where the storm provided 10 to 22% of transmission lines' values.

The report noted that if all the hypothetical lines it studied were actually built, they would have diminishing returns. Because wholesale power markets use marginal pricing, the transmission value metric LBNL calculated represents the value of the next unit of transmission.

The lines studied would be impacted by a saturation effect as additional construction brings down their value, but LBNL said that the links connect "hub" pricing nodes that represent prices over a region and might not be as sensitive to saturation effects as a more localized pocket of demand. ■

FERC/Federal News

# ACORE Report: Storm Showed How More Tx Could Yield Benefits

## *Glick, Panel Debate 'Bigger Grid' to Address Extreme Weather*

*By Tom Kleckner*

Former FERC Chair Richard Glick said Wednesday that an industry report on the estimated value of additional transmission during December's Winter Storm Elliott only underscores what many already know: Transmission capacity makes a big difference.

It can also produce savings.

"When you reduce congestion, you're able to bring in less costly power from other regions, and that has a big impact, certainly on prices," Glick said Wednesday during a webinar focused on the report. "That's a big deal because when we have these extreme weather events, we know prices are at their highest sometimes. But secondly, transmission also helps with grid resilience and reliability. Another reason is [regions] might not be experiencing that same weather at the same time. … Empower[ing] other regions is a big positive."

Glick brought up ERCOT's problems importing power from other regional operators during the deadly 2021 Winter Storm Uri because of its lack of interconnections with its neighbors. Hundreds of Texans died without power during that storm. At the same time, MISO successfully wheeled power from PJM to SPP to help the latter grid avoid Texas' woes.

"Transmission support not only from a consumer perspective, but also for keeping the lights on," he said.

According to a *report* released Wednesday by the American Council on Renewable Energy (ACORE), "modest investments" in some regions' interregional transmission capacity would have saved electricity customers nearly $100 million during December's five-day storm.

ACORE, which hosted the webinar, said expanding transmission ties by 1 GW between regions would have generated significant cost savings for consumers and reduced outages during the storm. It said that Duke Energy's Carolinas region and the Tennessee Valley Authority would have yielded savings of $85 million and $95 million, respectively, had they been able to import enough power to prevent rolling blackouts.

### 'Bigger than the Weather'

The report studied transmission benefits by comparing LMPs within RTOs and ISOs and at

Former FERC Chairman Richard Glick | *© RTO Insider LLC*

interfaces with non-organized market areas during each hour of the Dec. 22-26 storm. The analysis conservatively used hourly average LMPs instead of prices at five-minute intervals, as current practices for scheduling transactions between regions include market seam inefficiencies that limit the ability to use transfers to address short-term fluctuations in price.

"Making the grid bigger than the weather is the key to making our power system more resilient," said Michael Goggin, a vice president at Grid Strategies and the report's author. "Basically, the solution here is making the grid bigger than the weather. If the grid is bigger than that event, that allows you to get that demand diversity because [regions are] not all peaking at the same time. You could bring in generation from areas where the gas supply wasn't interrupted or the generators didn't have failures."

Goggin said a bigger grid is also the solution to higher penetrations of wind and solar, with the side benefit of full resource adequacy.

"If you go across a large enough area, particularly with wind, the correlation between any two wind plants drops to almost zero. They're just experiencing different weather at different times … kind of mitigating and canceling out the variability of wind," he said. "More importantly, you get the resource adequacy benefit. If it's not windy here, it's going to be windy somewhere else, and having the transmission allows you to move that power between those areas."

ClearPath CEO Rich Powell agreed. He said the country will need "tremendously" more wires and pipes — for natural gas, hydrogen, carbon-capture — as part of an enabling infrastructure to build a net-zero economy by 2050.

"My guess is that we're going to need a lot of renewables built on public lands further west just because we're seeing so much opposition growing, especially in the middle of the country that's already very dense on wind," he said. "My suspicion is we're going to have to build more of that further west on public lands, which itself is going to imply more long-distance transmission."

Powell is hopeful early hearings in Congress on permitting reform proposals might be a sign of optimistic developments but allowed that "we're at the beginning of that journey."

ACORE CEO Greg Wetstone lamented the loss of an investment tax credit for high-voltage transmission, a victim, he said, during final negotiations over the Inflation Recovery Act (IRA).

"That is the one piece that is really important and ended up on the cutting room floor," he said. "That kind of incentive would be helpful … [in] getting the investment we need to better connect the grid."

Wetstone said the tax credit is one of three areas that have seen real progress in the last two years but aren't "over the finish line." He listed FERC's proposal for more proactive transmission planning addressing extreme weather and siting and permitting language that a congressional parliamentarian scratched from the IRA under budget reconciliation rules.

"We need more help, more clarity in order to get these lines built," he said. "We're potentially in the game with this Congress to get something done in siting and permitting."

### 'Geographic Opportunity'

Glick reminded his fellow panelists that the commission's joint task force with state regulators has been focused on interregional transmission capacity. The group holds its *sixth meeting* this Wednesday.

"One thing we kept them coming back to is the need for more interregional transfer capacity or transmission capacity," he said. "Is there a need for some sort of minimum requirements

# FERC/Federal News

between regions or something like that?"

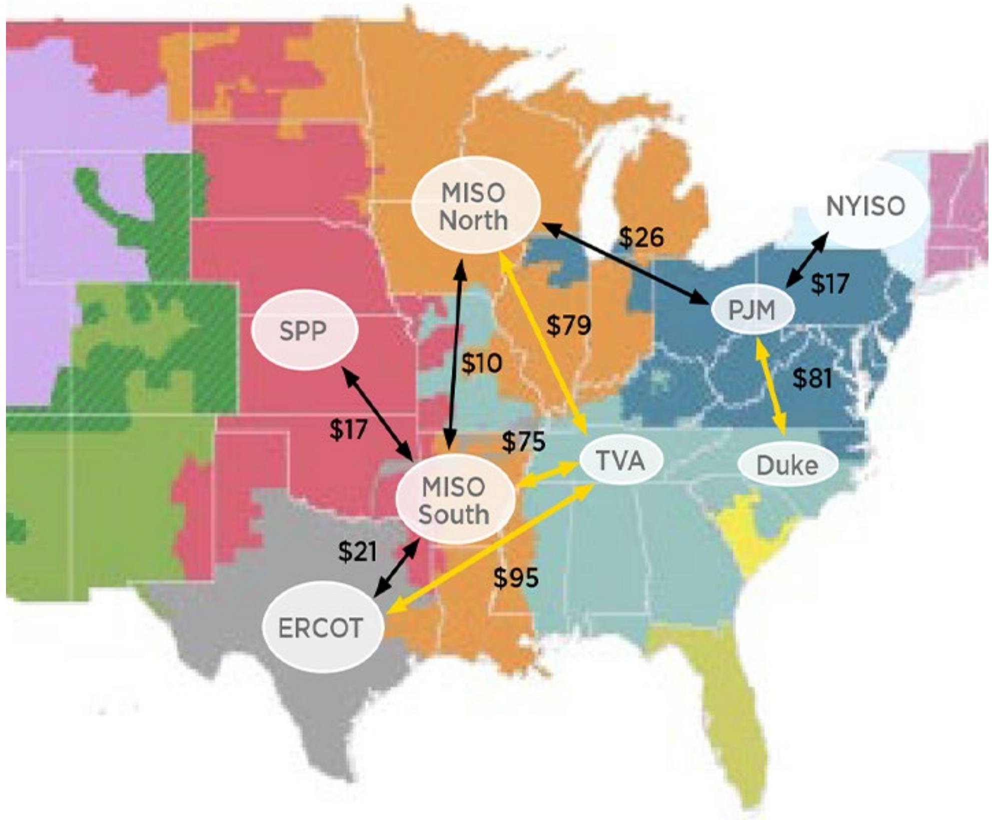
"Interregional transmission continues to be a key missing ingredient for U.S. grid reliability in the face of increasingly frequent extreme weather events," Wetstone said, calling for action on proposed "pro-transmission" policies and reforms in Congress and at FERC.

"It has been exceptionally difficult, if not impossible, to develop interregional transmission under the current planning processes and related rules," he added.

"There's quite a bit of interest among not only FERC commissioners but also state commissioners about moving forward," Glick said. "It's not easy to figure out who decides what gets built and who pays for all those issues, but I'm optimistic that you're going to eventually see something."

"The weather is getting bigger and bigger, and the grid is not keeping up with it," former FERC and Texas commission staffer Alison Silverstein said. "We are seeing patterns where the wind goes bonkers as the front comes in, and then it dies off as the front is leaving. Being able to play the geographic opportunity is extremely valuable. We need to be able to build diversity, and we need to be able to build customer survival while all these dynamics and expansions are taking place. So it's an extraordinary challenge and opportunity."

That may come at the RTO/ISO level. MISO said that while it didn't have the chance to fully review the report, the findings appear to support the grid operator's efforts to develop more transmission to maintain reliability and manage the uncertainty and volatility of extreme weather events. The RTO pointed to its work on its four planned long-range transmission portfolios, noting that the benefits from the first tranche of projects are greater than the $10 billion costs.




The benefits of 1-GW expansion in transmission links between grid operators (millions of dollars) | *ACORE*

In an email to *RTO Insider*, spokesperson Brandon Morris said MISO is a strong supporter of interregional transmission planning and "has worked diligently to improve our operations and planning with our neighbors."

"Strong interconnections are foundational for the grid of the future," he said. December's winter storm "was a recent example of the benefits of interregional transfer capacity — at times during that event we were importing power from our neighbors, and at other times we were exporting power to support them."

PJM and SPP declined to comment on the ACORE study. An SPP spokesperson said staff is currently evaluating its response to the latest winter storm to understand its impacts and how they can be mitigated in the future. ■

# Lawmaker Introduces Bill to Turn CAISO into RTO

*By Hudson Sangree*

SACRAMENTO, Calif. — A key state lawmaker introduced a bill Wednesday that could eventually transform CAISO into a regional transmission organization with an independent governing body, including members from other Western states.

*Assembly Bill 538*, by Assemblymember Christopher Holden, would allow CAISO to develop a governance proposal to reach that end, requiring approval from the California Energy Commission and the state legislature. Under the bill, a Western states committee would have an equal number of representatives from states whose transmission owners participate in CAISO. The bill says the committee would "provide guidance" to the ISO on "all matters of interest to more than one state," but the body's exact role — including its part in selecting board members — remained unclear Wednesday.

"Centralizing dispatch operations and transmission planning with the rest of the region would significantly enhance electrical reliability and affordability for California households," Holden, chair of the Assembly Appropriations Committee, said in a statement. "California could go it alone, but then we would be a proverbial energy island. The bottom line is California can reduce cost, ensure we keep the lights on and importantly, achieve our clean energy goals by collaborating with other Western states."

Holden's prior efforts in 2017/18, when he chaired the Assembly Utilities and Energy Committee, failed to persuade enough of his fellow lawmakers to relinquish control of CAISO's Board of Governors, whose five members are appointed by the California governor and confirmed by the state Senate.

Circumstances have changed since then, with strained supply in the West during extreme weather, especially in California. More states, cities and utilities have adopted 100% clean energy goals like California's, requiring new transmission to move wind and solar power long distances. And two states, Nevada and Colorado, enacted requirements that their major transmission owners join RTOs by 2030.

In addition, CAISO faces competition from SPP, which plans to establish its own Western RTO, and from the Western Power Pool, whose Western Resource Adequacy Program could be a springboard to an RTO.

Last year Holden won unanimous passage of Assembly Concurrent Resolution 188, which asked CAISO to prepare a report for the state legislature summarizing studies of the benefits of regional market participation as a way to restart regionalization discussions.

The report is due to lawmakers by the end of February. A draft report, prepared by the National Renewable Energy Laboratory, cited a range of studies that show significant benefits for California and the West in terms of cost savings, grid reliability, transmission planning and meeting clean-energy goals. (See *CAISO Issues Report on Western Regionalization Studies*.)

In recent weeks, the movement toward greater regionalization, and calls for one or more RTOs in the West, have grown.

A plan by CAISO to add a day-ahead market to its Western Energy Imbalance Market cleared the Board of Governors and the WEIM Governing Body on Feb. 1. (See *CAISO Approves Day-ahead Market for Western EIM*.)

On Feb. 6, a group that calls itself Lights on California, said it planned to advocate for California to be part of an RTO and for CAISO to become a regional organization. The coalition's *members* include national trade groups Advanced Energy United and the Solar Energy Industries Association, environmental organizations Natural Resources Defense Council and Environmental Defense Fund, and the California Chamber of Commerce. (See *New Coalition Aims for California to be in RTO*.)

## Trust Needed

Advanced Energy United reacted to Holden's bill introduction Wednesday with a statement that said, "We applaud Assemblymember Holden for his leadership in jumpstarting a thoughtful and action-oriented conversation around regional grid collaboration. California should work with the rest of the West to strengthen energy reliability, affordability and accelerate our progress toward 100% clean energy.

"This is the moment for action. Today, 85% of electricity demand in the West is under a 100% clean goal," it said. "California should not miss this opportunity to lead the way."

Vijay Satyal, deputy director of regional energy markets for Western Resource Advocates, said in an interview that the bill represents a "clearer understanding" of the interconnected West.


Assemblymember Christopher Holden, seen here speaking on the Assembly floor, will have to convince his fellow lawmakers that CAISO should become an RTO. | *California Assembly*

"It is connected by resources; it is connected for reliability reasons; and a centralized market would enable more resource diversity, bring in more clean energy resources, and strengthen grid reliability," Satyal said.

The declining cost of renewable power and increasing demand for it means "you are seeing growing momentum to recognize that we need a larger connected market," he said.

Passing Holden's bill during the two-year legislative session that began in December will require greater trust among Western states, he said. Prior attempts failed because California did not want to cede partial control of CAISO, and other states, especially those in the more-conservative interior West, were unwilling to let California control a multistate transmission organization.

"What hopefully will change this time is trust," Satyal said. "That trust has to be built with a new market structure."

CAISO declined to comment, saying it had not seen the bill in print yet. Previously CEO Elliot Mainzer said, "There's a strengthened recognition of the need to work together in the West and the benefits of working together." CAISO, he said, stood ready to work with Holden on his push for "broader governance reform." ■

## CAISO/West News

# Natural Gas Prices Add $4B to CAISO Electricity Costs

### *Newsom Urges FERC to Investigate for Market Manipulation*

*By Hudson Sangree*

Soaring natural gas prices drove up wholesale electricity costs in the CAISO energy market by roughly $4 billion in December and January, making it one of the more expensive periods in recent years, an ISO report said last week.

About $3 billion of that amount came in December, when natural gas prices in California far outpaced the national benchmark Henry Hub in Louisiana. On Dec. 21, for example, spot prices at Henry Hub averaged $6.14/MMBtu, while those in California reached $53.59/MMBtu, nearly nine times more, the U.S. Energy Information Administration reported.

High natural gas prices impacted large swaths of the West in December, including the Desert Southwest and the Pacific Northwest.

"Next-day natural gas prices for Western hubs reached a maximum value of about $57/MMBtu on Dec. 22," a day when CAISO's wholesale costs surged toward $300 million, far beyond its standard cost of $50 million, the CAISO *report* said.

"Prices for other Western hubs traded at similarly elevated levels across the month of December … [while] Henry Hub prices remained comparatively low," it said.

In the fourth quarter of 2022, total electricity costs in CAISO reached $7.4 billion, just short of the third quarter's $7.6 billion total during a severe heat wave that brought CAISO to the verge of ordering rolling blackouts Sept. 6 and pushed electricity prices past $2,000/MWh. (See *CAISO Reports on Summer Heat Wave Performance*.)

The third quarter costs reflected "summer conditions where record-high demand levels were settled at relatively higher prices given the tight supply conditions," the report said. "The cost of fourth quarter of 2022 came fairly close to the same level of the third quarter, at about $7.4 billion, even though electric demand was lower."

"This is a twofold and threefold increase relative to the fourth quarters of 2021 and 2020, respectively," it said.

The sudden and largely unexplained jump in energy prices in California and the West led Gov. Gavin Newsom to urge FERC to act. In a *letter* Feb. 6 to FERC Chair Willie Phillips, Newsom asked the commission to "immediately focus its investigatory resources on assessing whether market manipulation, anticompetitive behavior or other anomalous activities are driving these ongoing elevated prices in the Western gas markets."

Wholesale natural gas prices directly affect electricity costs because California relies heavily on gas-fired power plants, which often act as the marginal unit setting the price for all units clearing CAISO's day-ahead and real-time markets. The gas costs are passed on to ratepayers by the state's investor-owned utilities, doubling and tripling bills for millions of customers, especially in Southern California.

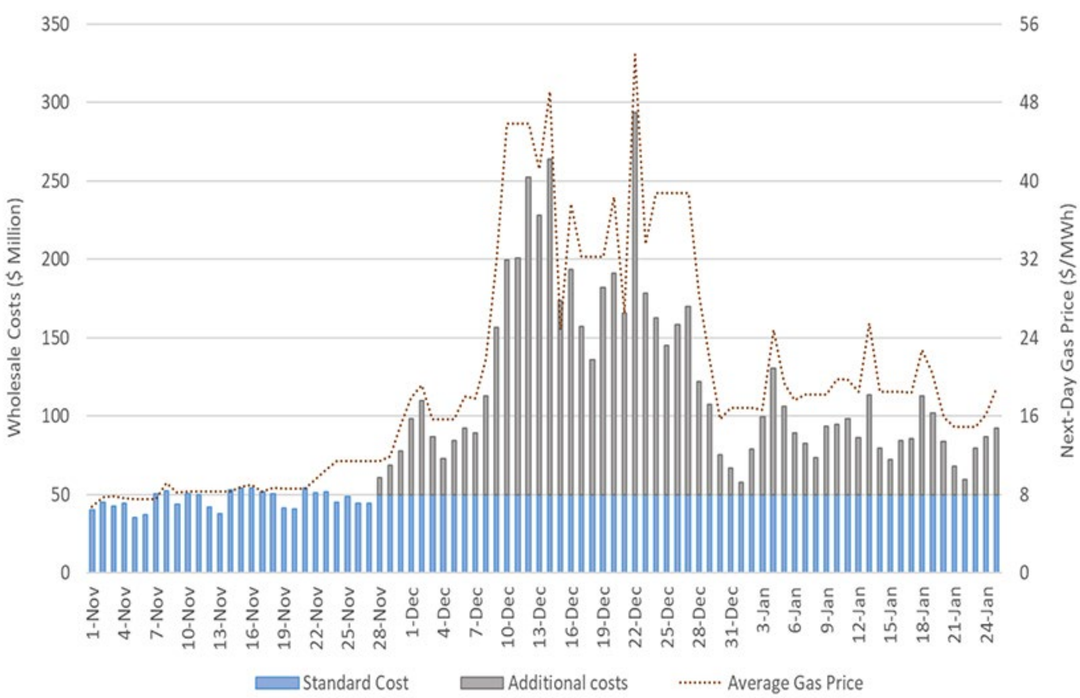
"California's residential customers are, consequentially, suffering the economic burden of extreme and unexpectedly high gas and electric utility bills," Newsom wrote.

The California Public Utilities Commission, state Energy Commission and CAISO held a joint *meeting* Feb. 7 to try to understand the factors that led to the extraordinary price hikes. Market analysts and utilities weighed in, citing conditions such as an El Paso Natural Gas pipeline that exploded in Arizona in August 2021, impacting one supply line to California, and CPUC limits on storage at Southern California Gas Company's Aliso Canyon, where a massive methane leak occurred in October 2015.

A cold snap in December increased heating demand from residential customers in California and across the West, panelists said.

In his letter to FERC, Newsom said the cold weather certainly "exacerbated" the gas price increases but lower-than-normal temperatures and other "known factors cannot explain the extent and longevity of the price spike," which began in late November and lasted through January.

"It is clear that the root causes of these extraordinary prices warrant further examination," he said. ■




CAISO's additional costs for wholesale electricity soared from late November through January, reflecting high natural gas prices. | *CAISO*

## CAISO/West News

# FERC Approves Western Resource Adequacy Program

*By Hudson Sangree*

FERC on Friday approved the tariff for the Western Power Pool's Western Resource Adequacy Program, a groundbreaking reliability effort covering much of the Western Interconnection that is meant to ensure members have sufficient resources to meet summer and winter peak demands (*ER22-2762*).

The commission's approval means the WRAP can move forward with its plans to begin a binding phase of the program by 2025, including penalties for members that fail to meet their obligations.

"Through increased coordination, we find that the WRAP has the potential to enhance resource adequacy planning, provide for the benchmarking of resource adequacy standards and more effectively encourage the use of Western regional resource diversity compared to the status quo," FERC said in its decision.

At least 11 utilities had committed by December to joining the binding iteration of the WRAP. The nonbinding phase of the program has 26 participants, many of whom are expected to move into the next phase. (See *Western RA Program Secures First 'Binding' Phase Participants*.)

WPP has been developing the WRAP since 2020. The program is meant to address concerns that Northwest utilities had been increasingly and unknowingly drawing on the same shrinking pool of reliability resources. But interest in the effort spread quickly to other areas of the West.

WPP selected SPP to develop and operate the technical aspects of the program, providing the market's forward-showing functions, modeling and system analytics, and real-time operations.

In a move that signified its expanding reach across the Western Interconnection, the Northwest Power Pool rebranded itself as the Western Power Pool in February 2022. The WPP board approved the tariff in August, sending it to FERC. (See *Western Power Pool Board Approves WRAP Tariff*.)

The commission responded in November with a deficiency letter that asked WPP to provide clarifications on the tariff filing, including about the program's proposed requirement that participants secure transmission rights well in advance and about its intent to hire an independent evaluator to assess its performance. (See *FERC IDs Deficiencies in Western RA Program*.)


The WRAP signed up 26 participants in 10 states and one Canadian province for its nonbinding phase. | *NWPP*

WPP *responded* to FERC's questions Dec. 12, leading to the commission's determination Friday.

FERC addressed a number of comments, protests and concerns, including questions about transmission commitments. The program's forward-showing component requires participants to show they have sufficient capacity and 75% of the transmission necessary to deliver it seven months ahead of each summer and winter. Penalties will apply to those who do not.

The Northwest & Intermountain Power Producers Coalition (NIPPC) argued that the "required use of firm transmission contradicts the commission's allowance for use of non-firm transmission in similar circumstances," FERC said.

NIPPC also had "concerns with the 75% forward-showing transmission requirement, including the lack of support for the specific figure of 75%, the potential for market power being exercised by incumbent firm transmission rights holders and transmission providers, and the practical reality that transmission providers regularly release sufficient short-term [available transfer capability] well after the WRAP's forward-showing deadlines to meet program needs."

"NIPPC states that this will lead to regular requests for exceptions," the commission said.

FERC disagreed with NIPPC's protest. WPP's forward-showing program "includes reasonable requirements to ensure deliverable resource adequacy, while also providing necessary flexibility to participants. Further, we find that the requirements of the proposed program can help to enhance price formation in the Western Interconnection by sending price signals to market participants regarding the availability of capacity and firm transmission service and the need for future market entry."

With respect to the independent evaluator, FERC staff had asked WPP in November whether the evaluator's report would be made public.

WPP responded that the evaluator's annual reports are "intended to be made public" and proposed a tariff revision to explicitly state that the "independent evaluator's annual reports shall be made available to the public, except to the extent that they contain information designated as confidential under this tariff, or information designated as confidential by the independent evaluator."

FERC accepted WPP's clarification and tariff revision.

"We recognize that for the commission, state regulators, participants and other stakeholders, the independent evaluator's reports will be a key source of information and analysis on the WRAP's operation," FERC said. "Further, the WRAP is a novel design for the Western Interconnection, and as the program matures, the insight into its functioning will provide useful information and transparency to all stakeholders."

In a news release Friday, WPP CEO Sarah Edmonds said, "We're so pleased that FERC shared the industry's appreciation for the value of a regionwide resource adequacy program and supported our vision for it. This is a critical step for the West to help ensure that we can achieve a clean energy future, without sacrificing reliability."

The WPP will next make governance changes required by the tariff by seating an independent board of directors that it *named* in October.

"Our governance model, including an independent board of directors, is a critical piece of the WRAP," Edmonds said. It "was demanded by our stakeholders and establishes the standard for regional organizations like this one." ■

## CAISO/West News

# FERC OKs WEIM Changes for Wash. Cap-and-trade Costs

*By Robert Mullin*

FERC on Friday approved Western Energy Imbalance Market (WEIM) tariff revisions to allow generators to include costs associated with the Washington cap-and-trade program in their default energy bids and commitment costs.

The commission approved the revisions over the objection of the Utah Division of Public Utilities (UDPU), which argued the rule changes run afoul of the U.S. Constitution because they impose an unlawful "border tax" on electricity imported into Washington (*ER23-474*).

WEIM operator CAISO filed the tariff changes late last year in anticipation of the Jan. 1 roll-out of Washington's cap-and-trade regulations, which require any in-state emitters of more than 25,000 metric tons of carbon a year — including electricity generators — to acquire allowances to cover their emissions. The rules also apply to any electricity imported to serve Washington demand.

CAISO's rule changes have to do with the reference levels the ISO uses to calculate a resource's default energy bids and commitment costs for the WEIM. In its filing with FERC, the ISO proposed to alter the reference levels to allow generators selling into Washington to reflect GHG compliance costs in their market bids to ensure that those resources don't appear be less expensive than their actual costs.

CAISO modeled the changes on tariff provisions already in place to accommodate California's cap-and-trade program, which is administered by the state's Air Resources Board (CARB). Under those provisions, the reference levels used in the default energy bid and commitment costs are based on a GHG allowance price derived from the average of two index prices published by separate vendors.

Washington's cap-and-trade program is not tied to CARB's, and the Washington-specific provisions approved by FERC on Friday differ in their details because the state's Department of Ecology will not be holding an allowance auction until later this month, meaning there is not yet a published allowance price available to set the reference level. CAISO instead proposed a three-phase rate that will change in response to certain "triggers," FERC noted.

In the first phase, before the first auction, CAISO will rely on a reference rate of $41/metric ton (MT), the halfway point between the Ecology Department's floor and ceiling prices of $19.70/MT and $72.29/MT, respectively. For the second phase, CAISO will use the clearing price from the most recent quarterly auction until index prices become available. In the third phase, the ISO will rely on the average of two index prices from separate vendors, similar to its treatment of the CARB program.

The ISO contended that an index price would eventually provide a more accurate reflection of the price for Washington allowances.

"CAISO indicates that while the auction price is a starting point, as Washington's cap-and-invest program evolves, CAISO expects market participants will engage in bilateral trading, which will cause deviations from the auction price. According to CAISO, an index price, updated daily on weekdays, provides a timelier estimate of the allowance price," FERC wrote.

Washington's new cap-and-trade rules apply to nearly all GHG emitters in the state, including TransAlta's coal-fired Centralia Power Plant. | *Steven Baltakatei CC-BY-SA 4.0, via Wikimedia Commons*

### Constitutional Questions

In approving the WEIM tariff provisions, FERC rebuffed the sole protest by the UDPU, a Utah agency charged with investigating consumer utility complaints and monitoring utility operations to ensure compliance with state Public Service Commission rules.

The UDPU contended that the tariff changes violate the Constitution's Supremacy Clause because they subject out-of-state generators to Washington's state-levied allowances, contravening FERC's "exclusive authority to regulate the sale of electric energy at wholesale in interstate commerce."

"UDPU states that the CAISO adders for compliance with state-specific cap-and-invest programs will affect the set of resources selected for generation in the WEIM, causing commission-jurisdictional markets to clear in significantly different ways than they would in the absence of those directly-imposed bid costs," FERC noted.

The agency had also argued that Washington's cap-and-trade program is unconstitutional under the dormant Commerce Clause because it imposes a "border tax" on energy imported into Washington. And it additionally contended that the program provides preferential treatment to in-state interests because Washington utilities are provided a free allocation of GHG allowances, buffering the state's ratepayers from the burden of some compliance costs.

The commission said it was "not persuaded" by the UDPU's arguments, noting that it could only consider whether the tariff provisions were just and reasonable under the Federal Power Act, and not the legality of the underlying law motivating the provisions.

FERC wrote that the revisions "simply allow generators to incorporate compliance costs associated with Washington's cap-and-invest program in their default energy bids and commitment costs, which account for the variable costs of generation and provide generators a reasonable opportunity to recover their costs." Those revisions are consistent with other commission-accepted tariff provisions that accommodate the compliance costs associated with state environmental requirements — including in the WEIM, the commission said.

The commission similarly found the UDPU's "border tax" argument to be aimed at the constitutionality of the cap-and-trade program, saying a FERC proceeding was not the proper venue for addressing such a question.

"In any case, if the commission were to reject CAISO's filing based on constitutional grounds, and if Washington's cap-and-invest program were not ultimately enjoined by a federal court, generators would be deprived of the opportunity to recover costs that they are legally obligated to incur," the commission said. "As long as the tariff revisions at issue apply to the mandatory compliance costs incurred by generators within the borders of Washington and which are subject to Washington's jurisdiction, we are required to allow the opportunity for their recovery." ■

## CAISO/West News

# West, Southeast Need Tx Planners, Report Says

### *Independent Transmission Monitors One Possibility*

*By Hudson Sangree*

The non-CAISO West and the Southeast U.S. need independent regional transmission planning entities even if the entities are not RTOs, a report released Thursday by Clean Energy Buyers Institute and Grid Strategies contends.

In contrast to much of the nation, the regions are not part of RTOs or ISOs that perform transmission planning and depend largely on individual utilities to propose projects, the research group and consulting firm noted.

"Customers in two-thirds of the country rely on independent, trusted, expert transmission planners to achieve greater reliability and cost-savings," Grid Strategies President Rob Gramlich said in a news release accompanying the report. "Western and Southeastern customers deserve the same benefits."

The *report* says RTOs would provide the greatest benefits but that other types of organizations could do important jobs.

In the West, "little regional planning takes place" outside CAISO, it notes. "The FERC 1000 Regional Planning Entities are Northern Grid, WestConnect and CAISO. Northern Grid and WestConnect tend to simply roll up the plans submitted by each utility."

One entity that could provide some RTO-like services is WECC, the reliability organization for the Western Interconnection, CEBI and Grid Strategies suggested.

"Currently, the Western Electric Coordinating Council does not manage transmission planning, but it is well positioned to play a greater role," their report says. "The entity covers the whole Western region, plus western Canadian provinces and a small part of Mexico, and has some independence from the utilities. WECC or another regional planning entity could begin performing technical studies of transmission needs and options that would be valuable for stakeholders."

In the Southeast, three entities — Southeast Regional Transmission Planning, South Carolina Regional Transmission Planning and Florida Reliability Coordinating Council — nominally are responsible for transmission planning, but "like the West, these entities simply aggregate the utilities' individual plans and periodically brief stakeholders without seeking input or sharing sufficient data, methods or assumptions to enable an assessment of the projects," it says.

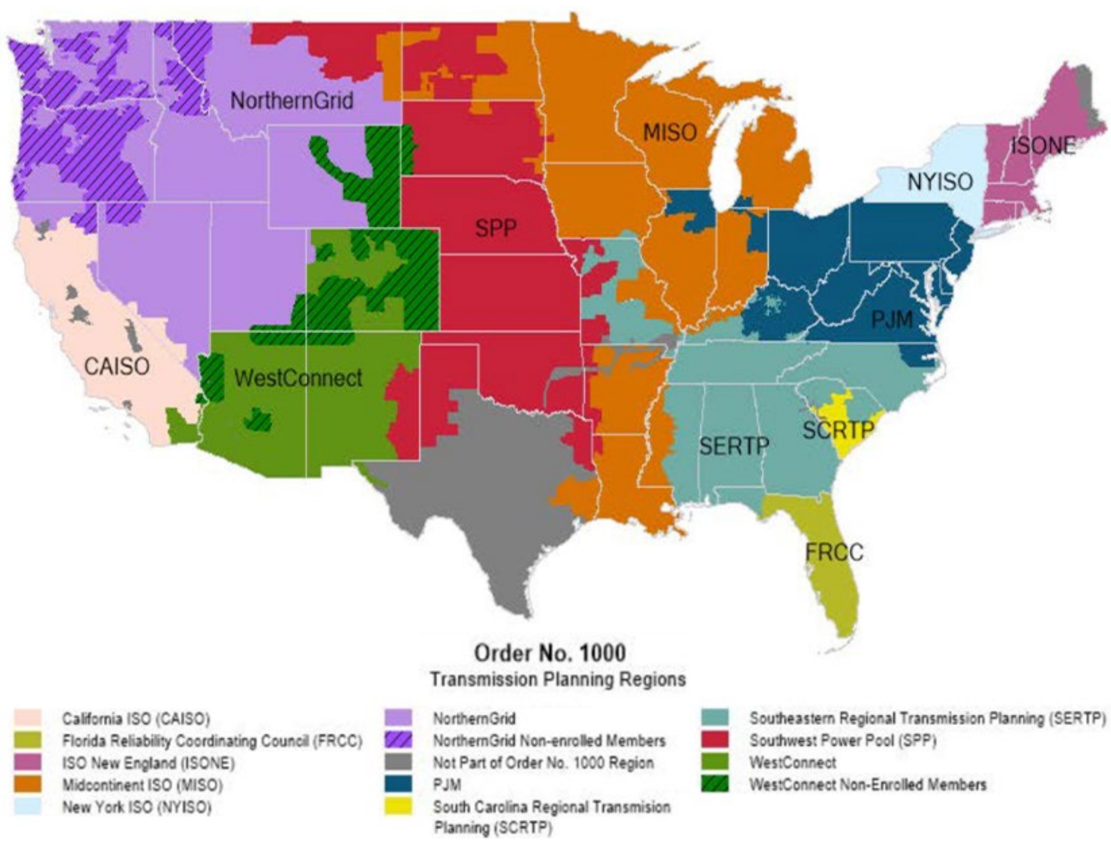
The Eastern Interconnect Planning Collaborative, which "covers the entire Eastern Interconnect and can evaluate interregional as well as regional opportunities," could take on additional responsibilities, CEBI and Grid Strategies said. "This process is broad and inclusive and strives to plan backbone transmission facilities that enable interconnection-wide energy outlet and bulk transfers of power."

FERC has encouraged the formation of RTOs such as PJM, MISO and SPP. "However, none of the relevant FERC orders (2000, 890 and 1000) require that planning functions be performed by an RTO," the report says.

Independent transmission monitors (ITMs) have been proposed as a means of increasing transparency and oversight in regional planning, it notes.

During an Oct. 6 FERC technical conference on transmission planning, state regulators and consumer advocates urged FERC to order the creation of ITMs and to take other measures to increase oversight of transmission owners' planning and spending. Witnesses representing transmission owners strongly opposed the ITM concept. (See *States Urge More Transparency on Tx Planning, Independent Monitors*.)

"The ITM has not been formally proposed by FERC at this point, and there are different versions of what it would do," the report notes. "At a minimum, an ITM could provide information to market participants about transmission needs and opportunities, while complying with [FERC] Critical Energy Infrastructure Information requirements." ■




The non-CAISO West and Southeast lack the centralized transmission planning of regions with RTOs and ISOs. | *CEBI*

## ERCOT News

# Market Monitor Pans ERCOT Market Redesign

### *Latest Legislative Hearing Shows Skepticism over PCM Proposal*

*By Tom Kleckner*

ERCOT's Independent Market Monitor continues to criticize Texas regulators' preferred market redesign, saying the proposal is a "less effective and efficient means" to manage the market's generation fleet.

During a hearing before the state Senate's Business and Commerce Committee Feb. 7, Potomac Economics' Carrie Bivens said the IMM does not support the performance credit mechanism (PCM) that the Public Utility Commission agreed to last month. (See *Texas PUC Submits Reliability Plan to Legislature*.)

The PCM rewards generators in ERCOT's energy-only market with credits based on their performance during a determined number of scarcity hours. Those credits must either be bought by load-serving entities or exchanged between them and generators in a voluntary forward market.

ERCOT IMM Carrie Bivens (right) testifies before the Texas Senate as PUC Chair Peter Lake (left) and E3's Zach Ming listen. | *Texas State Senate*

Bivens said the IMM believes that recent modifications to the ISO's operating reserve demand curve after the deadly 2021 winter storm provide "more than sufficient price signals" to retain market resources. She told lawmakers the PCM is a "novel concept" that will likely result in unintended consequences because of its design "challenges."

"Our evaluation of the concept is that it decreases the efficiency of the energy market," Bivens said. "In our opinion, if it's designed appropriately, the most likely result is that performance credits will clear at zero and not add any benefits, since we're already meeting the reliability standard. Otherwise, it may disrupt and distort the market leading to inefficient outcomes at increased costs."

Sen. Jose Menendez | *© RTO Insider LLC*

Sen. Jose Menendez (D) asked Bivens who would bear the costs of implementing the market mechanism. Energy and Environmental Economics (E3), a consulting firm hired last year by the PUC to review various proposed market revisions, put the implementation cost at $460 million.

"It shifts the risks from generators on to the load, and so it most benefits generators," said Bivens, who has said the $460 million would be a minimum estimate for incremental costs.

She said the IMM has not performed its own analysis of the PCM's costs, saying there are still several outstanding factors that "frustrate the ability" to derive an accurate cost estimate.

"Most particular is how the demand curve is going to be formulated. That is going to be a huge contributor to how much these items are going to cost," Bivens said. "The reason I say that's the minimum is because a model such as E3's is going to assume perfect decisions, perfect capacity, no overbuild, no underbuild, no market-power abuse. You know, perfect information by all the participants, and that doesn't exist in the real world."

E3 has said the credits could cost retailers $5.7 billion a year, but that could be "significantly" offset by an overall decrease in energy costs.

Bivens agreed with Menendez that it is inaccurate to say no new thermal generation has recently been built, as Sen. Robert Nichols (R) said during an opening history lesson on ERCOT's market development.

"We're continuing to lose dispatchable power," Nichols said. "No one is building anything new."

The IMM noted in *comments* to the PUC that since 2014 the market has added about 7 GW of thermal generation — all natural gas, just the fuel type lawmakers asked for with legislation after the winter storm.

Asked by Menendez about the possibility of self-dealing among the so-called gentailers (companies with both generation and retail affiliates), Bivens said the IMM will work with the PUC to address market-power concerns, should the credit mechanism move forward.

Price manipulation is a concern "in every market, such as this one, in which there's a concentration of supply," she said.

Bivens was part of a three-person panel that also included PUC Chair Peter Lake and E3's Zach Ming. Lake and Ming spent much of their time defending the PCM as Bivens sat silently for more than four hours.

"I've been very impressed with just your steadfastness," Sen. Phil King (R) told her.

Senators questioned Lake and Ming on how the PUC's proposal would incent the dispatchable generation they and other lawmakers requested during the 2021 legislative session. As the committee's own *press release* put it, the PCM "was met with skepticism by members."

"This is the first of its kind. We've seen the first of its kind before. Sometimes it works; sometimes it doesn't," Sen. Lois Kolkhorst (R) said. "We cannot miss on this. It's critical."

"If this PCM plan is adopted, will these new plants ever come online?" Sen. Brian Birdwell

# ERCOT News

(R) asked Lake.

"We know market forces work," Lake responded.

Asked whether the PUC could promise more reliability, Lake said, "Our goal was to provide you all the broad definition of the best reliability service that we could identify as a result of our analysis, and we recognize that there are a lot of technical questions yet to be answered."

Lake told the committee he would put further planning on hold while they think things over.

As the hearing ended, an anonymous market participant who goes by the Twitter handle "King of Power," *tweeted* that the "least bad option politically" would be for Texas to subsidize loans to new gas generators. That would be just fine with Lt. Gov. Dan Patrick, who presides over the Senate. On Monday, Patrick listed "adding new natural gas plants" as one of his *top priorities* for the session; he has threatened special sessions if he doesn't get his way.

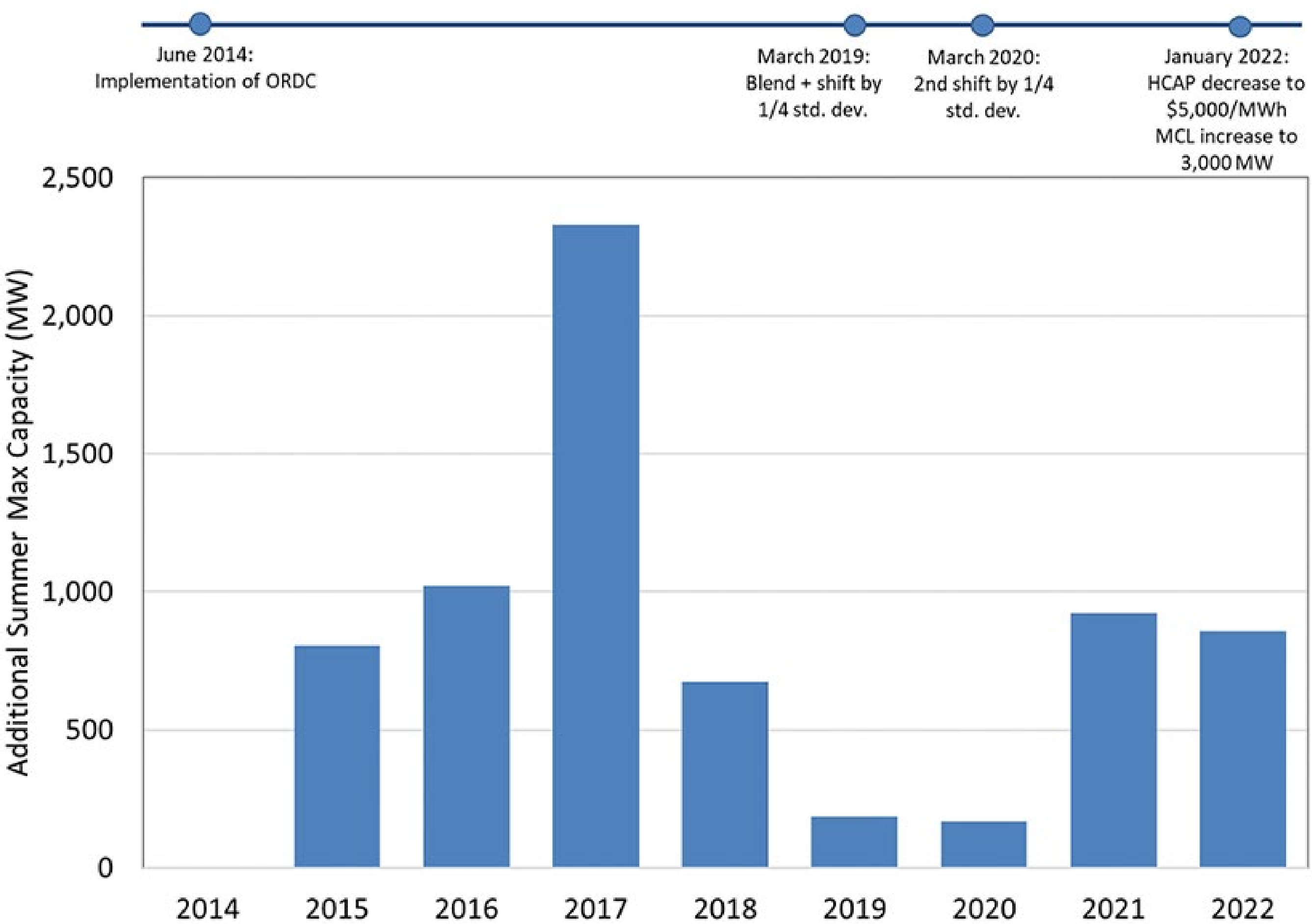
The tweet continued: "Lt. Gov and company get new gas plants, PCM is killed, [energy-only] market is intact, and senators can say they leveled playing field vs [environmental, social, and governance investing]."

Sen. King conducted the hearing after the committee's chair, Sen. Charles Schwertner (R), spent the previous night in the Travis County Jail after being *arrested* for driving while intoxicated.

"The chair, as you know, is not going to be able to be with us today," King said as he opened the hearing.

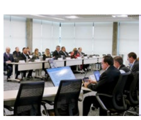
In a *statement*, Patrick said he will wait on the final outcome of Schwertner's legal case before making a further statement. However, some have speculated this could cost the senator his chairmanship. Schwertner has been a vocal critic of the PCM, calling it a "costly and complex proposal that is unlikely to deliver the dispatchable generation resources that Texas needs."

It's not the first time Schwertner has found himself in hot water. He was *investigated in 2018* for sending sexually-explicit text messages to a University of Texas graduate student. The inquiry ended when it determined that it was "plausible" that a third party had sent the messages. ■




ERCOT has added about 7GW of dispatchable generation, all gas, since 2014. | *Potomac Economics*

## South news from our other channels



*Texas RE Board/MRC Briefs: Feb. 8, 2023*

ERO Insider

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ISO-NE News

# What's Next for Massachusetts' FCEM Proposal?

By Sam Mintz

Massachusetts kicked off the year by giving new life to a longtime goal of many climate and clean energy advocates in New England: developing a Forward Clean Energy Market.

The FCEM idea has been floating around New England since at least 2016, when it was put forward by renewable energy companies.

It has evolved into a *proposal* that the Massachusetts Department of Energy Resources (DOER) put out in the first week of January, relying on help from consultants at the Brattle Group and Sustainable Energy Advantage. (See *Massachusetts Floats FCEM Proposal*.)

"Our current market structures and the current procurement process, although they provide a lot of incentives, it's difficult to scale those both in size and speed," Joanna Troy, Massachusetts' director of energy policy and planning, said in a recent webinar.

That's why the state has put forward the regional plan, aiming to accelerate the development of clean energy sources to help Massachusetts and the region's other states meet their ambitious goals.

But with the document now out and making the rounds, the question floating around New England's energy stakeholders is: "Now what?"

As the state tries to advance its plan to start a regional clean energy market, it will have to face down a heavily bureaucratic stakeholder process, a cautious grid operator, and the general inertia of a region that remains way behind on its decarbonization goals.

The key to Massachusetts' proposal, energy and climate experts say, is that it remains flexible and gives states some leeway to transition their own existing, patchwork clean energy incentives into a regional market over time.

"It's tailored to the fact that the region has a bunch of renewable energy decarbonization goals that have different flavors to them," said Pete Fuller, a consultant at Autumn Lane Energy Consulting.

"What the DOER and their consultants have done here is to try to meet the region where it is and create a platform … that will enable the region to meld existing policies and objectives into this new platform. I'm very encouraged by that," Fuller said.

The proposal includes four types of clean energy certificates with varying degrees of resource specificity; plus it would allow states to offer their own individual RECs or other existing incentives on the regional platform.

That would let the New England states access the market without necessarily making any changes to their existing statutes — at least at first.

Susannah Hatch, director of clean energy policy at the Environmental League of Massachusetts, echoed that understanding of the FCEM plan's design.

"It's an additive feature to existing markets currently being administered by ISO-NE, which would still allow states to explore procurements outside of it," she said.

But she said she'll be watching closely to see how the market would address the fact that sometimes cost isn't the overriding factor in procuring energy.

A solar panel installer in Boston, Mass. | *Shutterstock*

"Renewable energy sources are not apples to apples," she said. "We definitely want to make sure that the market incentivizes a balanced renewables portfolio for New England."

## Big Governance Questions to Answer

What's prevented FCEM from moving from concept to reality is primarily a complex set of questions about how the market would be governed.

To what extent would ISO-NE be involved? Would the market be FERC-jurisdictional? How would the states share control of its design and operation?

The Massachusetts proposal recognizes the difficulty of answering those questions and puts forward a preliminary plan that includes creation of an independent nonprofit governed by representatives of the six states, which would work alongside ISO-NE and have the ability to propose rule changes to FERC.

But it also mentions possible alternatives and says the states will keep studying.

"The fact that Chapter 1 of the report is governance highlights the importance of that topic and hopefully jumpstarts those conversations so that we can begin to resolve this stuff and put some real certainty to a structure, rather than the sort of speculative conversations we've been having," Fuller said.

As far as ISO-NE is concerned, the ball is fully in the states' court.

ISO-NE spokesperson Matt Kakley said the grid operator is "reviewing the proposal and awaiting further guidance from the New England states on whether this is a path they'd like to pursue."

Fuller said the RTO is a "cautious beast."

"And they are very anxious that the states lay out a clear plan and really provide a definitive direction," he said. "Once the states do that, then I think the ISO will engage, and I think we can all get into problem solving."

Troy said that the state's priority is getting feedback from the public.

After that, she said, Massachusetts will "continue discussion within the NESCOE setting with other states before determining what or if an additional NEPOOL or process would be necessary." ■

## ISO-NE News

# NEPOOL MC Gives OK to Inventoried Energy Program Tweaks

*By Sam Mintz*

The NEPOOL Markets Committee last week signed off on *changes* to the Inventoried Energy Program that are intended to get the winter reliability program back in line with global energy markets.

If approved by the full Participants Committee at its next meeting, the changes will incorporate an indexed forward rate to automatically adjust to changes in gas market prices ahead of next winter.

The tariff changes also alter the program's gas contracting eligibility provisions, an effort to help increase the amount of inventoried energy brought to the region for the next few winters.

In approving the changes, the committee also rejected an *amendment* from Generation Bridge, which owns four natural gas units in Connecticut. The company wanted ISO-NE to change the maximum amount of stored fuel to be counted in the program from 72 hours to 120 hours.

Changing to 120 hours, Generation Bridge argued, would increase incentives to fill large tanks or arrange for more LNG in preparation for extended cold snaps. And it would improve the likelihood that units with oil capability but no capacity supply obligation would be available in the coming winters, the company said.

The committee, however, ultimately rejected that proposal.

### Drilling down on DAS

The MC also continued to discuss ISO-NE's proposed framework for a day-ahead ancillary services (DAS) market, *diving into* eligibility for the "flexible response services" (FRS) and energy imbalance reserves (EIRs) that will make up the core of the market.

Energy sources eligible for FRS will have to be dispatchable and located physically within ISO-NE (so no imports or virtual resources would be eligible). They would have to be unconstrained by transmission, not part of first-contingency supply loss and sustainable for a minimum of an hour.

EIR resources would also have to be physical supply resources located within the bounds of ISO-NE and either committed in the energy market already or a fast-start resource.

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

The committee also discussed settlement rules for the DAS market, which would be "largely unchanged from those proposed during Energy Security Improvements discussions in 2019-2020." ■

# MISO News

## Initial MTEP 23 Ignites Familiar Arguments over MISO South's Reliability Spend

*By Amanda Durish Cook*

MISO's preliminary 2023 Transmission Expansion Plan (MTEP 23) will double recent spending, driven by a record number of proposed baseline reliability projects in MISO South.

MTEP23 has a proposed investment of $7.8 billion, nearly twice that of standalone packages over the last five years.

Almost half of the 2023 transmission planning cycle's tab goes to essential reliability projects in the South, as deemed by transmission owners. That prompted many stakeholder questions and assurances from MISO that it will examine proposals for larger, combined project opportunities.

The project cost estimate includes $4.1 billion of baseline reliability projects (BRPs), $757 million in generator-interconnection projects, $2 million in market participant-funded projects, and $2.9 billion in "other" category projects. The RTO defines the latter as transmission owners' projects needed for load growth and to address existing facilities' age and condition.

MISO South accounts for $3.6 billion of the baseline reliability projects, equal to previous MTEP packages' total cost. Entergy Louisiana *submitted* more than half of the South's BRPs, with 13 projects costing $2.4 billion.

BRPs are proposed by transmission owners, not cost shared, and billed only to the local transmission zone in which they're located. TOs typically deem the projects necessary to meet reliability criteria. MTEP 22's BRPs accounted for $545 million of the package's total $4.3 billion. (See *Stakeholders Endorse MISO's Final MTEP 22*.)

This year's drastic increase in MISO South reliability transmission investment raised eyebrows among stakeholders, who said staff should determine whether some of the larger projects should be classified as regional.

During a Feb. 3 South Subregional Planning meeting, MISO's Trevor Armstrong said planners are aware of the record number of BRPs put forth by MISO South TOs.

During a *series* of subregional planning meetings last week and the week before, staff emphasized that the projects are merely proposals at this point. MISO has yet to perform independent assessments to determine whether the projects can effectively solve system issues.

"We'll be talking to our transmission owners about alternatives to some of these projects," Armstrong said. "I'd like to note that these projects have only been proposed; they still have to go through all the usual MTEP analyses."

Southern Renewable Energy Association Executive Director Simon Mahan asked whether any of the BRPs will be evaluated to potentially become market efficiency projects (MEPs) or long-range transmission plan projects, which are allocated on a subregional basis. Staff promised test results by the third round of subregional planning meetings in September.

Jeanna Furnish, the RTO's director of expansion planning, said staff will only study BRPs for potential MEP inclusion if they meet tariff requirements of costing at least $5 million, are 230 kV and above, and have at least a 1.25:1 benefit-to-cost ratio.

"I know that there are a lot of questions around this process," Furnish said, adding that MISO will hold discussions on the projects' eligibility at future subregional planning meetings. She also said staff can schedule technical study task force meetings if it appears that South BRPs qualify as regional projects.

"We've never had a market efficiency project built in MISO South," Mahan said.

Armstrong said MISO could even extend its December deadline for approving certain MTEP 23 projects. He said some of the BRPs proposed in the South are complex and it will take several engineering hours to ascertain whether a more comprehensive project is needed.

"When you say that you might delay certain projects out of this MTEP cycle … when might be hearing about this?" Mahan asked.

Furnish said MISO will have a better handle later this spring.

Stakeholders asked whether MISO's tariff stipulates that it must first conduct a market congestion planning study to recommend MEPs. Those normally identify MEPs. Furnish said she didn't think the RTO's rules were that "prescriptive."

The skepticism over the MISO South BRPs continues a debate over whether the grid operator is adequately exploring project alternatives. Last year, a spate of expedited project recommendations in the region led some stakeholders to question whether the RTO is engaging in thorough and cost-effective transmission planning. (See *Stakeholders Doubt MISO Study of Alternative Tx Projects*.)

During a West subregional planning meeting Feb. 7, planners reassured stakeholders that MTEP 23 project classifications won't be confirmed until late summer.

Expansion Planning Manager Zheng Zhou said if MISO finds that a project meets the criteria for both a BRP and an MEP, the MEP classification will take precedence and the project will be allocated as such.

"Alternatives are a hot topic," Zhou said.

He urged stakeholders to remember that MTEP23 amounts are preliminary and subject to change. He also said that it's sometimes impossible to find a "cheaper, more economic" solution for certain localized issues.

During Wednesday's East subregional meeting, Thompson Adu, senior manager of expansion planning, said MISO may look into more expensive projects than originally proposed that resolve a host of problem areas. On the other hand, he said, staff may discover that some local upgrades have no viable alternative.

Stakeholders have until May to propose alternatives to the TOs' project proposals. ■


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## MISO News

# MISO Members Re-establish Stakeholder Governance Group

*By Amanda Durish Cook*


MISO's Carmel, Ind., headquarters | *© RTO Insider LLC*

Stakeholder committee chairs last week restored a MISO stakeholder governance group to manage matters related to the RTO's stakeholder governance guide.

MISO's Steering Committee, comprising stakeholder group heads, on Thursday approved the Stakeholder Governance Working Group's (SGWG) *charter* that describes the group as an "open forum" for stakeholders to "oversee and manage" the RTO's *Stakeholder Governance Guide.*

The guide lays out how the various committees, work groups and task forces are structured and how meetings should be conducted. The SGWG will conduct periodic reviews of the governance guide, address stakeholders' suggestions to improve the stakeholder process and discuss concerns over meeting facilitation.

The working group will meet twice per year or as needed. Meetings are open to all interested stakeholders.

The SGWG was disbanded about seven years ago, leaving only members of MISO's advisory and steering committees to propose and develop revisions to the governance guide. (See *MISO Members Want to Revive Stakeholder Governance Group*.)

MISO's stakeholder relations group will request leadership nominations via email and schedule the first meeting later this month.

Reliability Subcommittee Chair Ray McCausland, with Ameren, proposed reviving the small stakeholder group last year and volunteered to chair it.

"I'm really excited to see this invigorated again," said Steering Committee Vice Chair Sarah Freeman, who sits on the Indiana Utility Regulatory Commission. "It's great to see so many stakeholders interested in how we conduct our business at MISO."

Xcel Energy's Carolyn Wetterlin, vice chair of the Cost Allocation Working Group, said it was reassuring to have the stakeholder community's "governance geeks" back on the job.

Freeman said she would like to see the SGWG tackle how the Advisory Committee can have more input into tariff change filings before MISO sends them to FERC.

"I think the governance process has suffered to some extent because of the stakeholders that can talk about it," McCausland said, a reference to the years that only Advisory Committee and Steering Committee members could direct governance guide changes. ■

## NYISO News

# FERC Grants Interconnection Waivers to 13 NY Renewable Projects

FERC last week granted waivers to 13 renewable generation projects, allowing them more time to have their interconnection studies approved by NYISO's Operating Committee before entering the 2023 Class Year (CY23) study.

Current NYISO tariff procedures require projects participating in a class year study to have their system reliability impact study (SRIS) approved by the OC before entering the study, which began Monday.

Invenergy, York Run, Boralex, Barrett Hempstead, ConnectGen, Gravel Road, Microgrid Networks, Thousand Island, Innisfree Storage, North Country Wind, Crane Brook Solar, Union Energy Center and North Seneca Solar each asked the commission for its SRIS to have until the completion date of the Annual Transmission Baseline Assessment base cases for CY23 to be voted on by the OC (*ER23-803*, *ER23-787*, *ER23-798*, *ER23-783*, *ER23-786*, *ER23-830*, *ER23-785*, *ER23-780*, *ER23-867*, *ER23-860*, *ER23-893*, *ER23-859* and *ER23-894*).

The projects were unable to meet the Monday deadline. Their requests were supported by NYISO, other state agencies and the Alliance for Clean Energy New York (ACE NY).

The developers argued that they performed procedural due diligence, requested NYISO to expedite their SRISes and kept the ISO informed about their progress.

NYISO told FERC that study delays occurred from a variety of factors, including multiple revisions or material alterations. ACE NY and agencies including NYSERDA said further development delays could limit both health benefits to citizens and emissions reductions.

| © RTO Insider LLC

Each request also cited how FERC had granted similar waivers to the Clean Path New York transmission project.

FERC said it granted the waivers because the facility projects "acted in good faith," made requests "limited in scope" that related to "a single timing requirement," could experience significant delays in their development and because granting them would not have "undesirable effects" on other CY23 participants. ■

*— John Norris*

# NYISO's Bouchez Begins New Job as Consumer Liaison

NYISO *announced* on Thursday that Nicole Bouchez had begun working in her new position as senior principal economist and consumer interest liaison for market structures.

The ISO first announced the promotion last month to the Business Issues Committee. (See "Bouchez Named Consumer Liaison," *NYISO Business Issues Committee Briefs: Jan. 18, 2023*.)

Bouchez has been with NYISO since 2003 and served as principal economist since 2011. In her new role, she will inform the consumer sector about changes in the wholesale energy markets and their implications, as well as serve as a coordinator for the ISO's consumer-related initiatives, such as analyzing market developments or design changes.

Dr. Nicole Bouchez | *NYISO*

"I am looking forward to working with the end-use consumers to provide valuable insights and information about market design changes," Bouchez said in a statement. "This is an exciting time of change in the electric industry, and providing timely information is an important part of a successful transition."

In an email to *RTO Insider*, Bouchez said she is "most excited about providing useful information about changes in the wholesale markets."

NYISO CEO Rich Dewey commended Bouchez in a statement, saying "the expertise and experience that Nicole provides to our market teams and stakeholders is second to none," and that the ISO "will continue to rely upon Nicole's knowledge and guidance on changes in the markets." ■

*— John Norris*

NYISO News

# NYISO Operating Committee Briefs

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### January Operations Report

NYISO on Monday updated the Operating Committee on January operations performance and how the early-February cold snap event impacted the grid.

ISO Vice President of Operations Aaron Markham said peak load for the month occurred on Jan. 31, at 20,641 MW, lower than the 22,004-MW peak load for the winter and far below the record of 25,738 MW, set in January 2014.

The cold weather event, which occurred Feb. 3 to 4, did not drop temperatures as much as during the December winter storm, but it caused roughly 2,000 MW of day-ahead-committed generation to become unavailable in real time.

Markham told stakeholders that a full operations report on the February cold weather event would be shared in March.

### Emergency Operations

Stakeholders approved *manual* updates for manual emergency operations.

The manual provides rules and regulations that NYISO and market participants must follow in the event of a power system disturbance to both prevent further disruption and restore normal operations as soon as possible. The revisions include removing references of shift supervisor throughout, updating indexed tables and clarifying contingencies for non-NYISO controlled facilities.

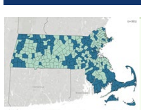
### FERC Interconnection Waivers

NYISO attorney Sara Keegan told stakeholders that 22 generation projects requested interconnection waivers from FERC to participate in the forthcoming 2023 Class Year study, but only 13 waivers were granted.

FERC granted eight waivers on Thursday and five more on Friday. (See related story, *FERC Grants Interconnection Waivers to 13 NY Renewable Projects*.) ■

*— John Norris*

## Northeast news from our other channels



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# Policymakers Working to Meet Spiking Demand of Data Centers in Virginia

## *'Data Center Alley' in Northern Virginia Sees Growth Accelerating*

*By James Downing*

Data centers have been a major business in Northern Virginia for decades, but a recent acceleration in their growth has policymakers working to make sure their high demand for electricity continues to be met reliably.

"Data Center Alley," near Dulles Airport outside of D.C., is home to the largest concentration of data centers in the world, easily outpacing Silicon Valley, according to the Loudon County Department of Economic Development.

Northern Virginia has ties to the earliest days of the internet, from when the Defense Department's Advanced Research Projects Agency (ARPA) set up ARPANET in the 1960s, Steven Gonzalez Monserrate said in an interview with *RTO Insider*. Gonzalez Monserrate has worked in the industry and is pursuing a doctorate in the Massachusetts Institute of Technology's History, Anthropology, and Science, Technology and Society (HASTS) program on data centers' impact on the environment.

"There's another reason for it, which is national security," Gonzalez Monserrate said. "So, a lot of the data centers in Data Center Alley are government-related as well."

The cheap power from Dominion Energy has also led many data centers to plop down in its footprint. Data centers generally tend to cluster around each other because it minimizes the latency in internet connections, Gonzalez Monserrate said.

"People who play video games, for instance, or people who are doing trading on Wall Street, they need very low latency in the milliseconds to have a satisfactory experience," he added. "And so, the closer that your data center is to you the one that you're accessing and routing information, the lower the latency."

The importance of lower latency is driving additional construction of new data centers, as are new trends on the internet such as the "metaverse," Gonzalez Monserrate said.

The Virginia Department of Environmental Quality is taking comments on a proposal that would allow the 300 facilities in Northern Virginia to use their on-site backup generation more often from March through July in case the transmission grid is too overloaded to send them power.

Dominion is accelerating several transmission projects to alleviate constraints around Data Center Alley, which makes up 20% of the utility's overall demand and is the only major source of load growth there.

"This includes several reconductoring projects, substation expansions and two new 500/230-kV lines," spokesman Aaron Ruby said in a statement. "The first of the projects will be completed in late June and will help alleviate the constraints."

DEQ's proposal, which cannot go into effect until after it has taken written comments from interested parties and held a public hearing late this month, was issued out of an abundance of caution, and the issues will not impact service to residential or small business customers in the area, he added.

Individual data centers can have demand of up to 100 MW. Gonzalez Monserrate said that most of that power is used to run the servers of the cloud or to provide cooling for them. Cooling is often around 40% of the demand for more efficient facilities, though it can be higher than that, he said.

PJM has approved $627.62 million worth of transmission upgrades around Data Center Alley to avoid reliability violations observed in 2024 and 2025, which Dominion will build by 2025. Both houses of Virginia's General Assembly have unanimously voted out bills, *Senate Bill 1541* and *House Bill 2482*, that call on the State Corporation Commission to approve those upgrades within 270 days.

But load growth from new data centers has outpaced even those new lines, with PJM explaining it was opening a third window to the 2022 Regional Transmission Expansion Plan to deal with expanded data center demand expected through 2028.

PJM's 2023 *Load Forecast Report* showed Dominion's peak load growing at a rate of 5% per year over the next decade. The rest of the RTO is expected to grow by just 0.8% per year, with some regions seeing demand drop over the decade. In a presentation to the Transmission Expansion Advisory Committee in January, PJM said that its summer peak prediction for 2022 was off by 732 MW as Dominion had peak demand of 21,156 MW. That is expected to grow to 35,789 MW by 2033.

"This growth primarily driven by data center loads, which have been increasing at an unprecedented rate and will require significant new capital investment," Dominion CEO Robert Blue said on the firm's earnings call Wednesday. (See related story, *Dominion Energy Sees Loss in Q4; Earnings Fall for 2022*.)

Adding more transmission projects to the 2022 plan will ensure that the infrastructure is available before the demand shows up, PJM Director of System Planning Dave Souder told *RTO Insider* at the TEAC meeting Feb. 7. The rate of load growth driven by the industry is fairly new, and it is starting to impact other regions.

"Until recently, it has been atypical; however, there has been a significant data center load growth in the Dulles Airport area," Souder said.

The biggest internet companies in the world all have data centers in Northern Virginia, including Amazon, which is a major player industry through its Amazon Web Services subsidiary. The tech giant also picked nearby Arlington as its second headquarters in 2018, and in January it announced it would build another $35 billion worth of data centers in the state by 2040, which was welcomed by Gov. Glenn Youngkin (R).

"Virginia will continue to encourage the development of this new generation of data center campuses across multiple regions of the commonwealth," Youngkin said. "These areas offer robust utility infrastructure, lower costs, great livability and highly educated workforces, and will benefit from the associated economic development and increased tax base, assisting the schools and providing services to the community."

While the major players in the industry have committed to efficiency and renewable energy to meet their data centers' demands, Gonzalez Monserrate cautioned that some in the industry were not focused on such efforts at all.

"It's important to note that most data centers out there are not Google, or Amazon, or these giant facilities with a lot of capital; many of them are actually really poorly resourced or poorly run, or in aging facilities that don't have the resources to be energy efficient," he added. ■

*Devin Leith-Yessian contributed to this article from Valley Forge, Pa.*

# PJM Weighs Options on Winter Storm Elliott Follow-up

By Devin Leith-Yessian

PJM last week updated stakeholders on its progress in collecting up to $2 billion in non-performance penalties from capacity sellers who did not meet their obligations during Winter Storm Elliott.

In a filing submitted to FERC Feb. 2, PJM sought approval for a tariff amendment that would allow those charged with capacity performance (CP) penalties to elect to extend their billing period up to nine months when the charges are levied near the end of a delivery year (*ER23-1038*).

Under current practice, PJM typically takes three months to send out penalty notices after a performance assessment event (PAI) in which generators do not meet their capacity obligations. The penalties must then be paid by the end of the delivery year.

The Winter Storm Elliott PAI event, which occurred at the end of 2022, would leave generators about three months to make the payments, exacerbating concerns that the scale of the penalties could lead to defaults. (See *PJM Gas Generator Failures Eyed in Elliott Storm Review.*)

PJM's proposal would allow for the RTO to extend the billing period when the timing of the determination of the charges would leave fewer than six months to make payments, with the tradeoff of any payments made in the next delivery year being subject to interest at the FERC prevailing rate.

Since both options carry downsides, neither is being considered the default and PJM is asking those assessed penalties to notify staff of which billing timeline they are opting for by March 17, PJM CFO Lisa Drauschak said during a Feb. 8 *presentation* to the Market Implementation Committee. The RTO's FERC filing requests an order by April 4 to potentially allow for the new system to be put in place before stakeholders elect their timelines.

Drauschak said PJM hopes that extending the time for making payments will maximize the RTO's ability to collect non-performance charges while reducing the reliability risk from a significant number of resources defaulting and leaving the capacity market.

PJM released preliminary unit-specific data on CP charges and bonuses to relevant generators on Friday; however, Drauschak said the RTO does not usually publicly release preliminary aggregate figures.

Constellation's Jason Barker said he was disappointed that PJM has yet to release a more refined estimate of the total expected penalties, adding that he's unconvinced by PJM's argument that it hasn't been past practice given the magnitude of the emergency.

### PJM Changes Data Collection System

PJM is allowing generation owners to revise their ticket submissions in its eDART outage reporting tool, which the RTO's Dan Bennet said is used to derive CP performance data and the scale of any non-performance charges applicable for a given resource. Bennett *presented* to the Operating Committee on Feb. 9.

"We rarely make retroactive ticket changes, but given the nature of this event, … we wanted to make sure the data was accurate," he said.

After reviewing data submitted to eDART and NERC's Generating Availability Data System (GADS), the RTO and its Independent Market Monitor have found a wider difference than expected. While some discrepancy is to be expected given the real-time nature of eDART and the more precise data entered into GADS after an event, the usage of eDART data in determining performance charges makes accuracy crucial.

Calpine's David "Scarp" Scarpignato said that in the heat of events, generation operators often enter data at control centers rather than at the individual units and tend to be more conservative in representing their outages to ensure compliance.

Several stakeholders reported having trouble with updating their eDART data; PJM recommended that anyone running into issues reach out to its staff and the Monitor.

PJM has also opened a new *SharePoint* site to submit unit-specific inquiries and documentation regarding performance during the 277 PAIs over Dec. 23-24. PJM's Melissa Pilong recommended that submissions be made prior to March 6 to give PJM time to respond prior to the start of the billing period. ■

PJM CFO Lisa Drauschak | © *RTO Insider LLC*

# PJM OC Briefs

## No Consensus on IROL-CIP Cost Recovery

VALLEY FORGE, Pa. — PJM and its Independent Market Monitor gave first reads of their *proposals* exploring whether generators should be permitted to recover upgrade costs for facilities determined critical for interconnection reliability operating limits (IROLs) under NERC Critical Infrastructure Protection (CIP) standards.

PJM's proposal would create a cost recovery mechanism similar to black start service, where expenses can be submitted to both the RTO and Monitor for review and monthly payments would be made from revenue socialized across the RTO. PJM argued that the investments needed to comply with the standards are above what is typically required of generators and there is not a sufficient look-ahead in the analysis its staff does to identify critical facilities for a generator to include its expenses in future Base Residual Auction (BRA) offers. (See "Revisions to IROL CIP Issue Charge Rejected," *PJM Operating Committee Briefs: Dec. 8, 2022.*)

IMM Joseph Bowring said the concept of "cost recovery" is part of the old-fashioned cost-of-service regulatory model that is not relevant to markets. Bowring said it's already possible for generators to represent their IROL-CIP costs in market offers and it would be inappropriate to create out-of-market cost recovery for the expenses. His proposal would memorialize that there is no cost recovery structure in PJM's governing documents.

"PJM runs markets," he said. "PJM is not a regulator."

Rather than this being an issue for PJM to resolve, Bowring said generators should bear the costs. He compared the situation to investments facilities must make to comply with environmental regulations. No separate cost recovery mechanism was created for those costs, even though they were much larger than the IROL-CIP costs. Bowring also noted that there is no profitability test and that PJM plan proponents have no idea whether the identified generators are already more than covering all costs.

Greg Poulos, of the Consumer Advocates of the PJM States (CAPS), said state advocates are interested in seeing the most reasonable and best costs realized through markets. Creating cost-of-service structures creates a pathway for market participants to argue that each of their unique characteristics is a service that should be compensated.

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

Jim Davis of Dominion Energy said the comparison to black start is flawed because it is a voluntary service, while IROL-CIP critical status is determined by PJM. He said since that status is reevaluated annually, a facility may undergo significant upgrades only to have its critical marker removed after 12 months.

"The risk those resources have is [that] the rug could be pulled out from under them at the very last minute and have their status reverted back to low," he said.

## Security Update

PJM's Steve McElwee urged stakeholders to be on the lookout for hackers impersonating known figures and report any suspicious activity to the RTO. He said members recently reported a "phishing" attempt impersonating PJM staff and contacting members saying their accounts are being suspended.

"It really is that partnership for us to be working together," he said.

## Dynamic Line Rating Task Force Update

Stakeholders endorsed the conclusion of the Dynamic Line Rating (DLR) Task Force following the wrap-up of the group's work providing education as stakeholders and PJM drafted and implemented a new framework to incorporate the technology into its operations.

PJM's Natalie Tacka Furtaw *told* the OC that if future issues related to DLR arise, they can be addressed with a new problem statement and issue charge.

Stakeholders approved a problem statement and issue charge alongside a proposed solution under PJM's "quick fix" process at the April 2022 OC, and PPL went live with the technology in October. The task force continued to monitor the implementation of DLR and its impact to auction revenue rights and financial transmission rights trading; however, there have not been any new requests for information since its December meeting. (See "Dynamic Rating Issue Endorsed," *PJM Operating Committee Briefs: April 14, 2022*)

## Fuel Supply Overview

Fuel inventories are moving in the right direction, despite natural gas well freeze-offs and the derailment of a train in Ohio disrupting a major cog in the rail system for the eastern PJM region, Brian Fitzpatrick, PJM's principal fuel supply strategist, *told* the OC. With stockpiles improving and major transportation risks averted, namely the potential for a railroad strike, PJM is shifting to collecting inventory data biweekly rather than weekly.

"Generally speaking, we're starting to see an increase back in onsite inventories," he said.

A cold snap over Feb. 2-4 resulted in freeze-offs amounting to around 2 bcf/d in Appalachian supply, but mild weather has helped build a nearly 7% inventory surplus relative to the five-year average. Fitzpatrick said the impact to supply was minor compared to Winter Storm Elliott, which caused the loss of 10-11 bcf/d. Aside from the Dec. 23-24 storm, he said it has been an otherwise smooth winter for natural gas thus far.

The derailment of a Norfolk Southern train in East Palestine, Ohio, has not caused major issues transporting coal, and Appalachian production remains around 5% above last year's outputs

The mild winter has also helped East Coast inventories of diesel and residual fuel oil recover from being notably below the five-year average throughout 2022. ■

*— Devin Leith-Yessian*

# PJM MIC Briefs

## Vote on Multi-schedule Modeling of Combined Cycle Units Deferred

VALLEY FORGE, Pa. — The PJM Market Implementation Committee deferred a vote on adopting a *problem statement* and *issue charge* to discuss combined cycle modeling in the market clearing engine (MCE).

Following a lengthy back-and-forth on how broad the scope of the issue charge should be, PJM revised its proposed framework for the process.

The use of multi-schedule modeling for combined cycle is being considered as MCE software provider General Electric collects design preferences from PJM while building its Next Generation Markets Systems (nGEM).

Much of the discussion has focused on what types of schedules and selection methodologies should be considered in scope. PJM had initially presented a narrower issue charge that would have limited the scope to the "schedule selection process for commitment and dispatch for day-ahead and real-time energy market for all resource types outside of the MCE." (See "Feedback on Issue Charge, Problem Statement for Combined Cycle Modeling," *PJM MIC Briefs: Dec. 7, 2022*.)

After several stakeholders expressed concern that the issue charge was too narrowly focused on a specific solution rather than an issue, and Deputy Monitor Catherine Tyler presented an *issue charge* with a broader approach, PJM agreed to include a handful of items to be in scope.

Tyler said that of the six options that PJM had identified in its white paper as solutions to the issues, PJM had attempted to define four options as out of scope and therefore not part of the discussion.

PJM opposed the Monitor's proposal to include additional education in the issue charge, and stakeholders ultimately voted, with 60.8% in support, to defer adoption of the problem statement and issue charge to the MIC's March meeting to allow for more time to review the revisions.

In a white paper that PJM's Keyur Patel presented to the MIC, PJM stated that applying multiconfiguration modeling to its enhanced combined cycle model would allow for the MCE to capture the characteristics of individual resources and improve their dispatching. The number of configurations and schedules combined cycle units can present could lead to exponentially increasing times for the engine to complete optimization calculations.

PJM believes the best solution would be to adopt a design that would only enter one schedule to the MCE for commitment, according to the white paper. In seeking to limit the scope, the paper said that PJM is seeking to resolve the calculation issue while minimizing the impact to the current market rule.

Patel also said PJM is on a time crunch to reach a solution by the third quarter, when GE is set

PJM Director of Stakeholder Affairs Dave Anders speaks during the Market Implementation Committee meeting Feb. 9. | *© RTO Insider LLC*

# PJM News

to begin incorporating the RTO's guidance into a new software package.

Tyler argued that PJM's preferred solution of using a specific and flawed predefined formula for schedule selection would weaken market power mitigation rules and fail to address issues with their implementation that the IMM has identified for many years.

## Stakeholders Consider Recognition of Local Impacts to Net CONE

PJM *presented* a first read of the updated default gross cost of new entry (CONE) and avoidable cost rate (ACR) figures it is proposing through its quadrennial review. The new parameters will be used for the 2026/27 delivery year.

All resource types, except storage, would see their gross CONE figures increase, largely because of the Inflation Reduction Act's changes to the investment tax credit (ITC) and new reference resources used for combined cycle and onshore wind resources.

The main changes to gross ACRs proposed are the addition of steam oil and gas as a new resource type, additional data from the Nuclear Energy Institute on nuclear costs, and refined property tax and insurance costs. Single-unit nuclear generators were the only resource type to see a decrease in default ACR.

Gas resources would see the largest increase under the new numbers, with combined cycle units increasing to $540/MW-day of nameplate output from the 2022/23 gross CONE of $320, a nearly 69% increase. Combustion turbines would go up to $427/MW-day from $294, a 45.2% increase.

## Local Considerations for Net CONE

Stakeholders also discussed their interests and goals as they consider whether to allow PJM to include state and local issues in the formation of net CONE.

The items added to the *interest identification* matrix include ensuring that the net CONE established for an area reflects the most environmentally restricted asset life; avoiding substantial changes to the methodology of setting the end figure without considering the impact to the variable resource requirement (VRR) curve; and ensuring that the role of net CONE and the VRR curve are consistent with state policies that impact the parameters.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said he supports having an estimate of the CONE for constrained locational deliverability areas (LDAs) in instances where there are environmental restrictions such as legislation or regulations reducing the asset life.

"The reason this issue has been brought up is because of what's been going on in Illinois and potentially in New Jersey," he said. "Clearly they're moving in the direction of a much cleaner fleet, and that eventually could have implications."

## First Read of PJM Proposal on Co-located Load

PJM *presented* a proposal to define market rules for load behind a generator's meter months after the MIC rejected two competing proposals from the Monitor and Constellation Energy and Brookfield Renewable Partners. (See "Limited Support for Co-located Load Proposals," *PJM MIC Briefs: Dec. 7, 2022*.)

The previous discourse around the proposals centered on their treatment of co-located load that is not directly interconnected with the wider PJM grid and whether the generator should be permitted to retain its capacity interconnection rights (CIRs) for the portion of its output that serves that load.

Constellation argued that when the behind-the-meter load is highly interruptible and the generator can quickly shift its output back to the grid to fill its capacity obligations, it should be permitted to retain its CIRs.

During a first read of the RTO's proposal Wednesday, PJM's Lisa Morelli said generators would be able to retain their CIRs under such an arrangement, but the generator would be subject to ancillary services charges, such as black start, regulation and reserves, for the load. Even without a direct connection to the grid, Morelli said it's PJM's belief that the load indirectly benefits from those ancillary services through the generator.

PJM's Tim Horger said that if a generator and co-located load would not be able to operate independently of the grid, it is reliant on the grid and should have to pay the charges.

Constellation's Jason Barker said the company is opposed to the proposal, saying it effectively requires host generators to pay for ancillary services that PJM attributes to retail load, who are not PJM members.

Adrien Ford, of the Old Dominion Electric Cooperative, said she is opposed to allowing generators with co-located load to retain the output earmarked for the load and said PJM is trying to draw parallels between co-located load and behind-the-meter generation. She also said there has not been adequate weigh-in on whether co-located load is under FERC or state jurisdiction.

Monitor Joe Bowring indicated his surprise that PJM was now taking the initiative to support Constellation's proposal, given that it had received no stakeholder support in the RTO's poll and, he argued, would undermine markets.

## No Consensus on Changes to MSOC

Stakeholders were divided on changes that could be made to the marker seller offer cap for the 2025/26 Base Residual Auction to reflect the impact of December's Winter Storm Elliott. Much of the discourse was in line with the discussion at the Resource Adequacy Senior Task Force's Jan. 31 meeting, with stakeholders stating that they want additional information about how the 277 performance assessment zones on Dec. 23 and 24 will affect units' Capacity Performance quantified risk (CPQR) and related parameters. (See *PJM Stakeholders Discuss Capacity Market Changes After Winter Storm*.)

Jeff Whitehead of GT Power Group said market sellers currently have no insight on how their unit-specific offer caps will be evaluated by the Monitor and PJM. Without a firm understanding of what the status quo looks like, he said it is difficult for stakeholders to start working on solutions.

Bowring said it is fairly simple to include the data from the storm into the IMM's assessment of their risk, but that risk will vary widely for individual generators, preventing him from speaking in general terms. He encouraged generators to reach out to the Monitor for unit-specific information, but he said no generators had contacted it yet.

Bowring said that for some units, the impact of Elliott would be to reduce their CPQR risk, while for poorly performing resources, the impact would the opposite. "On average, the impact of Elliott on CPQR risk is relatively small. This is the first significant event since the introduction of the Capacity Performance market design."

PJM's Dave Anders said implementing changes in time for the 2025/26 BRA, scheduled for June, would have to follow a tight timeline with two possible pathways: delaying the auction, or keeping the bid and clearing timing and seeking FERC approval to alter the pre-auction timeline. Wrapping up Wednesday's discussion, Anders said he had not heard a preference for either option. ■

*— Devin Leith-Yessian*

# PJM PC/TEAC Briefs

## Planning Committee

### Update on 2022 Cost Allocation

VALLEY FORGE, Pa. — An error in the power flow case for several generators caused minor impacts to the 2022 annual cost allocations and zonal charges for the units, according to a *presentation* PJM's Grace Niu gave at the Feb. 7 Planning Committee meeting (*ER22-702*).

The error affected zonal allocations for 28 projects in 14 regions, with changes being below $1 million for all but three. Baltimore Gas and Electric saw its charges drop by $5.56 million, while APS increased by $1.66 million and Dominion went up by $2.62 million. Liu said the next steps are a FERC filing to make adjustments to the tariff to avoid similar incidents in the future.

### Stakeholders Approve New TO/TOP Matrix

Stakeholders endorsed *proposed revisions* to the Transmission Owner/Transmission Operator (TO/TOP) Matrix, which defines the tasks TOs and PJM are accountable for to comply with NERC reliability standards. Gizella Mali, TO/TOP Matrix Subcommittee chair, said the changes do not add any new standards or remove any retired standards and contain only minor revisions identified in the subcommittee's review.

The changes include updated document titles, versions and sections, as well as hyperlinks to reference tabs.

## Transmission Expansion Advisory Committee

### Dozens of Transmission Projects Canceled with Beaver Valley Extension

PJM's Phil Yum *reviewed* the baseline impact of First Energy's March 2020 announcement that it will no longer deactivate its Beaver Valley Nuclear Power Station, a two-unit 1,872-MW generator in Shippingport, Pa. (See *Beaver Valley Nuclear Plant to Stay Open.*)

Dozens of transmission upgrades had been identified in PJM's Regional Transmission Expansion Plans (RTEP) since the company's 2018 announcement that it intended to deactivate three of its nuclear facilities, including Beaver Valley. First Energy has also canceled the deactivation requests for the other two generators identified, Davis Besse and Perry Nuclear Generating Station.

PJM Senior Manager of Transmission Planning Sami Abdulsalam speaks during the Transmission Expansion Advisory Committee meeting Feb. 7. | © *RTO Insider LLC*

The reinstatement of Beaver Valley has led PJM to cancel 22 baseline upgrades in the APS zone, four in the American Transmission Systems Inc. zone and five in the Penelec zone.

### PJM Reviews Baseline Project Proposals

Dominion *proposed* two solutions totaling $17.8 million to address an overload identified at its 230/115-kV Bremo transformer in the 2027 RTEP light load case. PJM's preferred solution is to rebuild the Bremo-Fork Union 230-kV line with double circuit structures, achieving a summer rating of 1,573 MVA and disconnecting the line between the Bear Garden substation and Bremo to extending the line 1.6 miles to instead terminate at the Fork Union. The $10.09 million proposal comes with a projected in-service date of Nov. 1, 2027.

The proposal includes the potential to retire the Bremo substation and reterminate all its lines at Fork Union if there is sufficient headroom in the future. Dominion's second proposed solution would be to retire the Bremo substation now, relocate its lines to Fork Union and install three additional transformers at the substation at a $35.17 million cost.

Dominion also proposed a $7.71 million solution to a 300-MW load drop violation identified at its Evergreen Mills substation. The project would cut the Brambleton-to-Poland Road 230-kV line into two new lines that would run between the three substations, with Evergreen Mills in the middle. Approximately 0.59 miles of new line would be required to cut-in Evergreen Mills, with a total cost of $7.71 million. The project has an estimated in-service date of June 1, 2027.

### Supplemental Projects

American Electric Power *proposed* a $154.53 million supplemental project to rebuild 46.1 miles of 345-kV line with deteriorating wood H-frame structures, some of which have broken in the past and caused conductors to fall to the ground. The faltering equipment is along AEP's 51.1-mile Conesville-Bixby line in Ohio and is a major source of transmission into the greater Columbus area, making deactivation unviable.

Degrading of the laminated crossarms is a particular concern, with inspections showing decay and rot in the wood. AEP said there are few ways of identifying decay before it causes a loss of functionality and that, paired with the prevalence of delaminated crossarms on the line, many of the failures have "historically been catastrophic in nature." The Conesville-Bixby line is the only in AEP's eastern footprint that continues to rely on laminated wood.

Dominion *presented* two supplemental projects totaling $138 million to resolve two thermal violations at its Bristers substation in Virginia and on the line to the Nokesville substation. The first proposal would reconductor about 9.2 miles of the line between the two substations with higher capacity equipment to achieve a minimum normal summer conductor rating of 1,573 MVA at a $23 million cost, according to the company's presentation to the TEAC.

The second half of their proposal is to install two 1,400-MVA 500/230-kV transformers and accompanying equipment at the Vint Hill substation and expand the site to the north to provide adequate space for the equipment. Dominion would also cut and loop Vint Hill into the 500-kV lines between the Loudoun substation and the Meadowbrook and Morrisville substations, as well as cut and loop the Rollins Ford-Remington CT 230-kV line to Vint Hill. The work comes with an estimated $115 million cost. ■

## Company News

# WEC Touts Renewable Investment in Year-end Earnings

*By Amanda Durish Cook*

WEC Energy Group's leadership this month plugged the billions they will spend on transforming their utility's energy mix in a year-end earnings call.

WEC *reported* fourth-quarter earnings Feb. 2 of $252.7 million ($0.80/share), compared to the $224.2 million ($0.71/share) it netted for the same period last year. The utility recorded year-end net income of $1.4 billion ($4.45/share), compared to the $1.3 billion ($4.11/share) over 2021.

WEC Energy Group Executive Chairman Gale Klappa told financial analysts that the company plans to spend $20.1 billion over the next five years, up from $17.7 billion it initially *targeted* in 2022. He said the spend, as outlined in an *updated* environmental and social governance progress plan, is the "largest five-year investment plan in our history."

Klappa said management expects the plan to drive compound earnings growth of 6.5% to 7% per year through 2027.

The plan will position WEC for "efficiency, sustainability and growth," Klappa said. The plan includes more than $7.3 billion in new renewable investments in solar, wind and battery storage, a "major commitment to renewable projects" that is now a cornerstone of the utility, he said.

WEC announced last month it will *acquire* an 80% interest totaling $250 million for the first phase of the 250-MW Samson Solar Energy Center in northeast Texas.

WEC CEO Scott Lauber said the utility's $160 million, 80-MW Red Barn wind farm in Wisconsin will come online in the next few months and its Badger Hollow II solar facility and the Paris Solar Battery Park in Wisconsin will likely go into service within the year, contingent on panel delivery.

Lauber noted that the Wisconsin Public Service Commission last year approved WEC's purchase of the $451 million Darien Solar Energy Center. Its 225 MW of solar capacity and 68 MW of battery storage is expected online in 2024.

Laubner said the 300-MW Thunderhead Wind Farm in Nebraska is now in service; WEC has a $338 million, 80% stake in the project. He said he expects that the utility will finalize a $412 million, 90% interest in the 250-MW Sapphire Sky in Illinois in the coming weeks.

WEC plans to achieve carbon neutrality by 2050 and phase out coal use by 2030 so that it's only a backup fuel. ■

| *WEC Energy Group*

Company News

# Dominion Energy Sees Loss in Q4; Earnings Fall for 2022

## *Utility's Business Plan Review Waiting for New Laws on Virginia's Regulatory Structure*

*By James Downing*

Dominion Energy on Wednesday announced a net loss for the fourth quarter of $42 million and net income of $994 million for the entire year of 2022.

Earnings were down according to GAAP, but operating earnings for the fourth quarter were $903 million, up from $752 million a year earlier. Differences between the two were from the impairment of some nonregulated solar generation facilities, the market-to-market impact of economic hedging activities, gains and losses on nuclear decommissioning trust funds, regulated asset retirements and other adjustments.

The firm delivered earnings and dividend growth in line with its guidance, while providing safe, reliable and affordable energy to consumers, CEO Robert Blue said on an earnings call.

"We're very focused on ensuring that our customers are not priced out of the significant long-term benefits that will result from our decarbonization and resiliency investment programs," Blue said. "On that same theme, 2022 was a significant year in terms of advancing our regulated, decarbonization and resiliency strategy."

The Virginia State Corporation Commission approved several investment programs eligible for rate riders, including the company's offshore wind farm, new solar and storage facilities, grid upgrades, and license renewals for its four nuclear reactors in the state at North Anna Power Station and Surry Power Station.

Additional rider-eligible investments currently under SCC review include additional solar and storage projects in Dominion's third annual clean energy filing, and high-voltage transmission needed to serve growing customer demand and data center load.

Dominion also owns nuclear plants in other states, including the Millstone Nuclear Power Plant in Connecticut that is under a long-term contract with the state that proved beneficial to customers, Blue said, saving them $300 million last year as power prices in New England were up. The plant is important to the entire region of New England, especially in terms meeting its states' goals of decarbonization reliably, he said.

Dominion CEO Robert Blue | *© RTO Insider LLC*

"We see the possibility of being able to take action with policymakers to give us the certainty we would need in order to extend the life of millstone and have that valuable resource for New England for some time to come," Blue said. "We don't have, as yet, a specific approach to that, but we're certainly interested in engaging with policymakers on that."

Dominion has been involved in discussions in Richmond, Va., over the future of how it will be regulated in the state, with multiple bills moving through the legislature this session, which runs until Feb. 25. The legislature is working on two bills that Blue highlighted on the earnings call: one with a series of changes to how the SCC sets its rates, and another that would allow Dominion to get a partner to help it build its 2.6-GW Coastal Virginia Offshore Wind project.

The Virginia Senate passed Dominion-backed legislation on the SCC's ratemaking authority in a 27-13 vote on Feb. 7, with all but two of the "no" votes coming from Democrats.

*Senate Bill 1265* included language about recovering deferred fuel costs, requiring the SCC to set its rates at the average of a peer group of other large utilities in the South and removing $350 million from rate riders and putting them into base rates. Its companion bill in the House of Delegates, *House Bill 1770*, passed by a 52-47 vote Feb. 7 as well, with the no votes coming from Democrats.

The legislature has to work out any differences between the two bills and others involving the SCC's authority. Gov. Glenn Youngkin would then have until March 27 to sign, veto or offer amendments to legislation, which could kick the process back to the legislature that meets on April 12 to deal with the governor's actions. Youngkin then has until mid-May to act on any legislation passed or amended during that reconvened session a month prior.

Blue resisted offering any predictions on what would ultimately come out of the process on the earnings call. Dominion is working on a review of its overall business, but the direction that will take will be dependent on legislative outcomes in Virginia.

"Having a clear and definitive understanding of the future Virginia regulatory construct is a key input for the business review," Blue said. "Therefore, legislation timing will influence the cadence at which we're able to share more details about the business review in the future." ■

## Company News

# Duke Energy Meets 2022 Targets, Takes Hit on Renewables Sale

### *CEO Highlights Plans to Spend on Regulated Renewables*

*By James Downing*

Duke Energy on Thursday reported higher earnings for the full year of 2022 because of higher electricity volumes, more favorable weather and rate case contributions.

The company reported adjusted earnings of $5.27/share, compared with $4.99/share in 2021, though unadjusted earnings came in at $3.33/share, compared to $4.94/share the previous year.

"We achieved results solidly within our updated guidance range while making significant progress on our strategic goals, responding to external pressures and delivering constructive outcomes across our jurisdictions," CEO Lynn Good said during an earnings call.

The company is in the process of selling Duke Energy Sustainable Solutions, a non-regulated renewables developer that has 5,319 MW worth of projects spread around the country, and it took an impairment charge of $1.3 billion related to the sale.

"I think the thing to recognize on an impairment charge is it's an accounting adjustment that's really driven by the earnings profile of renewables where a lot of the profit sits in the early part of the life, [and] you then depreciate it over a longer period of time," Good said. "So, when you make a decision to exit before the end of the useful life, you've kind of set yourself up for an impairment."

Duke announced plans to sell its commercial renewables business in November, and it hopes to complete that process later in 2023.

While it is getting out of the business of developing competitive renewable projects, most of Duke's expected spending in the coming years will be on shifting its regulated utilities to cleaner generation, with a $65 billion capital plan for all of its regulated businesses.

In North Carolina, the next steps for that capital spending have been laid out in the firm's first carbon plan, which was approved by state regulators late last year. The state approved Duke to build 3,100 MW of solar and 1,600 MW of energy storage in the near term, with limited development activity for longer-term projects, including small modular nuclear reactors.

Duke Energy CEO Lynn Good | *Duke Energy*

The North Carolina Utilities Commission also authorized Duke to plan for about 2,000 MW of new natural gas plants that Good said are needed for reliability.

"Through its order, the commission reinforced the importance of maintaining a diverse generation mix while conducting an orderly clean energy transition and was clear that ensuring replacement generation is available and online prior to the retirement of existing coal units is a shared priority," Good said.

The carbon order supports Duke's own capital plan, giving it the clarity that it needs to advance critical near-term investments, she added. Duke plans to spend $4.7 billion over the next three years, largely on transmission and distribution enhancements, though with some earmarked for the solar and storage approved by the NCUC.

While Duke is focused on solar and storage in the short-term, Good said the company would need to build 10 to 15 GW of "zero-emitting load-following resources in the late 2030s, or 2040s.

"That could be hydrogen; it could be small modular reactors; it could be [carbon capture, utilization and storage]; it could be longer-duration storage," Good said. "So, the key being, again, though, we're not going to invest until they are affordable for our customers, and we can invest at the commercial scale necessary to make a difference."

Duke is spending time on small modular nuclear reactors because it is the largest "regulated" operator in the country and is in part of the world where the technology is generally viewed favorably, Good said.

The company has also worked with neighboring utilities in the Southeast on a hydrogen hub because Good expects it will have plenty of extra solar energy that could be used to produce the fuel.

"We're not ready to put our finger on any specific technology as the solution," she added. "But we are advancing our work, piloting, advising, working as actively as we can to make sure these technologies are developing at pace so that when we do need them and are ready to invest, there will be something that makes sense for our customers." ■

## Company News

# SEPA Lauds Utilities in 2023 Transformation Leaderboard

*By Amanda Durish Cook*

The Smart Electric Power Alliance (SEPA) last week released its latest assessment gauging utilities' progress and identifying actions to accelerate the industry's transition to a carbon-free energy system.

SEPA recognized a dozen utilities in its *2023 Utility Transformation Challenge* as being ahead of the curve in the clean energy transformation. Most of those are in California, with glowing reviews to Palo Alto Utilities, Pacific Gas and Electric, Sacramento Municipal Utility District and Southern California Edison.

The organization said Snohomish County Public Utility District in Washington and Portland General Electric in Oregon also made good progress.

On the East Coast, SEPA praised Vermont's Green Mountain Power, New Jersey's Public Service Enterprise Group and National Grid, which supplies New York and Massachusetts. Austin Energy, the Texas city's municipal provider, and Minnesota-based Xcel Energy were the only commended utilities between the two coasts.

Those recognized had to complete SEPA's Utility Transformation Challenge survey to be considered. The organization said it collected data from 118 utilities in 41 states, representing more than half of U.S. customer accounts.

SEPA said the utilities that made its final cut supply "a substantial percentage" of their retail energy with clean resources, including energy efficiency and demand response; have strong commitments to carbon reduction; feature publicly available climate-adaptation strategies; and have plans for an equitable energy transition.

It said it's also noticing an asymmetrical transition to clean energy, though utilities have rolled out more aggressive decarbonization targets, better climate action plans, improved visibility into their distribution systems, and have made strides to a more equitable power system.

The group said 66% of utilities responding to its survey have expanded their clean energy sources and 80% have a carbon-reduction goal in place. SEPA said it expects those goals will take decades to achieve and recommended utilities establish interim reductions goals.

"Utilities will need to navigate supply chain disruptions, transmission and interconnection bottlenecks, the effects of natural disasters on resource acquisition and costs," SEPA said, adding that utilities cited labor shortages and supply chain hitches for delaying new renewable energy. Those scuttled plans have led to 40 coal plants keeping 17 GW of capacity online past their planned retirement dates, SEPA said.

It said 69% of respondents are piloting or investing in early stage, carbon-free technology, including hydrogen, long-duration energy storage, floating offshore wind, tall wind turbines, small modular nuclear reactors, and carbon capture and storage.

SEPA said gridlocked interconnection queues have also hampered utilities trying to bring renewable generation online. It said PJM's current backlog is preventing it from reviewing new interconnection requests until early 2026.

The organization also said droughts in the West contributed to a 14% reduction in hydroelectric generation from 2020 to 2021 and continue to threaten the carbon-free resource. SEPA warned that some utilities may be forced to purchase fossil-fired energy to replace the output.

To avoid that, SEPA recommended utilities use more demand-side management programs and pull together climate investment plans that consider the impact of climate change on operations. ■

Sheep vegetation management at the Rancho Seco Solar 2 site | *Sacramento Municipal Utility District*

# Company Briefs

### FirstEnergy Sells Stake in Subsidiary

FirstEnergy last week announced its decision to sell an additional 30% ownership interest in its FirstEnergy Transmission subsidiary to a Brookfield Asset Management infrastructure fund.

After market hours on Feb. 2, FirstEnergy announced a deal to divest the stake in FirstEnergy Transmission to Brookfield Super-Core Infrastructure Partners LP for $3.5 billion cash.

The sale price is 39 times the transmission business' earnings over the past 12 months and greater than 25 times its forecast 2025 earnings, FirstEnergy said in an investor presentation. The company said the deal is "equivalent to issuing common equity at $93 per share."

More: *S&P Global*

### Ford to Announce $3.5B Battery Plant in Michigan

Sources say Ford Motor is set to announce plans to build a $3.5 billion lithium iron phosphate battery plant in Michigan.

Ford is expected to own and operate the plant with China's Contemporary Amperex Technology as a technology partner to help develop the batteries.

More: *Reuters*

### European EV Charger Manufacturer to Build Factory in NC

Finland-based Kempower last week announced it will build a $41 million factory in Durham County, N.C.

The company manufactures charging stations for electric vehicles.

The Department of Transportation's National Electric Vehicle Infrastructure Program aims to ensure that there are at least four fast EV chargers every 50 miles along major highways.

More: *News & Record*

# Federal Briefs

### Biden Admin Announces $2B Loan for EV Battery Manufacturing

The Biden administration last week announced it would issue a $2 billion loan to a battery manufacturing facility as it looks to bolster the country's supply chain for EVs.

The loan would go to Redwood Materials for the expansion of a battery materials facility in McCarren, Nev. The facility recycles batteries from electronics and uses the materials to make components of EV batteries.

Redwood Materials CEO J.B. Straubel said the facility will be able to produce materials for about a million EVs each year.

More: *The Hill*

### Public Comment Period on MVP's Path Through National Forest Extended

The U.S. Forest Service last week extended the deadline for public comments on the Mountain Valley Pipeline's proposed route through the Jefferson National Forest until Feb. 21. A 45-day public input session would have expired on Feb. 13.

The move came after individuals and organizations — many of them opposed to the natural gas pipeline crossing a 3.5-mile segment of the forest in Giles and Montgomery Counties in Virgina and a small portion in Monroe County, West Virginia — requested more time.

More: *The Roanoke Times*

### Solar Titan USA Faces Court Order amid Multistate Investigation

U.S. District Court Judge Clifton L. Corker last week granted the requests of attorneys general for Tennessee and Kentucky in seeking a protective order over Solar Titan for "pervasive and ongoing deceptive and unfair business practices."

The complaint said Solar Titan "drastically exaggerates the amount of electric utility bill savings consumers will experience." Furthermore, numerous customers who say they spent thousands of dollars claim that Solar Titan has failed to deliver on promises for its solar products.

Under the order signed by Corker, Solar Titan must let receiver Richard Ray "oversee and manage the company."

More: *WBIR*

### Report: Chances of Coal Being Phased out by 2050 are 1-in-20

Current policies give just a 1-in-20 chance of coal plants being phased out by 2050, according to a study published last week in the journal *Nature Climate Change*.

The authors of the report focused on two substantial loopholes. First, the agreement from the 2021 U.N. climate change conference allows the possibility that coal plants can be somehow "abated," perhaps by using currently unproven technologies to capture and store carbon dioxide. Second, the signatories avoided language that would have committed countries to "phase out" coal, instead committing only to reduce use along an unspecified timeline.

The researchers also found that the alliance has faced problems ensuring that member countries are following through on their commitments.

More: *The Hill*

### Judge Dismisses Lawsuit over TVA's Long-term Deals

U.S. District Judge Thomas L. Parker last week dismissed a lawsuit by environmental groups that challenged how the Tennessee Valley Authority signs local power providers to 20-year contracts.

Parker sided with TVA in that the environmental groups did not have legal standing. Parker also found that TVA "acted reasonably" under a law requiring it as a federal agency to assess environmental effects of major projects before making decisions.

The lawsuit filed in August 2020 argued that 20-year deals signed by most of TVA's customers lock the distributors into exclusive contracts and "will forever deprive distributors and ratepayers the opportunity to renegotiate with TVA to obtain cheaper, cleaner electricity."

More: *The Associated Press*

### Climate Bill Creates 100K Clean Energy Jobs

An analysis released last week by environmental group Climate Power showed that companies announced 101,036 new jobs in carbon-free energy and more than 90 new clean energy projects since the passage of the Inflation Reduction Act.

The new jobs are being created by the wind, solar, batteries and electric vehicle industries and include electricians, mechanics, construction workers and technicians.

Climate Power analyzed publicly announced or reported projects and the jobs companies project they will bring. Because the group monitored only public announcements, it is possible additional jobs were created that were not analyzed as part of the report.

More: *The Hill*

# State Briefs

## ARKANSAS

### Legislation Threatens to Hamstring Rooftop Solar Expansion

House Bill 1370, introduced last week by Rep. **Lanny Fite** (R-Benton), would end the state's policy that requires owners of solar arrays and other renewable sources to be compensated at the regular retail rate for excess generation.

The state's largest electricity providers, Entergy Arkansas and Arkansas Electric Cooperatives Corp., say the current policy unfairly shifts the cost of electricity onto customers who don't want or can't afford solar or other renewable systems.

Utility customers who fed excess electricity to the grid received 10 cents per kWh for their net generation through 2022. A Public Service Commission order allows existing pacts between net-metering customers and utilities to remain in place for 20 years.

More: *Arkansas Advocate*

## CALIFORNIA

### BLM Approves Desert Quartzite Solar Project

The Bureau of Land Management last week approved the construction of the Desert Quartzite solar project in Riverside County.

The 300-MW project will result in a private infrastructure investment of $1 billion.

More: *Bureau of Land Management*

### Sunrun, PG&E Partner on Residential Virtual Power Plant

Residential solar and battery installer Sunrun has partnered with Pacific Gas & Electric to create a new virtual power plant (VPP) combining up to 30 MW of new and existing home PV and battery systems for grid reliability.

Sunrun will enroll up to 7,500 new and existing home PV and storage systems in PG&E's service area into the Energy Efficiency Summer Reliability Program. The VPP will be able to dispatch 30 MW to lower the cost of power during peak demand and reduce grid strain.

The Public Utilities Commission approved the plan on Jan. 30.

More: *Energy Storage News*

## GEORGIA

### Bill Would Make Attacking Critical Infrastructure a Felony

Legislation introduced in the House of Representatives last week would establish the crime of "interference with critical infrastructure" with violators serving up to 20 years in prison.

Under the legislation, critical infrastructure includes electricity, water, sewers, telecommunications, internet, public transportation and public transit systems, hospitals, ambulances, emergency medical and rescue services, the military, police, Coast Guard, and prison and fire services.

More: *Capitol Beat News Service*

## MICHIGAN

### Co-op Lands $262.8M Federal Loan for Electric, Fiber Infrastructure

The Great Lakes Energy Cooperative last week secured a $262.8 million loan from the U.S. Department of Agriculture to build and improve 438 miles of grid infrastructure and 2,420 miles of fiber network.

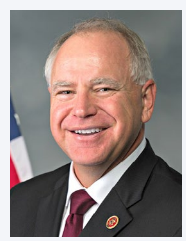
Nearly $183 million will go to various smart grid projects. Also, in addition to fiber infrastructure, the loan will help finance renewable and efficiency projects.

The grant was issued through the USDA's Rural Development Electric Loan Program.

More: *MiBiz*

## MINNESOTA

### Walz Signs Carbon-free Energy Bill



Gov. **Tim Walz** last week signed a bill that requires the state's utilities to transition to 100% carbon-free energy sources by 2040.

Minnesota joins 21 other states, along with the District of Columbia and Puerto Rico, that have set goals to reach 100% carbon-free energy generation by 2050. In 2021, 29% of the state's electricity came from renewable sources.

Xcel Energy and Minnesota Power, the state's largest utilities, have already pledged to reach carbon-neutrality by 2050.

More: *MPR News*

## NEW MEXICO

### Bill Passes to Spend $13M, Create Division to Shift State Away from Oil, Gas

The House Government, Elections and Indian Affairs Committee voted 6-3 to pass a bill that would create an Economic Transition Division within the state's Economic Development Department and appropriate $13.4 million to fund the division and provide support for local communities during economic transition away from dependence on fossil fuels.

Policies such as the 2019 Energy Transition Act set benchmarks for the state leading to 100% carbon-free energy by 2045. HB 188 was introduced as an effort to advance that goal and was sent to the House Appropriations and Finance Committee for further consideration.

New Mexico is second in the nation in oil production, following only Texas, and is usually in the top 10 for natural gas.

More: *Carlsbad Current-Argus*

### Bill Would Require 75% of State-owned Vehicles be Battery Powered

Senate Bill 30, sponsored by Sen. William Soules (D-37), would require 75% of all state-purchased vehicles be electric.

If passed, the bill would require the purchases by Transportation Services Division of the New Mexico General Services Department and call on the division to establish a plan to do so by the end of 2023.

The bill was sent to the Senate Finance Committee for further discussion.

More: *Carlsbad Current-Argus*

## NORTH DAKOTA

### PSC Approves Expansion of Basin Electric's Pioneer Station

The Public Service Commission last week approved the expansion of Basin Electric's natural gas Pioneer Generation Station in Williams County.

Basin will add six 18.8-MW "reciprocal internal combustion engines" and two simple cycle combustion turbines at a cost of $788 million. It will increase the station's output to 583 MW.

Construction is expected to begin later this year.

More: *Prairie Public Broadcasting*

## OREGON

### Eugene Bans Natural Gas in New Low-rise Residential Buildings

The Eugene City Council last week voted 5-3 to pass a resolution that will ban new natural gas infrastructure in new low-rise residential buildings.

The ordinance applies to building permits submitted on or after June 30 and does not affect existing buildings. Developers will have to use electric appliances and power when building new residences of three stories or less.

More: *KLCC*

### Future Portland Apartments Required to Have EV Charging Stations

The Portland City Council last week unanimously approved an ordinance that will require future multiunit housing developments with on-site parking to include EV charging stations.

The amendment to the city's zoning code will require new housing complexes to provide a charging station at every parking space if there are six or fewer spaces. Buildings with seven or more spaces must include charging stations at 50% of parking spots.

The ordinance will go into effect March 31.

More: *KOIN*

## VERMONT

### State Becomes First to Ban CFL Lightbulb Sales

The Department of Environmental Conservation last week banned the sale of compact fluorescent lamp bulbs, effective Feb. 17.

The DEC moved to restrict the sale of "screw-based mercury-containing compact fluorescent lamps" in Feb. 17, 2022, but gave retailers and distributors one year to move any remaining inventory.

More: *The Hill*

## VIRGINIA

### Halifax County Board Approves Solar Project

The Halifax County Board of Supervisors last week unanimously approved a permit for Sedge Hill Solar's solar farm.

Sedge Hill Solar will be situated on 11 parcels of land, with 550 of the total 1,061 acres to be used for solar panels.

The board also approved a solar siting agreement, as well as the legal status of the solar site plan.

More: *The Gazette-Virginian*

## WASHINGTON

### Lawmakers Seek to Ban Utility Shutoffs During Extreme Heat

A bill going through the legislature would make it illegal for utilities to shut off power during heat waves, defined as temperatures above 90 degrees.

Rep. Sharlett Mena (D–Tacoma) pointed to a 2021 heat wave when temperatures reached triple-digit, all-time highs three days in a row. The state Department of Health said nearly 160 deaths were reported in a month and emergency room visits were 69 times higher than previous years.

It is already illegal for state utilities to shut off power due to "non-payment" during extremely cold weather.

More: *KING-TV*