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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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FERC & Federal

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COVER: Operator inside the ISO-NE control room | *ISO-NE*

RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

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In this week's issue

FERC/Federal News

After a Quarter Century, Industry Experts Still Split on Restructuring

By James Downing

Ask 10 experts whether RTO markets and electricity deregulation lead to lower prices and you are liable to get 10 different answers.

Debates around the benefits of restructuring have been going on since the states started unbundling monopoly utilities a quarter century ago. A new skirmish arose on #energytwitter earlier this month in response to a *New York Times* article provocatively headlined "Why Are Energy Prices So High? Some Experts Blame Deregulation."

Citing an analysis of Energy Information Administration data by energy researcher Robert McCullough, the article says "California and the 34 other states that have deregulated all or parts of their electricity system tend to have higher rates than the rest of the country." (See sidebar, *A 'Deregulation' Debate by the Numbers*.)

Rorschach Test

RTO Insider reached out to a range of sources to get their thoughts on whether deregulation and organized wholesale markets have benefited customers.

Competition "is a Rorschach test," energy consultant Alison Silverstein told *RTO Insider*. "And you can manipulate numbers, particularly electric rates, to say anything you want to."

Former FERC Chair Pat Wood III | © *RTO Insider LLC*

Silverstein's old boss Pat Wood — who took over as chairman of FERC during the California Energy Crisis and chaired the Texas Public Utility Commission when that state started its journey to a fully deregulated, or restructured, wholesale and retail power market — is firmly in the pro-market camp.

"Competition on its worst day is better than I ever could be as a regulator on my best day," said Wood, who is now CEO of energy storage developer Hunt Energy Network.

Rate regulation is intended to ensure utilities with monopoly territories earn enough to attract investment while keeping prices affordable. No matter how talented regulators are, Wood said, "there's no way you can really substitute for the efficiencies and discipline of a market on pricing for customers."

Tyson Slocom, Public Citizen | © *RTO Insider LLC*

RTOs were created to lower costs to end-use consumers but have failed to do so, said Public Citizen's Energy Program Director Tyson Slocum. The states that did restructure started with higher prices to begin with for a variety of reasons.

"But those prices remain just as high or higher today than they did 20 years ago, compared

Continued on page 4

A 'Deregulation' Debate by the Numbers

By Robert Mullin and James Downing

PORTLAND, Ore. — When energy economist Robert McCullough greeted this reporter at a wine shop and deli in our shared Southeast Portland neighborhood, he joked about recently contributing to "quite a stir" in the electricity industry.

McCullough was referring to a high-profile article published in *The New York Times* Jan. 4 under the headline "*Why Are Energy Prices So High? Some Experts Blame Deregulation*," which set off a wave of criticism from industry insiders — much of it on #energytwitter.

"On average, residents living in a deregulated market pay $40 more per month for electricity than those in the states that let individual utilities control most or all parts of the grid. Deregulated areas have had higher prices as far back as 1998," the *Times* said.

Times Article Misses the Mark, Critics Say

Critics faulted the *Times* for conflating "dereg-

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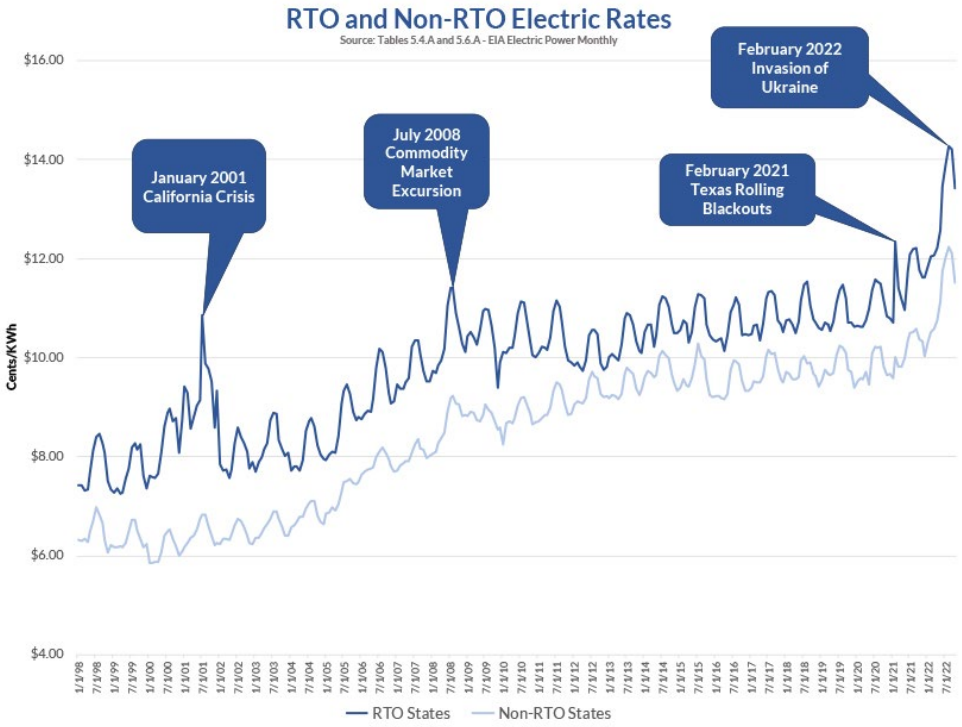

Graph compares the trend of retail electricity prices in RTO and non-RTO states from 1998 to 2022. | *Alexander MacKay and Ignacia Mercadal*

FERC/Federal News

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to other states," Slocum said. "So, what's clear is that RTOs are failing to deliver the promise of lower prices and that should be of great concern to FERC. If the entire purposes for doing something isn't happening, then you should probably investigate as to why."

Severin Borenstein, U.C. Berkeley | *U.C. Berkeley*

Plenty of others are somewhere in the middle with Severin Borenstein, a professor at the University of California Berkeley's Haas School of Business and a member of CAISO's board, whose *work* has found that it depends on other factors entirely.

"The reality is that if you procure power through a deregulated wholesale market, the marginal supply sets the price," Borenstein said in an interview. "Now, if gas prices are really low, you end up getting much better prices in a [competitive] wholesale market than you do in a regulated market."

Natural gas is the most common marginal fuel in ISO/RTO markets around the country, which means that generators burning it most often set the locational marginal price (LMP) for other generators. If gas prices are high, then the vertically integrated states have cheaper prices because their generation is not paid a single price, Borenstein said.

The issue of whether RTOs lead to consumer savings was a hot topic before the shale revolution, when gas prices were trading at $7-8/MMBtu some 15 years ago.

"PJM was in absolute crisis," said Public Citizen's Slocum. "There was serious consideration of whether or not it had all failed because gas, which was setting the marginal cost, was punishingly high."

The RTO model got "bailed out" by cheap natural gas from fracking, said Slocum. But now the markets are under strain again as gas prices were higher last year on average than any year since 2008, according to EIA.

Slocum and others also argue that the markets are under strain as renewables are growing, but many who spoke with *RTO Insider* argued that RTOs and their abilities to efficiently dispatch generation across a wide footprint are going to be key to making that transition happen affordably and reliably.

Economies of Scale

Scott Harvey, FTI Consulting | © *RTO Insider LLC*

"I think ISOs have led to huge reductions in cost," FTI Consulting's Scott Harvey said in an interview. "Particularly in MISO, SPP and the Western EIM, where there was no power pool before. Having the coordinated dispatch of the ISO allows the region to use all of the transfer capability of the transmission system."

Under the old rules, the available transfer capability used was a fraction of the total available — not because the people running the old utility balancing authorities were trying to keep the resource themselves, but because they had very limited views of where power was flowing, Harvey said. They had to make worst case assumptions because once the power started flowing, they had very limited abilities to change it even if they need to for reliability.

ISO-NE, NYISO and parts of PJM were already in tight power pools before their ISOs developed, but Harvey said PJM's expansion has led to major improvements.

"If you think back to the polar vortex of 2014, PJM actually got through it without any load shedding," Harvey said. "I doubt they could have if it was the old world with a bunch of fractionated utilities in the Midwest and Ohio."

The benefits of stitched together balancing authorities came up again in the recent cold snap over the Christmas holiday when PJM was again stressed but did not shed load while individual utilities in the Southeast did, Harvey said. (See *PJM Gas Generator Failures Eyed in Elliott Storm Review*.)

"I think ISOs have led to huge reductions in cost. Particularly in MISO, SPP and the Western EIM, where there was no power pool before."

—Scott Harvey, FTI Consulting

Former FERC commissioner and North Dakota regulator Tony Clark, who is now a senior adviser at Wilkinson Barker Knauer, agreed that a clear benefit of RTOs is that they drive scale, which is hugely important in the electric industry.

Time for a Change in the Pricing Model?

Former FERC Commissioner Tony Clark | © *RTO Insider LLC*

The other common feature that is often credited with driving savings is security constrained economic dispatch, but Clark has doubts about the benefits of the ISO/RTO pricing model.

"LMP pricing was designed around a system where most resources had very similar attributes," Clark said. "They weren't exact, but more resources were basically dispatchable, they were basically on demand. They might have longer, or shorter lead times, ramp times, things like that. But they tended to be dispatchable, and they tended to have a fuel cost, which is to say they have marginal costs."

Weather-dependent renewables are not dispatchable, and they have free fuel so they have no marginal costs. But under the current structure they get paid whatever the most expensive plant needed is paid, which tends to be a natural gas unit.

"Under that scenario, do consumers still benefit?" Clark said. "Or would they benefit from some sort of average cost pricing? It's a really interesting question."

The idea of average pricing in wholesale power markets, and any other commodity market, is based on a misunderstanding of how bidding works, said U.C. Berkeley's Borenstein.

"They wouldn't bid lower if they knew they were going to be paid their bid," he said. "They'd try to bid whatever the market clearing price is. The idea that everybody gets paid a uniform price is how commodity markets work, not just for electricity — for natural gas, for gold, for oats, for everything. There's a market price, and people will get paid that market price because they're selling a homogeneous good."

ISO/RTOs Share Some Things in Common, but Have Many Differences

While RTOs have some common characteristics, they also have marked differences.

FERC/Federal News

ERCOT also helps administer a fully deregulated wholesale power market, while ISO-NE, NYISO and PJM are dominated by states that have also opened their retail markets, though none have gone as far as Texas.

MISO and SPP are largely dominated by traditionally regulated utilities, while CAISO is somewhere in between with community choice aggregation and capped retail competition for large commercial, industrial and institutional customers.

Former Montana PSC Commissioner Travis Kavulla, now with NRG Energy | © *RTO Insider LLC*

Beyond those regulatory issues, the markets have very different resources, and that can muddle the studies claiming to find savings or increased costs from ISO/RTOs, said NRG Energy Vice President of Regulatory Affairs Travis Kavulla.

"It wouldn't matter whether New England was open to competition, or economically regulated at the moment; the fact of the matter is under either of those models it would be substantially exposed to the wholesale gas market," Kavulla said. "New England happens to be a place where policymakers have decided not to build a lot of gas pipelines to domestic sources of gas, and so they have effectively exposed themselves to the European gas market, the global natural gas LNG market."

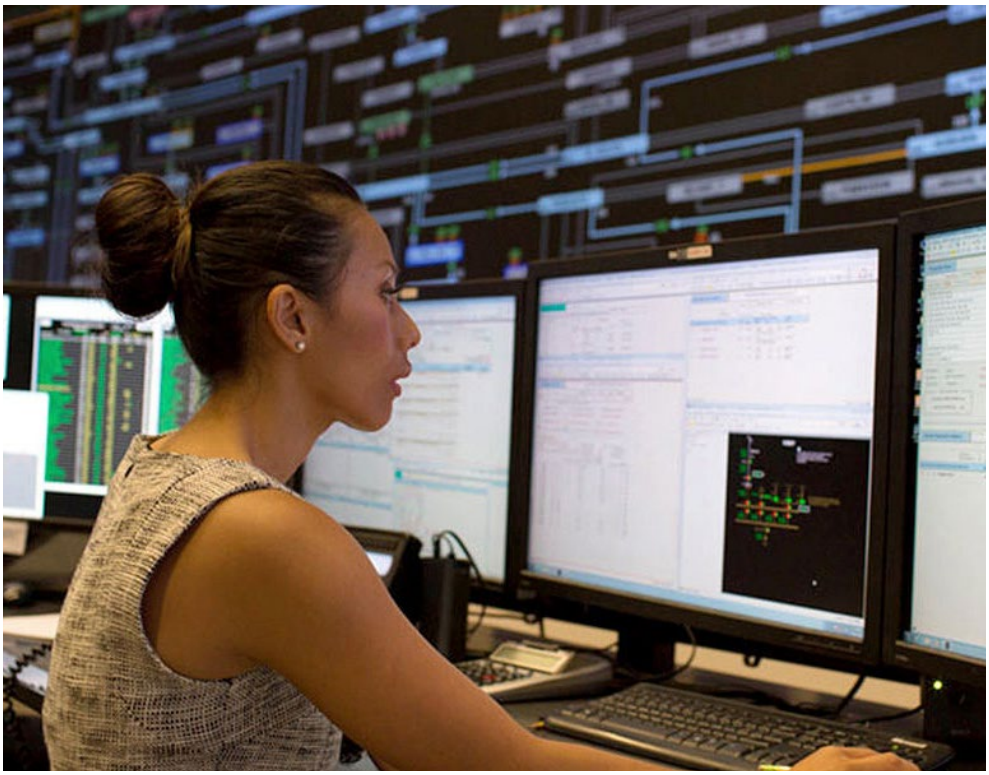
Studies will take those effects and impute them to competition, when it really has more to do with the policies of the New England states, Kavulla said. California is another odd duck to squeeze into studies, he said.

"I don't think any reasonable person would look at the amount of regulation and the amount of government policy related to the energy sector in California and conclude that it's quote, unquote deregulated," he added.

Retail Deregulation

Experts who spoke with *RTO Insider* were split on the benefits of full "deregulation" — where states have also opened their retail power markets.

Wood, who helped design the ERCOT market, still supports retail competition. The wide-open retail market in most of ERCOT is able to flow through the savings from wholesale competition to end-use customers. But in other states where utilities are still providing default retail service to customers it can be more of a muddle.



Operator inside the ISO-NE control room | *ISO-NE*

"I've definitely been on the record for 20 years or so about making sure these default providers don't suffocate retail competition," Wood said. "So, you either stick with wholesale competition only and you have a very clear way of passing those benefits of low-cost generation, or lower cost generation, being passed through … or you have robust retail competition, like we have here, where retailers compete with the other ones to get your business, and so, they have to pass through those [lower] costs through."

In between those two worlds, some middleman is likely to keep a share of any of the purported benefits of competition, he added.

Ralph Cavanagh, Natural Resources Defense Council | © *RTO Insider LLC*

The Natural Resources Defense Council's Ralph Cavanagh was against the idea of retail competition when California was considering deregulating in the late 90s, and he recalls a debate with an executive at Enron on the issue.

"I asked the question publicly: What is in this for my mother?" Cavanagh told us. "To which his response was, 'for the first time in history, your mother is going to be able to hedge her fuel price risks in the marketplace.' Mercifully, people laughed at that."

Cavanagh said small customers generally do not want to spend the time to learn about fuel price risks, though large commercial, industrial and institutional customers can benefit from such options.

"It is worth recalling that even large, sophisticated customers got swamped by the collapse of the California retail markets in 2000 and 2001," he added.

Coordination Can Help Green the Grid

But when it comes to wholesale competition, Wood and Cavanagh are on the same page. The elimination of utility monopolies over generation has been going on since the 1970s, and no one is seriously considering reversing that, said Cavanagh.

The West outside of California is one of the two main areas, along with the Southeast, that lack an organized market. But in the former that is changing, and Cavanagh said it must do so to reliably transition the grid to a cleaner future. The West would not have made it through the massive heatwave this past September without major cooperation, where Arizona helped California and California helped Idaho maintain reliability.

FERC/Federal News

"It became obvious to everyone that nobody cared what the political color of the state was," Cavanagh said. "There's a common interest to a fully functioning regional grid to which we are all connected."

The CAISO-run Western Energy Imbalance Market has already expanded to cover most of the Western Interconnection, and it has saved billions of dollars so far.

"The most important thing we have to do now is to get the California legislature to open a path to fully independent governance for the California ISO," Cavanagh said.

CAISO covers roughly one quarter of the generation and demand for power in the Western grid. Cavanagh said it was the best positioned entity to run the entire interconnection. SPP, however, is also fighting for a role in the Western Interconnection. (See *SPP Makes Moves Out of the Southwest*.)

The New York Times article that started a fresh round in this old debate spent a lot of time focusing on ballooning transmission and distribution bills that have little to do with markets.

Among the causes the *Times* cited for the higher prices in "deregulated" states are transmission and distribution costs and power company profits. "Deregulated states may spend more on transmission," R Street Institute energy adviser Josiah Neeley acknowledged in a *rebuttal* published in *Reason*. "But that part of the market is still heavily regulated."

Of the three big categories that feed into customers' bills — transmission, distribution and generation — transmission is the smallest of the three. By opening up new resources to serve load, it puts downward pressure on prices, said Cavanagh.

"The entire country is now linked by high voltage interstate transmission, which is regulated on the provision of non-discriminatory access," he added. "That's the American model. We're not divided on that; we're divided on lots of other things, but not that."

Transmission and distribution spending will need to increase to ensure the industry can reliably and affordably transition to the kind of cleaner grid needed to avoid the worst impacts of climate change.

"The impact of broader transmission is to create lower wholesale power prices, which is the whole point," Wood said. "You want to have broader markets to get access to the most cost-effective power, which is a bigger percentage of the customer's bill than the wires charges are."

Texas saw the benefits of expanding transmission with its Competitive Renewable Energy Zone lines, which were planned 15 years ago and came with a $7 billion price tag to bring wind from the resource-rich areas of the state to its cities. They wound up producing benefits that were five times their cost, Wood said.

The distribution system is going to need investment as well, to ensure that it can handle all the new sources of demand, such as plug-in vehicles and heat pumps, as well the growing distributed resources such as solar panels and batteries, he added.

Do Markets Help with Greening the Grid?

Alison Silverstein, Silverstein Consulting | *© RTO Insider LLC*

Silverstein argued that beyond transmission, wholesale competition has helped to weed out old, inefficient coal plants and replaced them with cleaner, more efficient natural gas — and in more recent years, renewable power.

"God forbid, thinking about what we might have had for the rate of climate change and extreme weather if we hadn't been enabling competition to shut out older and natural gas plants that were emitting even more carbon and were highly inefficient," she said.

While most experts support the idea that transmitting renewables around a large, centrally managed grid helps, some questioned whether the competitive markets were really helping renewables. Public Citizen's Slocum argued that the shift to renewables has put the system under strain, as seen with efforts from FERC under the Trump administration to block their impact on the market through the minimum offer price rule.

"Renewables are coming into the system in spite of the market design," Slocum said. "They're coming into the system because of regulatory mandates and financial incentives, which are not the markets. And as a result, it's upending the market-based pricing system." ■

FERC/Federal News

A 'Deregulation' Debate by the Numbers

Continued from page 3

ulation" with organized RTO/ISO wholesale markets.

While 13 states and the District of Columbia allow most of their electric customers to choose their electric supplier, the *Times* appeared to be including as "deregulated" 21 states whose utilities participate in organized wholesale markets but do not allow retail choice, said R Street Institute energy adviser Josiah Neeley in a *rebuttal* published in *Reason*.

The *Times* "seems to say that the label 'deregulation' applies even in places like Minnesota, where no customer exercises a choice in provider, and where the industry simply has been restructured to be part of a larger grid with two different regulators (FERC and the state)," tweeted former Montana regulator Travis Kavulla.

Kavulla, now vice president of regulatory affairs for NRG Energy (NYSE:NRG) also rejected the characterization of California as "deregulated," saying it "stands as the foremost example of a jurisdiction where policymakers treat utility balance sheets as playthings for various policy ends.

"There is no such thing as 'deregulation' or a 'free market' in this industry anywhere — which remains regulated everywhere," Kavulla added.

A power and gas trader who tweets under the name "King of Power" called the piece a "master class in how not to do power market analysis," adding that "the article is so full of bad methodology and blatant falsehoods that it would make a utility blush."

Other critics pointed to a lack of supporting data in the piece.

McCullough, who was prominently quoted by *Times* reporter Ivan Penn, also produced the data that was cited in the article but conspicuously absent from it. In an interview with *RTO Insider*, McCullough acknowledged that omission, but said he thought the piece was "generally a good article" that just required more "column inches" to do the subject justice. He said he may have "overwhelmed" Penn "on this whole question of competition."

"Of course, one of the evocative things about electricity — evocative in that it attracts a lot of confusion — is it is complicated, and so it's very hard to get some of the concepts across,"

Robert McCullough | © *RTO Insider LLC*

McCullough said.

Penn did not respond to a request for comment.

Some of that confusion may have stemmed from the article's use of the term "deregulated." In our interview, McCullough said the analysis he provided the *Times* wasn't really a comparison of retail electricity prices in deregulated versus regulated states, but between states operating inside and outside of organized markets.

McCullough's staff sourced the price and volume data from the U.S. Energy Information Administration's Electric Power Monthly reports, and calculated weighted price averages to show differentials between RTO and non-RTO states.

"Is that exact? No, because of course, some of the states are split between two [markets]. But was it honest? Yeah — it's a pretty straightforward calculation," McCullough said.

The data does not control for differences in fuel costs or resources across regions, because, McCullough said, the *Times* only requested retail price numbers. A spreadsheet he provided to *RTO Insider* includes a retail price data series covering January 1998 to October 2022, showing average monthly prices and total electricity consumption by state. That data is then distilled into a comparison of prices between RTO and non-RTO states over the entire period.

The first entry, January 1998, before widespread implementation of retail choice, shows an average retail price of 6.33 cents/kWh in non-RTO states and 7.41 cents/kWh for states that would eventually join RTO states. During the Western energy crisis in 2001, the spread increased sharply, with non-RTO states averaging of 6.47 cents/kWh and RTO states 9.35 cents/kWh.

During a period of relatively high natural gas prices from 2002 to 2009, retail prices averaged 8.35 cents/kWh in non-RTO states versus 9.99 cents/kWh in RTOs. In the 2012-15 period of lower gas prices, average non-RTO and RTO state prices were 9.52 and 10.47 cents/kWh, respectively.

A graph included with the data illustrates trends across the time series, with callouts for events in which RTO price spikes outpaced those in non-RTO areas. The events include the commodities price bubble of 2008, the ERCOT outages accompanying February 2021's winter storm and Russia's invasion of Ukraine in February 2022.

McCullough contends that prices in RTO areas can be more sensitive to such events because RTOs rely on the single market clearing price mechanism to set prices, as opposed to the "price-as-bid" nature of the traditional utility model.

"For states served at the market clearing price — ERCOT comes to mind — the swings are greater because the entire market is priced at the market clearing price," he said. "And, of course, for ERCOT the reserve margin price adjustment, as well as the ERCOT-administered emergency price cap, creates quite a 'bump.' A peculiarity of the ERCOT rolling outages is that the prices crossed the ERCOT border and extended all the way north to North Dakota in the SPP market. This is somewhat peculiar given the limited transmission, but [it] did affect retail rates."

McCullough was among the first industry watchers to identify the manipulation that sparked the Western energy crisis of 2000-01, when energy traders such as Enron exploited adverse market conditions and design flaws in California's organized electricity market to drive up wholesale prices. Their actions caused rolling blackouts, bankrupted Pacific Gas & Electric and nearly sunk Southern California Edison. He has long been a vocal critic of RTOs and ISOs, which he refers to as "administered" markets, compared with what he calls the "competitive" bilateral wholesale markets that still predominate in most of the West.

"Northwest power markets are large and

FERC/Federal News

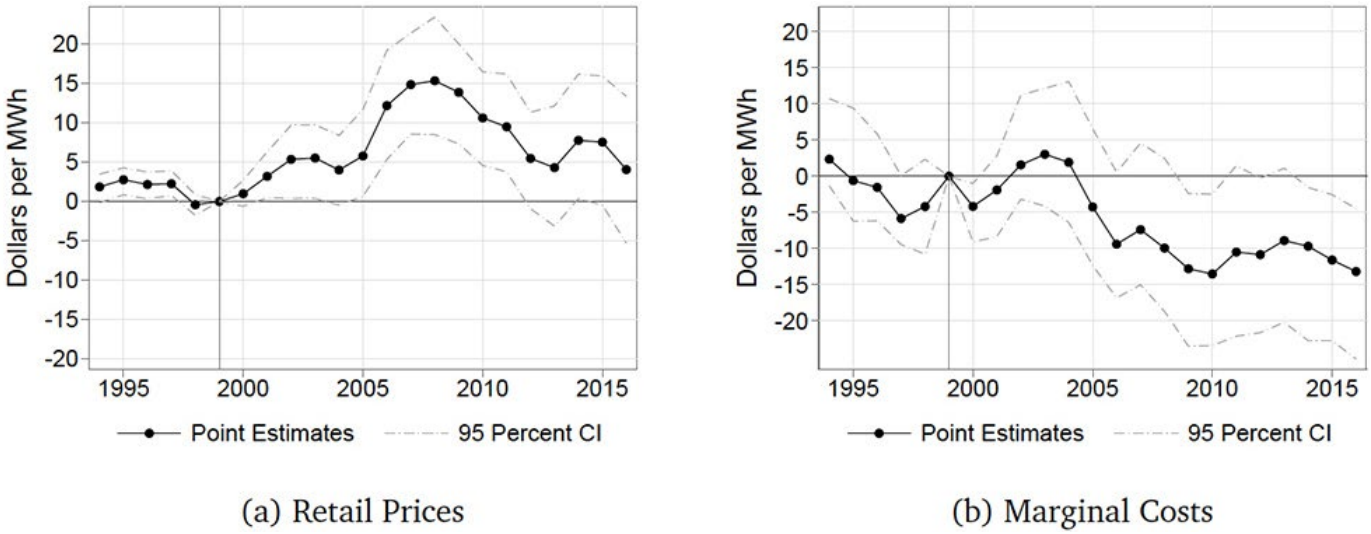


Figure displays difference-in-differences matching estimates of changes in (a) retail prices and (b) fuel costs for deregulated utilities. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to 1999, which is the year prior to the first substantial deregulation measures. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling. | *Alexander MacKay and Ignacia Mercadal*

competitive and low-price**,** but we don't have a central administrator to tell us what to do. How valuable is the central administrator on energy markets and prescheduled energy markets? I suspect the answer is**:** pretty irrelevant," he said.

McCullough thinks the Northwest has "maintained a very successful, large, efficient market for many years … with very few abuses, no blackouts, [and] guys who actually call each other on the phone and buy and sell**.**

"Exceedingly transparent. Far more transparent than in the California ISO because you know everyone's prices every day," he said.

Impact of Markups

R Street's Neeley also challenged the *Times'* contention that competition leads to higher prices because of "profits taken in by energy suppliers."

"Based on reading the *Times* article, you might be surprised to learn that monopoly utilities also make profits," Neeley wrote. "Indeed, utility rates are typically set to give the utility a set percentage of profit based on their past investments. This, needless to say, does not encourage utilities to find ways to lower costs."

The *Times* article might have strengthened its thesis if it gave more than passing mention to a Harvard *working paper* published last month that does in fact focus on the impact of electricity deregulation on ratepayers.

The authors of the paper, Alexander MacKay, assistant professor of business administration at Harvard Business School, and Ignacia Mercadal, assistant professor of economics at University of Florida, say their work seeks to fill a gap in the academic discussion on electricity restructuring by addressing the question of whether deregulation of wholesale (as opposed to retail) markets has resulted in lower electricity prices for end consumers.

Their findings suggest the opposite: that consumers in markets subject to wholesale deregulation have seen greater increases in retail prices compared with those in fully regulated environments.

"Based on reading the Times article, you might be surprised to learn that monopoly utilities also make profits."

— Josiah Neeley, R Street Institute energy adviser

"The goal of our analysis is to evaluate the effect of electricity restructuring on markups and prices. For this, we compare utilities in restructured states to those that remained vertically integrated and regulated, and we examine the evolution of costs, wholesale prices, and retail prices over time," MacKay and Mercadal explain in the paper.

While the study does not specifically focus on differentials based on RTO markets, it does address the influence of those markets on price outcomes, in part because nearly every retail choice state featured in the study — except Oregon — participates in an RTO or ISO. That study also relies on EIA retail price data sets.

The study examines the period between 1994 and 2016, using 1999 as the "baseline" for retail prices and relying on a "difference-in-differences" approach that measures the price movements in deregulated states relative to the those in the "control" group of states that did not implement retail choice. It finds that states that unbundled their monopoly utilities started with a higher baseline for retail prices (averaging $79/MWh — or 7.9 cents/kWh) than those in the control group ($59/MWh), which is attributed to higher fuel prices in the deregulated states at the time.

From 1994 to 1997, the analysis showed prices were stable for both groups, followed by a convergence over 1998-2000 as prices in deregulated states declined while those in control states held steady. "Starting in 2001, prices in both states began to rise. Deregulated prices outpaced control prices until 2005, when the gap between the two widened further," the authors write.

FERC/Federal News

From 2000 to 2005, deregulated utilities saw average price increases of $3.90/MWh, followed by a sharper rise of $12.60/MWh from 2006 to 2016 (a 16% increase from the baseline), for an average increase of $7.60/MWh over 2000-2016.

"We reiterate that these changes are difference-in-differences effects, i.e., increases above and beyond the price trends occurring in control utilities," the authors wrote.

Another key finding: while retail prices rose in deregulated markets, generation costs declined, with average fuel prices falling by $6.90/MWh over the study period. The authors say that indicates generators were earning higher "markups" for their power — the difference between the selling price for power and the cost for generating it. The study finds that markups were "modest" from 2000 to 2005, but spiked to $20/MWh over 2006-2011 (See graph).

MacKay and Mercadal attribute that development to a combination of factors present in deregulated markets, including an increased concentration of power suppliers and a larger pool of buyers that now includes utilities, power marketers and industrial customers. They contend that when the wholesale price caps that states implemented to smooth the transition to deregulation began to expire around 2005, bargaining power for distribution utilities declined while the market power of generators increased.

"For a utility, obtaining electricity from the wholesale market was more expensive than [providing its own generation], as wholesale prices reflect a markup. … With deregulation, utilities effectively paid a market-based markup to generation facilities that they had previously owned."

— Alexander MacKay, assistant professor of business administration at Harvard Business School, and Ignacia Mercadal, assistant professor of economics at University of Florida

"For a utility, obtaining electricity from the wholesale market was more expensive than [providing its own generation], as wholesale prices reflect a markup. … With deregulation, utilities effectively paid a market-based markup to generation facilities that they had previously owned," they say.

At the same time, incumbent utilities increased their regulated retail rates to reimburse average variable costs, which "went up due to the introduction of this markup."

The study also contends that the specific characteristics of electricity make wholesale markets "particularly prone to market power."

"Both demand and supply are inelastic, yet supply must meet demand at every moment since large amounts of electricity cannot be stored efficiently. Transportation is expensive, constraining the degree to which generators compete across local markets. Entry is limited due to large sunk investments, long planning horizons, and high risk. As a result of these factors, only a few generators are typically competing to serve demand for a certain area at a particular moment, and the relative scarcity can give them substantial market power. Deregulation did not fundamentally change these factors," the authors say.

Tyson Slocum, director of Public Citizen's energy program, said the Harvard study indicates that the efficiency gains from wholesale markets "are all being vacuumed up by these sophisticated traders and other market participants" who exploit arbitrages and take the profits, leaving no savings to end consumers.

"It's a who's who of sophisticated financial traders," Slocum said. "Those guys are parked in those markets, not because, you know, 'Gosh, we need to work every day to deliver value to end users.' They're like: 'We're going to be heavily in these markets to exploit the arbitrage and make enormous and unregulated profits.' That's what's driving RTO activity."

"It's a who's who of sophisticated financial traders. Those guys are parked in those markets, not because, you know, 'Gosh, we need to work every day to deliver value to end users.'"

— Tyson Slocom, Public Citizen

'Likely Wrong'

But criticism of the study came from a different corner, setting off an exchange that illustrates the difficulty of reaching consensus on the impacts of electric restructuring.

Scott Harvey, an energy consultant with FTI Consulting and member of CAISO's Market Surveillance Committee, picked apart the paper in an email to *RTO Insider*. Among other complaints, Harvey contended that its finding of declining fuel costs for generators from 2002 to 2015 was "incomprehensible" and that there must be something "fundamentally flawed" in how those costs were measured.

He also argued that the wholesale electricity prices used in the paper do not reflect prices in the spot markets, but the higher prices since 1994 for various types of contracts, including those for securing renewables to meet state environmental mandates.

"Hence the fuel cost measure is wrong and the wholesale price measure is wrong. All of the results in the paper are likely wrong," Harvey wrote.

MacKay and Mercadal defended their approach for measuring fuel costs and noted that their analysis checked for variables such as environmental regulations.

Mercadal also said it would've been incorrect to just focus on spot prices in their analysis.

"A big point of our paper is that most of the purchased electricity (>80%) comes from contracts (not spot markets), and these prices are indeed often higher. We can't just ignore these prices … they really do matter for the prices that consumers pay!" she wrote.

"We would be happy to see evidence supporting other explanations for our findings. We tried competing hypotheses but were not supported by the data," Mercadal said. ■

FERC/Federal News

CEQ Raises Bar on GHG Analysis in NEPA Reviews

Guidelines Could Boost Renewables and Open New Path for Enviro Litigation

By K Kaufmann

The White House Council on Environmental Quality last week released updated *guidelines* for federal agencies performing environmental reviews, requiring them to include a detailed quantification of a project's greenhouse gas emissions, the estimated social costs of those emissions, and their impacts on climate change and community resilience.

Environmental assessments required under the National Environmental Policy Act should quantify a project's "GHG emissions; place GHG emissions in appropriate context and disclose relevant GHG emissions and relevant climate impacts; and identify alternatives and mitigation measures to avoid or reduce GHG emissions," CEQ said in the new guidelines published in the *Federal Register* on Jan. 9.

The issuance started a 60-day comment period, but the guidelines will go into effect immediately on an "interim" basis, CEQ said. Potential revisions may be made before they are finalized.

According to a *2020 review* by CEQ, NEPA environmental reviews can take anywhere from two to more than six years, making them a major factor in the long permitting times for large energy projects on public land in the U.S., be they utility-scale solar, natural gas pipelines or interstate transmission.

The new guidelines lay out detailed recommendations for NEPA reviews, for example, saying quantification of a project's GHG emissions should include both separate analyses of carbon dioxide, methane and nitrogen oxide emissions, as well as an aggregated total, factoring in "each pollutant's global warming potential."

"Where feasible, agencies should also present annual GHG emission increases and reductions,'" the guidelines say. "This is particularly important where a proposed action presents both reasonably foreseeable GHG emissions increases and reductions."

They also say that "the relative minor and short-term GHG emissions associated with construction of certain renewable energy projects, such as utility-scale solar and offshore wind, should not warrant a detailed analysis of lifetime GHG emissions."

Clean energy alternatives to fossil fuel projects also get a boost in the guidelines, which frame them as "in line with the urgency of the climate crisis," as well as U.S. national and global climate commitments. While noting that neither NEPA nor CEQ require agencies to go with a project with the lowest net GHG emissions, the guidelines say, "agencies should evaluate reasonable alternatives that may have lower GHG emissions, which could include technically and economically feasible clean energy alternatives."

CEQ Chair Brenda Mallory | *The White House*

These provisions, contained in a few sentences in the 14 pages that the guidelines take up in the *Federal Register*, received immediate support from clean energy trade groups.

"The interim guidance will enable clean energy developers to move forward with projects, particularly on federal lands, that not only reduce climate impacts from the power sector, but that also create jobs and add economic benefits for communities in areas where solar projects are sited," said Abigail Ross Hopper, president and CEO of the Solar Energy Industries Association.

The American Clean Power Association also issued a positive review. "The guidance appropriately recognizes that agency resources and time should not be spent reviewing the relatively minor and short-term greenhouse gas emissions associated with construction of clean energy projects and infrastructure that will provide large net emissions reductions over the course of their life."

'Should,' not 'Shall'

Industry analysts ClearView Energy Partners see the guidelines as evidence of a White House "lean into greening" strategies. But, ClearView says, the guidelines also set a *de facto* bottom line of zero GHG emissions as the minimum "significance level for purposes of triggering review under NEPA."

"The lack of a specific significance level also eliminates a bright line below which a project can be deemed to be 'not significant' for purposes of NEPA," ClearView said in its analysis of the guidelines.

ClearView also points to the guidelines' warning that "NEPA requires more than a statement that emissions from a proposed [project] or its alternatives represent only a small fraction of global or domestic emissions."

The intent of the guidelines is to treat all federal projects the same, ClearView says. "The CEQ makes clear that all projects must quantify direct emissions, and that only projects with 'small' GHG emissions may be able to use less detailed analysis of lifetime emissions due to overall negative carbon emissions of the project."

Further, the guidelines could nudge FERC and other agencies toward more in-depth analysis and quantification of GHG emissions. ClearView references FERC's practice of not evaluating a project's upstream or downstream emissions, arguing that it lacks jurisdiction to request such information from a project

FERC/Federal News

applicant. Rather, the guidelines say agencies should "seek to obtain the information needed to quantify GHG emissions" by requesting or requiring it from project applicants.

Here, ClearView sees an opening for the kind of litigation that can delay or derail a project.

"We think the interim guidance creates a significant, and potentially insurmountable, obstacle to agencies relying on a 'don't ask' strategy to limit the scope of GHG reviews in the future," ClearView says. "Now project opponents have strong grounds for appeals if they challenge an agency to make such inquiries in order to make upstream (or downstream emissions) estimates and the agency fails to do so."

ClearView expects plenty of opposition to the guidelines from the fossil fuel industry and congressional Republicans, who may argue that CEQ has gone "well beyond the statutory requirements of NEPA."

But, ClearView says, CEQ avoided using the word "shall," which signals hard and fast obligations, and instead provided agencies and itself cover by "strongly recommending" the guidelines "should" be followed.

CEQ also stakes out its interpretation of NEPA's jurisdiction on GHG emissions in the introduction to the guidelines. "Climate change is a fundamental environmental issue, and its effects on the human environment fall squarely in NEPA's purview."

Permitting Reform Preview

On the same day the CEQ guidelines were published, Rep. Pete Stauber (R-Minn.) introduced a *bill* that would cut NEPA review for mining projects to 12 months for an environmental assessment and 24 months for an environmental impact statement. The bill would also require that appeals against a permit be filed within 120 days of a project approval.

Under NEPA, an environmental assessment is an initial study to determine whether a project will have significant impacts requiring a full review and environmental impact statement.

Some of the other key recommendations in the CEQ guidelines include that:

- agencies should "leverage early planning processes" to incorporate GHG emissions quantification and analysis of climate impacts and options for mitigation from the very beginning of environmental reviews;
- such early planning should also include consideration of impacts on and active engagement with low-income, minority and other environmental justice communities;
- along with the quantification of GHG emissions, agencies should perform an analysis of the social cost of emissions, as opposed to a comprehensive cost-benefit analysis;
- the impacts of climate change — such as extreme weather, drought and wildfires — on a project over time should also be factored into the environmental review; and
- quantification of a project's GHG emissions should also be "contextualized" in terms of impacts on international, national, state and local climate goals.

ClearView sees this last provision as "bringing global dynamics home in requiring federal agencies to discuss the impacts of a project with a large GHG footprint in context of international commitments and federal policy. It could allow for agencies to determine that a project's GHG emissions [are] contrary to emission targets or goals established." ■

National/Federal news from our other channels

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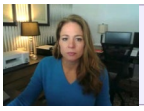


NERC Standards Process Changes Headed for Public Comment — ERO Insider

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

FERC/Federal News

DOI's Klein Picked to Run Bureau of Ocean Energy Management

By James Downing

The U.S. Department of the Interior announced last week that Elizabeth Klein has been named director of the Bureau of Ocean Energy Management, which oversees offshore energy and mineral resources.

She will replace Amanda Lefton, who has run BOEM since the start of the Biden administration and is resigning effective this Thursday.

Under Lefton, BOEM approved the country's first two commercial-scale offshore wind projects and has held three offshore wind lease auctions. The three lease auctions included a record-breaking sale off New York and the first-ever sale off the West Coast.

"Liz has been an invaluable asset at the department since Day 1, and we are thrilled she is taking on this new role," Interior Chief of Staff Rachael Taylor said. "The Interior Department is leading the effort to foster a clean energy future, and Liz will be critical to our efforts to meet the president's ambitious goals to deploy affordable clean energy to power homes across America and create good-paying jobs in the growing offshore wind industry."

Klein, who currently serves as senior adviser to Interior Secretary Deb Haaland, was previously nominated for deputy secretary of the department, but that was withdrawn early in President Biden's term after opposition from Sen. Lisa Murkowski (R-Alaska).

This is Klein's third stint at DOI, having worked at the department during the Clinton and Obama administrations. Before joining the Biden administration, she was deputy director of the New York University School of Law's State Energy & Environmental Impact Center, which supports state attorneys general when they defend, enforce and promote laws and policies on clean energy and the environment.

Klein was a key architect of the Obama administration's work to create a new offshore wind industry and leasing program.

The American Clean Power Association thanked Lefton for helping lay the foundation to get to 30 GW of offshore wind by 2030 and welcomed BOEM's new boss.

"We also are excited to work with Elizabeth Klein, who brings a wealth of experience to BOEM, having worked in the highest levels of

Liz Klein | *U.S. Department of the Interior*

the Department of the Interior under Presidents Obama and Biden," ACP Vice President for Offshore Wind Josh Kaplowitz said. "The offshore wind industry looks forward to ongoing collaboration with incoming Director Klein and her team to accelerate offshore wind energy development and deployment, while creating jobs for American workers and investing in American communities." ■

Southeast

Vogtle 3 Activation Delayed Again for Safety Concerns

Vibrations Discovered During Start-up of New Reactor

By Holden Mann

Southern Co. said Wednesday that Unit 3 at Vogtle nuclear plant in Waynesboro, Ga., has suffered yet another delay and is now not expected to come online until at least the second quarter of 2023, rather than the first quarter as previously predicted.

The utility disclosed the change in plans in a *filing* with the Securities and Exchange Commission.

According to the filing, Southern Nuclear was in the process of start-up and pre-operational testing for Unit 3 when it detected "vibrations associated with certain piping within the cooling system," which it is currently "in the process of remediating."

Details of the vibrations were not provided in the filing. Southern said it plans to file a license amendment request with the Nuclear Regulatory Commission in hopes of speeding up the remediation process, but that initial criticality will not occur until February, and Unit 3 will not enter service until April.

Jacob Hawkins, a spokesperson for Georgia Power, said in an email to *RTO Insider* that the utility's remediation plans include "strengthening the support for the pipes," which must be done before progressing to initial criticality. Hawkins said Georgia Power is "focused on getting this project done right, with safety and quality first."

The delay is expected to raise base capital costs for Georgia Power, the operator of the plant, by up to $15 million per month, not including additional costs for construction, support resources, or testing. Southern said it will share additional updates during its earnings call in February and warned of "ongoing or future challenges," including management of contracts and vendors, and subcontractor performance.

Vogtle Unit 3 has been under construction since 2009, along with Unit 4; Units 1 and 2 at the site have been in operation since 1987 and 1989, respectively. They are the only reactors currently under construction in the U.S., and Southern is calling them "the first new nuclear units built in the United States in the last three decades." When units 3 and 4 come online, Vogtle will be the only four-unit nuclear facility in the country.

The new units were originally intended to be operational by 2017, but the project has undergone numerous delays that provided considerable fuel for its detractors. Additional criticism has attached to the plant's cost overruns; in its *semi-annual progress report* to the Georgia Public Service Commission in August, Georgia Power said total construction expenses up to that point were $8.2 billion, above the original approved cost of $7.3 billion, and the final cost would likely be more than $10.7 billion.

However, the project has its supporters as well; Nuclear Energy Institute CEO Maria Korsnick in 2021 praised management and staff at Southern for pressing on, "undeterred by a global pandemic [and] getting the job done." (See *Nuclear Key to Clean Energy Future, NEI Says*.)

Georgia Power *announced* in October that it had begun loading fuel into Unit 3's reactor core following the receipt of a 103(g) filing from the NRC in August, indicating that "the new unit has been constructed and will be operated in conformance with the combined license and NRC regulations." Unit 4 completed cold hydro testing in December, the utility *said*, leaving hot functional testing, scheduled to begin this quarter, as the last major test remaining for the reactor. ■

Vogtle Units 3 and 4 cooling towers nearing completion in November. | *Georgia Power*

CAISO/West News

CAISO Issues Report on Western Regionalization Studies

By Hudson Sangree

CAISO on Friday released a draft report on Western regionalization that is intended to restart talks on the ISO becoming an RTO and bolster a likely legislative effort this year to open its governance to residents of other states.

The *report* examined 41 regionalization studies in response to last year's Assembly Concurrence Resolution 188, by State Assemblyman Chris Holden (D), chair of the Assembly Appropriations Committee and a proponent of CAISO expansion. *ACR 188* asked the ISO and the state's eight other balancing authorities to report to the legislature on recent and relevant studies of regional market impacts by Feb. 28.

"It's time for California to revisit a broader regional market," Holden said in a message accompanying the bill, which passed unanimously in the State Senate and Assembly.

Prior attempts by Holden in 2017-2018 to allow CAISO to become an RTO failed, but circumstances in California and the West have changed significantly since then. (See *Plans Revive to Make CAISO a Western RTO*.)

"Expanding CAISO to become a multistate regional transmission organization is an option that ACR 188 calls out specifically," the report notes.

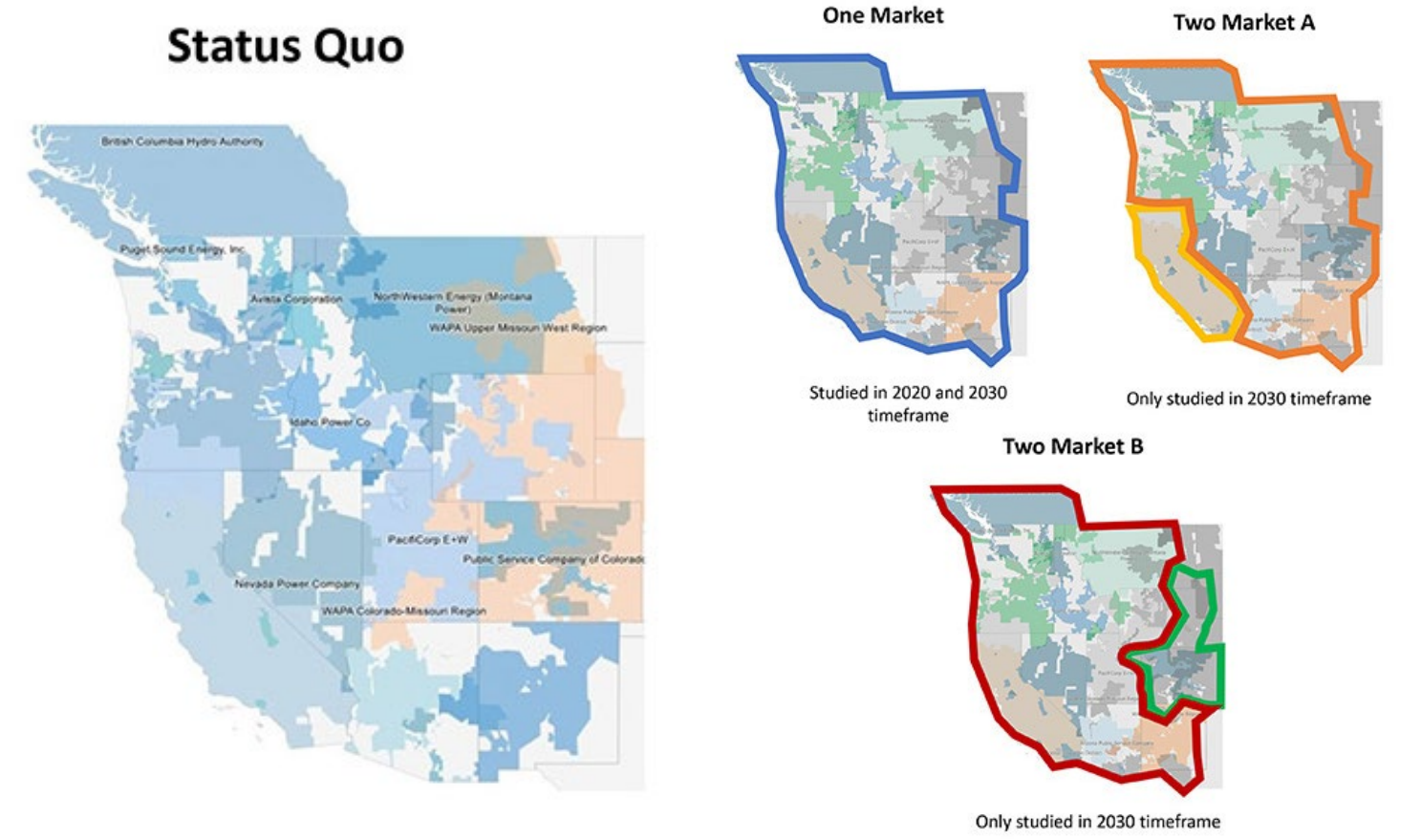
To avoid appearances of bias, CAISO commissioned the National Renewable Energy Laboratory (NREL) to write the report. "As a national laboratory of the U.S. Department of Energy, NREL is independent of any particular stakeholders and state policies," the report says.

NREL researchers examined dozens of studies that concluded California and most other Western states would benefit from increased collaboration in terms of cost savings, resource adequacy and meeting climate goals. They included a June 2021 study that found an RTO covering the entire U.S. portion of the Western Interconnection could save the region $2 billion in annual electricity costs by 2030 and cut carbon dioxide emissions by 191 million metric tons.

The study, funded by the U.S. Department of Energy, was led by Utah Gov. Spencer Cox's Office of Energy Development and energy offices in Colorado, Idaho and Montana. (See *Study Shows RTO Could Save West $2B Yearly by 2030*.)

A "large, multistate RTO is one of several options," the report says. "It could provide the largest margin of benefit, including the greatest visibility into operational performance, efficient dispatch and lower-cost reliability. Other forms of enhanced regional cooperation, such as a regional energy market, a regional mechanism for resource adequacy or even the expansion of an RTO to only a few neighboring states, would also provide some measure of cost savings, reliability improvements and reduced carbon emissions for the benefit of all participants."

However, "some of the technical studies included in this review suggest that the benefits of more comprehensive forms of regional cooperation might not be spread evenly across



A state-led study examined four potential market configurations for the West in 2030. | *Utah Office of Energy Development and S&P Global Market Intelligence*

CAISO/West News

participating states and their utilities," the report said. A section detailing the "distribution of benefits among states" in one or more Western RTOs is still being drafted.

"The CAISO is working with NREL to expand this section to be responsive to the legislation," the report says.

The state-led study found "that a single RTO would provide California and all other states greater capacity savings than two Western RTOs. For a day-ahead market, all states except Colorado would see greater capacity savings with one market rather than two."

A separate *study* conducted by the Colorado Public Utilities Commission at the behest of Colorado lawmakers determined that the state would benefit more if there were two RTOs: one led by CAISO, and another by SPP that includes most utilities in Colorado and some in Wyoming.

"This study found significant cost savings to Colorado if its utilities were to join a regional RTO," the report says. "Interestingly, the benefits were slightly greater for joining SPP: a 9% savings in total system costs over the status quo reference case, compared to 8% for a [WECC-wide] RTO and 7% splitting Colorado between SPP and a WECC RTO."

If Colorado participates in a WECC-wide RTO, "higher power prices in the West [especially California] lead to slightly higher prices in Colorado," it said. "The marginal cost of serving demand in Colorado under a WECC RTO was about 16% higher than it would be if Colorado utilities were in SPP. Colorado also retired more coal capacity under the SPP RTO."

In the past two years, a handful of Colorado utilities decided to join SPP's real-time Western Energy Imbalance Service instead of CAISO's larger Western Energy Imbalance Market, with some exploring membership in SPP's RTO. (See *Colorado Utilities Choose WEIS over WEIM*.)

The ACR 188 report comes as CAISO and SPP continue to vie for Western market share in a region primed for one or more organized electricity markets.

SPP plans to launch its Markets+ offering with many of the services of an RTO and later to introduce a Western version of its Eastern RTO called RTO West. CAISO intends to add a day-ahead market to its successful real-time WEIM, which could eventually develop into an RTO. The Western Power Pool (formerly the Northwest Power Pool) is seeking FERC approval for its Western Resource Adequacy Program, a possible RTO launchpad. And Colorado and Nevada have ordered transmission-owning utilities to join an RTO by 2030.

The retirement of coal generation and increase in wind and solar resources in remote parts of the West is a major factor driving the need for regional transmission planning, the report notes. Strained grid conditions during heat waves have shown the need for better a resource adequacy framework, and a growing number of states are adopting clean-energy goals, requiring more interstate transactions, it said.

CAISO has scheduled a stakeholder *call* for this Friday to discuss the report.

"The ISO values stakeholder input on this preliminary draft and plans to incorporate feedback received during the Jan. 20 stakeholder call, and in written comments submitted by the deadline on Feb. 3, into future iterations to ensure the accuracy and value of the final report," the ISO said last Friday in a message to stakeholders. ■

CAISO/West News

Newsom Proposes $6B in Climate Budget Cuts

By Hudson Sangree

Gov. Gavin Newsom presented his budget plan Jan. 10 via YouTube. | *California Governor's Office*

California Gov. Gavin Newsom last week presented his fiscal year 2023/24 budget plan, which proposes eliminating $6 billion in funding for clean transportation and other climate initiatives because of a projected plunge in tax revenue caused mostly by the declining value of technology stocks.

The cuts would reduce last year's $54 billion five-year commitment for climate initiatives to $48 billion, maintaining 89% of last year's historic funding levels. Even reduced, the amount represents the world's largest climate pledge at a "sub-national level," Newsom said.

California could still see billions of dollars from the federal Inflation Reduction Act (IRA), "not only filling that bucket back up but substantially increasing the total investment," and that's the reason why climate and transportation were targeted for some of the largest cuts in this year's budget, the governor said.

If financial conditions improve, the budget proposes a $3.9 billion "trigger" mechanism to restore much of the reduced spending in FY 2024/25, Newsom noted. A recession, however, could require even deeper budget cuts in the May revision of the budget plan, he said.

The governor's budget *summary* details the financial conditions that made it necessary to reduce overall state spending next fiscal year.

"As 2023 begins, risks to the state's economic and revenue outlook highlighted in the 2022 budget have been realized — continued high inflation, multiple federal reserve bank interest rate increases, and further stock market declines," it says. "This last risk is particularly important to California, as market-based compensation — including stock options and bonus payments — greatly influences the incomes of high-income Californians. Combined with a progressive income tax structure, this can have an outsized effect, both good and bad, on state revenues."

The state's revenue outlook is "substantially different than … in the last two years" of record surpluses, it notes. The governor's budget forecasts that state general-fund revenues will be $29.5 billion lower than in 2022/23.

"California now faces an estimated budget gap of $22.5 billion in the 2023-24 fiscal year," it says.

Bond sales or withdrawals from the state's budget reserves could offset further reductions, it says. In 2014 voters approved Proposition 2, requiring funding upgrades to the state's Budget Stabilization Account, known as the rainy day fund. To make withdrawals, the governor must declare a state of emergency.

The account now holds $22.4 billion and constitutes the largest portion of the state's $35.6 billion in total budget reserves, the budget proposal says.

Major cuts proposed in the governor's budget include a $1.1 billion reduction in the state's $10 billion, five-year commitment to funding for light-, medium- and heavy-duty zero-emission vehicles that was adopted in the past two fiscal years.

"The budget maintains $8.9 billion (89%) of ZEV investments with a focus on communities that are the most affected," the budget summary says. "This includes targeted investments in disadvantaged and low-income communities by increasing access to the benefits of clean transportation and by continuing to decarbonize California's transportation sector and improve public health."

In addition, it proposes $2.5 billion in "reductions across various ZEV programs, which are partially offset by approximately $1.4 billion in fund shifts to cap-and-trade funds.

"Further, the administration will pursue additional federal funding to help offset the decrease in state funds," it says. "For example, the federal IRA includes $100 billion to states for clean energy and climate investments. The administration will continue to aggressively pursue this federal funding."

Some proposed program cuts include:

- A reduction of $745 million in state general fund dollars for programs that "expand affordable and convenient ZEV infrastructure access in low-income neighborhoods." The cuts would be "partially offset by a shift of $535 million to the Greenhouse Gas Reduction Fund. This maintains approximately $2.1 billion (91%) for programs," according to the budget summary.
- A $1.5 billion general fund reduction for programs that support drayage trucks, transit buses and school buses, "which is partially offset by a shift of $839 million to the Greenhouse Gas Reduction Fund. This maintains approximately $5.3 billion (89%)" of the original funding," it says.
- A $270 million cut to the California Public Utilities Commission's residential solar and storage program. "This maintains approximately $630 million (70%) for solar and storage incentives for low-income utility customers," the budget summary says.
- A reduction of $50 million from the long-duration energy storage program at the California Energy Commission. "This maintains approximately $330 million (87%) for support of long duration energy storage projects that will help with the state's energy transition," it says. ■

CAISO/West News

FERC Approves PacifiCorp's Interconnection Replacement Rules

Clements Dissents over Competitive Concerns

By James Downing

FERC last week approved PacifiCorp's changes to its generator interconnection procedures that will allow it to use retiring generators' interconnection capacity for new power plants in a process overseen by an independent coordinator (*ER23-407*).

The commission has already approved similar rules for Dominion Energy South Carolina, Public Service Company of Colorado and Duke Energy's utilities in the South.

PacifiCorp argued that its new rules are superior to FERC's *pro forma* interconnection rules because they create efficiencies by using existing interconnection capacity of retiring facilities, cutting interconnection timelines and uncertainty for new plants that use the process. Using existing interconnection capacity means that no new lines will have to be built to reliably connect power plants.

The Western Power Trading Forum told FERC that the independent coordinator was needed to minimize possible anticompetitive impacts from PacifiCorp reusing its old plants' interconnection capacity, especially when the new generators use a different fuel.

TerraPower supported the rules, which it plans to use in the development of its Natrium nuclear reactor demonstration project at the site of PacifiCorp's coal-fired Naughton Power Plant, where the remaining two units are set to retire in 2025.

Lineworkers on a PacifiCorp transmission line | *PacifiCorp*

FERC conditionally accepted the rules, subject to PacifiCorp fixing a typographical error on one of its tariff sheets.

"We find that PacifiCorp's proposed generator replacement process provides substantial benefits and, in combination with the safeguards against unduly discriminatory implementation provided by the proposed independent coordinator, satisfies the consistent with or superior to standard with respect to the *pro forma*" large generator interconnection procedures, FERC said.

The generator replacement rules are similar to ones FERC has approved for other utilities in the past, and they should produce the same benefits, the commission said. They will create efficiencies by using existing interconnection facilities at retiring facilities; reduce interconnection timelines; save money for customers by decreasing new construction; and cut interconnection-related uncertainty in generation resource planning.

While PacifiCorp owns "a significant share" of the existing generation on its system, FERC said the replacement model would provide benefits, as it comes with the independent consultant's review.

The order drew a dissent from Commissioner Allison Clements, who said PacifiCorp failed to show that the proposal is consistent with or superior to FERC's *pro forma* interconnection rules.

"In particular, protesters make compelling arguments, not present in those previous generator replacement rights proceedings, highlighting the potential for anticompetitive outcomes under PacifiCorp's proposal," Clements said. "Based on the record before us, I cannot conclude that the benefits of this proposal outweigh the potential significant negative impacts on open access and competition in the PacifiCorp region."

The main question is whether PacifiCorp will be able to retain up to 5,000 MW of interconnection rights in perpetuity without any opportunity for new generation to gain access to it. Clements said that the D.C. Circuit Court of Appeals rejected similar rules for Xcel Energy because of concerns of their anticompetitive effects and potential for undue discrimination. ■

CAISO/West News

New NM Regulator Steps down over Qualifications

Governor Appoints Industry Veteran as Replacement

By Elaine Goodman

Less than two weeks after Gov. Michelle Lujan Grisham appointed new members to the New Mexico Public Regulation Commission, one member has resigned, and the governor has named a replacement.

Lujan Grisham on Jan. 10 appointed James Ellison, principal grid analyst for the Grid Modernization Group at Sandia National Laboratories, to the three-member PRC. The appointment follows the resignation of Brian Moore, who said he didn't meet the educational requirements for the job.

The PRC had been a five-member elected body since its formation in 1996 but transitioned on Jan. 1 to a three-member appointed panel. Lujan Grisham announced her appointments on Dec. 30. (See *NM Rings in New Year with Reconfigured Utility Commission*.)

The revamped PRC held its first meeting on Wednesday with only Commissioners Patrick O'Connell and Gabriel Aguilera participating because Ellison hadn't been sworn in. The two commissioners decided that O'Connell will serve as PRC chairman.

Another item on the agenda was choosing a commissioner to serve on the SPP Regional State Committee. Aguilera expressed interest in the role, saying regional markets are one of his areas of expertise. But the commissioners agreed to wait until the next PRC meeting, when Ellison is expected to participate, to choose a representative.

Aguilera said the decision is an important one.

"In terms of regional markets, a lot of them are being designed right now, as we speak," he said. "So, I do think that it is very important for us to be in those conversations to make sure that whatever solutions come out of those discussions represent a good outcome for New Mexicans."

While Ellison did not participate in Wednesday's meeting as a commissioner, he attended as a special guest and commented on the role of the PRC.

"The PRC is tasked with ensuring that the transition to renewables takes place, and that it takes place while preserving reliability and while ensuring that the cost of power be as low as reasonably possible," Ellison said. "It's certainly an honor to play a role in this transition."

Moore, the PRC appointee who resigned, served in the state House of Representatives from 2001 to 2008 representing eastern New Mexico. He submitted a resume to the PRC Nominating Committee saying that he majored in business finance with statistical analysis at the University of Denver, but he never graduated from the school, a spokesperson for the governor told the *Albuquerque Journal*.

Under New Mexico statutes, PRC members must have a bachelor's degree from an accredited institution of higher education and at least 10 years of experience in the energy sector or an area regulated by the commission.

Alternatively, the commissioner may have completed higher education resulting in a professional license or a post-graduate degree in a field related to an area regulated by the commission and have at least 10 years of experience.

A seven-member PRC Nominating Committee selected nine potential commissioners and sent their names to Lujan Grisham for consideration. The governor noted that the Nominating Committee vetted the candidates. ■

The New Mexico PRC's headquarters in Santa Fe. | *New Mexico Public Regulation Commission*

CAISO/West News

NV Energy Blames 'Heavy, Wet Snow' for New Year's Outages

By Elaine Goodman

Winter storms that dumped heavy, wet snow on Northern Nevada knocked out power to almost 124,000 NV Energy customers over the New Year's holiday weekend, according to a report from the utility.

The outages reached a peak around 8 p.m. on Dec. 31, when 89,378 customers were without power, NV Energy said in a report filed with the Public Utilities Commission of Nevada. And 8,000 customers still didn't have power on Jan. 3, according to PUCN.

NV Energy filed the report on Wednesday in response to an order from PUCN. The commission opened a docket on Jan. 3 to investigate the causes of the outages and the utility's response.

In its report, NV Energy said "extreme weather" caused the outages.

"The storm was a very long-duration, atmospheric river storm that affected the entire region of Northern Nevada with heavy precipitation in the form of heavy, wet snow," the report said.

Storm-related damage occurred across most western Nevada valleys and at Lake Tahoe, as tree branches snapped and snow piled up on power lines and equipment.

NV Energy dealt with 765 separate outages impacting an estimated 123,879 customers from Dec. 30 to Jan. 5. Twenty-nine of the outages were momentary, and the remainder were prolonged.

The outages mainly involved the distribution system and were caused by blown fuses, downed wires, broken poles, and damaged transformers and pole line hardware. In addition, downed wires and damaged structures caused some transmission-level outages, the utility said.

NV Energy worked to first address outages affecting the largest number of customers.

As power was restored to many customers, the focus shifted to customers who had been without power for the longest time.

On Jan. 4, NV Energy made direct calls to 614 residential customers who had been without power for more than 48 hours, offering free lodging at a local hotel and checking to see if they needed water for livestock.

The utility also communicated with customers through the news media, its website and social media.

NV Energy initially dispatched four of its own crews to repair the outages on Dec. 31. Additional crews were then brought in from other parts of the state, along with seven contract crews, for a total of 18 crews on Jan. 2. A typical crew consists of four or five linemen.

In addition to the crews, the response included troubleshooters, fire crews for snow and debris removal, and NV Energy's crisis and incident management teams. ■

Northern Nevada continued to dig out from a series of snowstorms that caused widespread power outages. | *© RTO Insider LLC*

ERCOT News

PUC Closes in on ERCOT's Market Redesign

Commissioners Trying for Consensus on Performance Credit Mechanism

By Tom Kleckner

AUSTIN, Texas — Texas regulators last week continued their deliberations of proposed ERCOT market redesigns, narrowing their focus to the favored performance credit mechanism.

To the disappointment of some, however, the Public Utility Commission did not take a vote on whether to recommend the market mechanism to lawmakers as its preferred design. The Texas Legislature opened its 88th session Jan. 10 and has been openly skeptical of the PCM, as it is known, and wants to see new dispatchable generation (i.e., thermal) added to the system. (See *ERCOT Survives One Test, Faces Another*.)

Michele Richmond, who leads a trade association representing ERCOT generators and wholesale marketers that supports the PCM, said she found the long day's discussion to be "very good," but still wanting.

"A decision is what gets movement on new investment. A recommendation to the legislature is not a decision. It's a recommendation," she told *RTO Insider* following the Jan. 12 meeting. "The commission should adopt a decision on [the market design]. And then, if the legislature wants to weigh in, if they want a new direction, then that's what should happen."

Following the 2021 deadly winter storm, lawmakers directed the PUC to establish a reliability standard to ensure operations during extreme heat and cold weather and when output is reduced from weather-dependent wind turbines and solar panels. The commission has promised to send its preferred market design to the legislature for its feedback, as PUC Chair Peter Lake reminded his fellow commissioners and those listening.

"If implemented. We still have to hear from the legislature," Lake said of one suggested market change. "Subject to consideration by the legislature," he said of another.

"Today's discussion was a deliberation, not making a decision on anything or recommending anything," Lake said in concluding the day's discussion.

The commissioners agreed to return to their open meeting room Thursday to continue their deliberations, with the goal of selecting a "policy direction" to fulfill their statutory obligation and ensure "reliability during periods of low non-dispatchable power." They will return on Jan. 26 to issue a final order.

ERCOT CEO Pablo Vegas (left) and board Vice Chair Bill Flores listen to the discussion. | © *RTO Insider LLC*

That would be just fine with Richmond. Her Texas Competitive Power Advocates (TCPA) organization *has said* its members are committed to adding 4.5 GW of additional thermal generation to the ERCOT system if the PCM is adopted under the "right framework."

TCPA members have banded together to create a *website* that points out it takes time and regulatory certainty to build new power plants. It includes a countdown clock that indicates a new power plant could come online as soon as April 25, 2025, assuming the PUC reaches a policy decision Thursday.

"I heard some pretty good consensus that something needs to be done," Richmond said. "I think the point that was made is that [the PCM] does get new investment."

The PCM, one of six alternatives studied by a San Francisco consulting firm, rewards generators for performance credits based on their performance during a determined number of scarcity hours. Those credits must be bought by load-serving entities based on their load during those same hours or exchanged by LSEs and generators in a voluntary forward market to hedge against negative outcomes in the retroactive settlement process. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

Katie Coleman, who represents Texas Industrial Energy Consumers, said the PCM is nothing more than a capacity market, anathema to many ERCOT stakeholders. Commissioner Will McAdams appear to wince as one speaker mentioned "capacity market" in his testimony.

"It's got all the problems a capacity market usually has," Coleman said of the PCM while preparing to return from a weekend getaway. "It's purely an administrative way for the government to order certain dollars to generators. The only difference with the PCM is that it's backward looking.

"It diverts dollars to generators. It's going to cost consumers billions of dollars," Coleman added. She said that given most reliability events are caused by operational issues such as unpredictable weather or outages, the PCM won't materially improve reliability.

The consultant's own *report* to the PUC argues the PCM would result in an extra $460 million in annual system expenses by 2026, about a

ERCOT News

2% increase over projected system costs. The firm, Energy and Environmental Economics (E3), did not recommend the mechanism, saying it was too complex. Instead, it put forth a forward reliability market as a "more suitable fit."

E3's Zach Ming, defending the firm's report, said that under the PCM, generators receive credits "by being available, not by being dispatched."

Stoic Energy's Doug Lewin, a dedicated follower of all things ERCOT, said the PCM's biggest problem is that it is "convoluted and extremely complicated."

"That makes it hard to finance," he *tweeted*. "Few investors, if any, will put money into long-term assets based on this. But existing generators will get a windfall."

State Sen. Charles Schwertner (R), who chairs the powerful Business and Commerce Committee, reiterated his committee's "serious concerns" with the PCM in a Jan. 11 letter to the PUC.

"Given … the clear absence of consensus among energy experts, advocates, and industry, unilaterally moving forward with a market design change such as the [PCM] option without consultation and collaboration with both the Texas House and Texas Senate is imprudent," he wrote.

The PCM does have its supporters in Texas Gov. Greg Abbott and ERCOT CEO Pablo Vegas. Abbott, who has appointed all five commissioners in the last two years, said in his own *filing* that the mechanism "must be given strong consideration."

"The fact that generators have already publicly committed to build thousands of new megawatts of dispatchable generation resources if

ERCOT stakeholders and PUC staff gather before the commission's Jan. 12 open meeting. | © *RTO Insider LLC*

PUC Commissioner Lori Cobos (right) listens to Chair Peter Lake. | © *RTO Insider LLC*

the PCM is adopted and implemented by the PUC further supports this point," he wrote.

Vegas said the mechanism "seems to offer the best combination of incentives that move our grid from a system characterized by extreme pricing, physical scarcity and conservation notices" by incenting generators to be available.

He said it will take staff as much as three and a half years to develop the PCM market system.

So, what will happen in the meantime? Vegas and the commission agree a bridge is needed for ERCOT to get by until the PCM is implemented. For the time being, that will consist of additional ancillary services and continued use of reliability unit commitments. RUCs have been in place since the summer of 2021 and raised concerns over the stress imposed on older generators.

The PUC raised the use of reliability must-run resource deployments, which haven't been issued since 2017. ERCOT ended NRG Energy's Greens Bayou Unit 5 RMR contract in 2017; the unit was retired shortly thereafter. (See "NRG to Retire 806 MW of Mothballed Resources," *ERCOT Briefs: Week Ending Dec. 11, 2017*.)

"I would strongly encourage this commission to avoid any type of policy path that relies on RMR in any way," NRG's Bill Barnes said. "An RMR contract means that you're putting new dollars into one of the oldest, most inefficient resources on our grid. It is literally one of the worst uses of capital."

"It concerns me that the only options we have are continued RUC and RMR," Commissioner Lori Cobos said.

Richmond said a phased-in PCM could be installed quicker than other proposed bridge mechanisms, pointing to *TCPA's comments*. She said that would signal the market when to self-commit, reducing the need for RUCs and "would provide economic incentives for existing dispatchable resources to remain in service."

"It has a number of components that exist in the market and are familiar to everybody, so it should be fairly easy to phase that in," she said.

ERCOT: December Storm 'Non-event'

ERCOT's Dan Woodfin, vice president of system operations, called the December winter storm a "non-event," despite the repeat of thermal outages and gas supply problems that were reminiscent of the 2021 winter storm.

He told the PUC that nearly 6 GW of coal and gas energy came offline after the cold weather swept through the state. Woodfin said global weather models predicted a significant cold weather event for Dec. 22, but the cold was "deeper and quicker" than the forecasts. ERCOT is reaching out to other grid operators who suffered similar under forecasts, he said.

Staff is also contacting generators that went offline to learn what happened. Woodfin said the weatherization requirements now in effect were effective in maintaining supply.

"We can see the grid we have now. The generators we have now are reliable. We just need more of them," Woodfin told the commission, promising a full report in several weeks.

The PUC also approved its *biennial report* to the Texas legislature. The report highlights the previous two years since the commission was reorganized after the 2021 winter storm, going from three members to five, and documents in actions in regulating the state's electric, telecommunications and water industries. ■

ISO-NE News

Hydro-Québec's Leadership Shakeup Could Impact New England

By Sam Mintz

Hydro-Québec's CEO stepped down last week, sending a shockwave through the Canadian energy sector that could reverberate into New England.

Sophie Brochu's resignation came amid tensions between the utility and the Québec government, which has pushed to "lure new power-hungry industrial users to the province," the *Montreal Gazette* reported on Jan. 10.

Brochu had been CEO of HQ since 2020 and had said as recently as October that she would stay on "as long as the company's governance framework remained 'healthy,'" the *Gazette* wrote.

The leadership upheaval comes as New England continues to heavily rely on imports from Québec to keep its own grid in good condition. HQ and its U.S. partners have also struggled to site the New England Clean Energy Connect transmission line, intended to bring down even more Canadian hydropower to the areas of heaviest electricity demand in southern New England.

In 2021, New England imported 16% of its electricity from neighbors, with most of that (13,617 out of a total 18,718 GWh in imports) coming from Québec.

Push and Pull

HQ spokesperson Lynn St-Laurent told *RTO Insider* that the company "has been a committed energy partner to New England for several decades and there isn't any reason at all to assume that this will change."

The company's strategic moves, however, have led some in the New England energy sector to wonder about the Canadian province's ability to continue sending its power to the Northeast U.S.

In its recent history, HQ has had a "pretty aggressive stance to maximize the revenue of exports," said Dan Dolan, president of the New England Power Generators Association.

And the Canadian utility recently looked to build its presence in New England by buying Great River Hydro and its fleet of 13 generating stations in the region.

But in a strategic plan led by Brochu last year, HQ warned that its energy and capacity balances are going to tighten over the next few years, and that the region will need new supplies by 2026.

"Electricity demand is … expected to rise, even though the rate at which the new needs will materialize is uncertain. As a result, we must prioritize the uses that stand to create the greatest value for Québec," the plan said.

How HQ responds to those needs is likely to have an impact on New England, said Dolan

"In a time of transition, it will be fascinating to see if there's a continuation of that [aggressive stance] or if we see a shift to taking a more inward look, because Québec for the last several years and during Christmas Eve, has had serious internal supply issues," Dolan said.

But St-Laurent noted that the strategic plan also calls for HQ to "increase our presence and operations in neighboring markets."

Leadership upheaval at Hydro-Québec could impact New England. | *Shutterstock*

Christmas Eve in the Spotlight

The events of Dec. 24 in New England are a clear example of the region's reliance on Québec.

One of the key triggers in the buildup to the Christmas Eve energy shortage was a sudden drop in imports from HQ.

It occurred as the Canadian province was dealing with a major storm and transmission outages, which forced it to reduce its exports to New England.

"In Québec, they were fighting both an actual load that was well above their forecast and the outages on their transmission lines. They were battling their own issues," said ISO-NE COO Vamsi Chadalavada at a recent NEPOOL meeting.

"The reduction of imports on Phase 2 over the day were because of what Québec was experiencing, but it did have a significant impact on us."

The loss of imports combined with generation outages in New England ultimately led the grid operator to go into its Operating Procedure 4 for the first time since 2018, and to subsequently dish out $39 million in pay-for-performance penalties to generators.

HQ says it upheld its contracted capacity sale obligations and helped maintain reliability in New England during the event.

"HQ maintained a reasonable level of export throughout the period despite the loss of transmission capacity in Québec," said St-Laurent. "In regards to its current capacity sale commitments in New England, HQ actually delivered more than what was committed during this period — 856 MW."

The reductions were due to HQ pulling back temporarily in the short-term spot market, she said.

But for NEPGA's Dolan, the event was another example of the precarious nature of bringing in electricity from other regions.

"They didn't pull back imports because they felt like it. They did it because they had a very high load show up on Christmas Eve," he said. "It's a provincially owned utility, and that's exactly what they should do. But it does create questions and consequences for us as an importing region."

St-Laurent said demand in Quebec on Dec. 24 was 31,510 MW, 9,000 MW short of its winter peak. ■

ISO-NE News

ISO-NE Outlines More of Plans for Capacity Accreditation, DA Ancillary Services

By Sam Mintz

ISO-NE is digging into the details on how it plans to measure the limitations of gas generators in its new capacity accreditation process.

At last week's NEPOOL Markets Committee meeting, the grid operator *continued laying out* its proposed methods for de-rating gas resources in the winter, when they may have challenges getting fuel.

Under ISO-NE's proposed framework, the capacity qualification process would include a determination of gas plants' firm and non-firm capacities for the December to February period each year. The RTO is developing firm fuel requirements that the generators would have to meet in order to get a firm capacity rating.

And there would be a new way to rate what ISO-NE is calling "operationally limited resources," which are those that are expected to be unable to get gas at all and would in turn be assigned zero qualified capacity for the winter period.

"Operationally limited resources are unlikely to receive gas on many cold days, let alone days when minimal non-firm gas is available for generators," *said* Alexander Mattfolk, a consultant with Levitan & Associates, which is helping ISO-NE develop the new framework.

These decisions will be backed by *new pipeline and LNG forecasts*, which Levitan is also helping to develop.

Other MC Business

Also at the MC meeting last week, ISO-NE *continued its explanation* of its proposed day-ahead ancillary services market, which is intended to fill energy gaps in the day-ahead market and procure reserves that can start up quickly, in 10 or 30 minutes.

Salem Harbor Power Station, a gas-fired generating plant in Salem, Mass. | *Fletcher, CC BY-SA 4.0, via Wikimedia Commons*

The project borrows heavily from ISO-NE's previous Energy Security Improvements project, which ultimately failed at FERC.

In addition to reiterating the basics of the market, which includes a new constraint called the forecast energy requirement and a new product called the energy imbalance reserve, ISO-NE shared its plan for forecasting real-time LMPs.

The grid operator is planning to use a "Gaussian Mixture Model," into which it will plug the day-ahead market load forecast, 24-hour lagged LMPs, the prices of gas and oil, weather forecasts and historical LMP data.

ISO-NE also continued its *discussion of updates* to the Inventoried Energy Program. ■

MISO News

Illinois, Public Citizen Ask for Confidential Docs in Dynegy Probe

The Illinois attorney general's office and Public Citizen are calling on FERC to release private files pertaining to the commission's investigation of Dynegy's conduct during MISO's 2015 capacity auction.

The organizations lodged a motion Jan. 6 asking FERC to direct its Office of Enforcement to allow access to "all documents and materials in its possession collected by enforcement staff during the non-public investigation of Dynegy" (*EL15-71*).

The Office of Enforcement concluded in a heavily redacted report last September that Dynegy engaged in market manipulation to ensure it could set prices in MISO's 2015/16 Planning Resource Auction. The finding reversed a three-year, non-public FERC investigation that cleared Dynegy of wrongdoing before ending abruptly in 2019. (See *FERC Staff Finds Dynegy Manipulated 2015 MISO Capacity Auction*.)

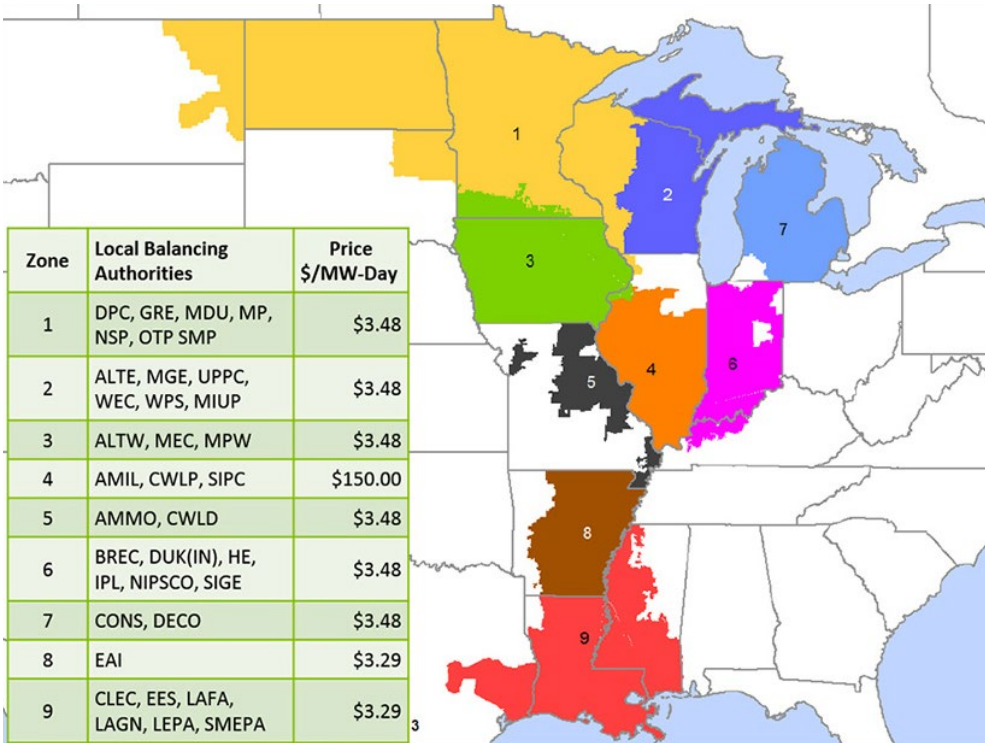
Illinois and Public Citizen said they're seeking documents that Dynegy or others provided to FERC enforcement staff during the investigation that they weren't privy to. They said they anticipate documents and depositions "that will likely be relevant to the issues" raised in their complaints.

The organizations have requested $428.6 million and interest from June 2015 to refund Illinois load serving entities' customers in MISO's Zone 4.

They said they have executed nondisclosure agreements to receive non-public filings from Dynegy about the refunds' status. They also said they've already committed to safeguarding information when they were granted access to the case's confidential remand report and appendix documents.

"The People and Public Citizen have already agreed to protect investigation materials in accordance with the commission's model protective order and should be granted the ability to review any and all materials in the possession of, or acquired by, enforcement staff," they wrote. ■

— Amanda Durish Cook



Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$3.48
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$3.48
3	ALTW, MEC, MPW	$3.48
4	AMIL, CWLP, SIPC	$150.00
5	AMMO, CWLD	$3.48
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE	$3.48
7	CONS, DECO	$3.48
8	EAI	$3.29
9	CLEC, EES, LAFA, LAGN, LEPA, SMEPA	$3.29

2015/16 MISO PRA results | *MISO*

MISO's Bear to Lead ISO/RTO Council, GO15 in 2023

By Amanda Durish Cook

MISO CEO John Bear will helm two international energy industry associations this year, the grid operator said Thursday.

The RTO said that Bear was appointed chair of the *ISO/RTO Council (IRC)* and also elected president of *GO15*, an international association of 15 grid operators that collectively manage more than half the world's electricity demand.

Bear succeeds Stefano Donnarumma, CEO of Terna, Italy's national transmission service operator, at GO15 and CAISO CEO Elliot Mainzer at IRC. The council includes representatives from the seven U.S. and two Canadian system operators. The IRC chair's role rotates annually among current IRC Board members.

MISO CEO John Bear | © *RTO Insider LLC*

"There is a need for continued collaboration and idea sharing when it comes to operating the power grid and planning for the future," Bear said in a *press release*. "Our collective problem solving enables us to keep the power flowing reliably and efficiently. That's true whether we are working locally, regionally, nationally or even globally."

Bear said he will focus on "major strategic and technical issues" affecting power systems during his GO15 term, including grid decarbonization and digitalization and the resilience of electricity infrastructure. ■

— Amanda Durish Cook

MISO News

Stakeholders Ask MISO for 2nd Look at Michigan Expedited Project

By Amanda Durish Cook

Stakeholders last week requested MISO take a second look at its recommendation for expedited transmission projects in Michigan.

During a series of technical study task force meetings, the RTO said it would recommend five expedited projects in its 2023 Transmission Expansion Plan (MTEP23). However, stakeholders said a $63 million package of a proposed substation and line work in Michigan could use more evaluation.

ITC subsidiary Michigan Electric Transmission Co. (METC) proposed that it construct a new 138-kV substation, build 1.5 miles of new 138-kV line and rebuild more than 25 miles of 138-kV lines near Big Rapids, Mich., to serve a new large industrial customer. METC said approvals cannot wait on the December deadline for the MTEP approval. The project has a March 2025 in-service date and is backed by the Michigan Economic Development Corporation.

During a Wednesday task force meeting, Wolverine Power Supply Cooperative's Tom King said his utility's planned upgrade of nearby 69-kV and 138-kV lines by 2024 could help alleviate the need for some of the METC project's elements.

Thompson Adu, MISO's senior manager of transmission expansion planning, said staff will evaluate Wolverine's suggestion further. He said MISO could either consider the alternative for the second half of the project or recommend the as-is expedited request at the Jan. 25 Planning Advisory Committee.

During the meeting, stakeholders also asked whether they could propose alternative projects for the solutions outlined in expedited project requests. Adu said MISO can examine alternatives but that expedited projects are sometimes urgently needed and don't allow time for in-depth study.

The grid operator has recently fielded a steady clip of expedited project reviews to primarily accommodate new industrial load. A series of expedited project recommendations last year in MISO South led some stakeholders to question whether staff is engaging in thorough and cost-effective transmission planning and exploring alternatives. (See *Stakeholders Doubt MISO Study of Alternative Tx Projects*.)

Another expedited request from Michigan also produced concern. MISO said it found no issues with ITC's $5.5 million, 120-kV underground cable relocation to allow the Michigan Department of Transportation to begin freeway construction.

However, Consumers Energy's Rosanna Kallio said she worried that the grid operator was "blindly" recommending the project and said she had unanswered questions about the project's design elements.

Thompson said MISO would conduct further closed-door discussions on the project details of the expedited request.

The RTO did clear Henderson Municipal Power and Light's proposed 161-kV line reroute to make way for a new recycled paper mill in Kentucky. The $160,000 tap project is necessary to accommodate Big Rivers Electric's previously approved $20 million transmission project to accommodate the mill's new load. That project was also an expedited request under MTEP 22.

MISO also said it found no reliability issues with Arkansas Electric Cooperative's plans to add 50 MW of capability to a pair of Mississippi County Electric Cooperative substations. ■

Line inspection by helicopter in 2022 | *ITC Michigan*

MISO News

Software Expert Promotes DER's Impact at MISO Task Force

By Amanda Durish Cook

| *Shutterstock*

Alan Gooding, co-founder of the United Kingdom's Smarter Grid Solutions software company, told MISO stakeholders Thursday that distributed energy resources are going to be a "very large part of the energy mix going forward" with emerging technologies that are already affecting the system.

Speaking during a conference call with the RTO's DER task force, Gooding said large customers are drawn to DERs for price security and as a hedge against global energy scarcity. He said with the industry facing electrification's increased demand to fuel "heat, transport, cooling and industrial processes," companies will have to reimagine and retool the grid as part of a massive infrastructure development.

"All of that increased demand, four, five times the demand … will have to be supplied by green energy at the point of use. We're talking about having to do this within my lifetime," Gooding said.

He said utilities will need to create DER management systems (DERMS) to access the resources' full value. DERs need autonomous systems that produce demand and generation forecasts and form dispatch plans, he said.

Gooding said a "maturing sector understanding of DERMS is creating increased confidence to act," with many DERMS' requirements quickly becoming standardized. He also said utilities face a range of DER integration challenges that include managing congested interconnection queues, staffing issues, digitalization challenges, data security, grid modernization, and adapting business models.

"We see every utility is going to be on its own DERMS journey," Gooding said. "We think there's still quite a journey to go here. Regulations are going to have to catch up with what these assets can technically provide."

The industry has "so, so much to go" in how DERs interconnect and how the markets adapt, Gooding said. He said DERMS will be key to creating an "integrated 'ecosystem' of new and existing systems."

He also said utilities want to understand how the software works and are no longer looking for their vendors to provide a "black box piece of technology."

MISO plans to host another DER guest speaker in April. It tentatively plans to gain perspective from a nonprofit DER registry.

The grid operator is awaiting FERC's decision on its plan to delay integrating DER aggregations into its wholesale markets until 2030. (See *MISO Defends 2030 Completion for DER Market Participation*.) ■

MISO News

MISO Begins LRTP's 2nd RFP Process

By Amanda Durish Cook

MISO held an informational meeting last week on its second request for proposals coming out of its $10 billion long-range transmission portfolio (LRTP).

The newest project up for bids is a 345-kV *project* crossing the Iowa-Missouri state border. Proposals are due by May 19 with a developer to be selected by Oct. 31, staff told stakeholders during a Thursday teleconference.

The $161 million Fairport-Denny project involves construction of a 345-kV substation in Iowa and two 345-kV transmission lines to Fairport, Mo. Developers can submit separate bids on the project's three elements. MISO expects the project to be in service in June 2030.

The RTO's Board of Directors approved the 18-project LRTP package of 345-kV lines in July. Only about 10% of the portfolio will be competitively bid because of existing right-of-first-refusal laws and upgrade work. (See *MISO Board Approves $10B in Long-range Tx Projects*.)

The Fairport-Denny RFP is the *fourth* MISO has issued and is the first it will manage and evaluate simultaneously with other open RFPs.

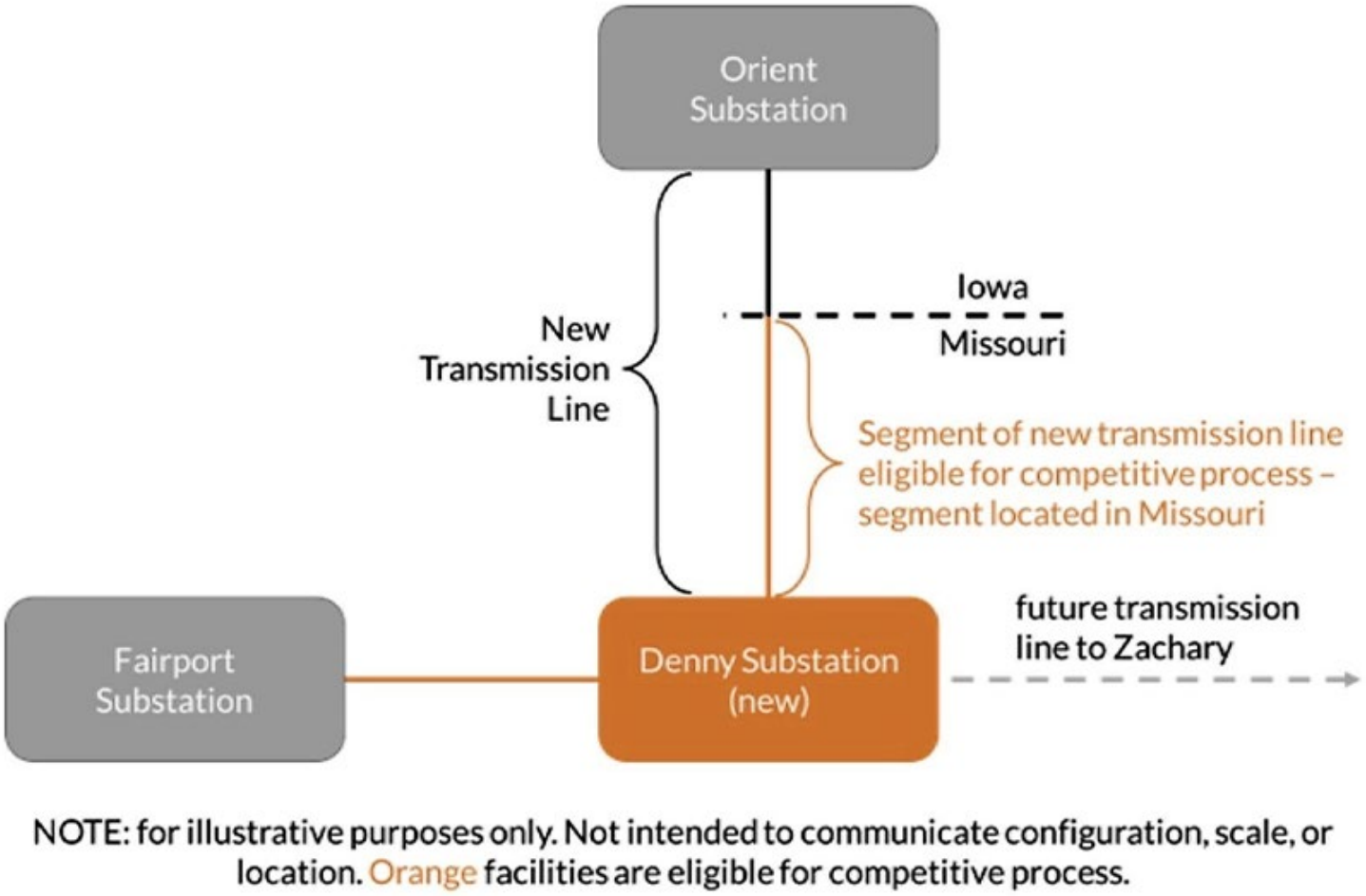
The grid operator in September released an RFP for a $254 million 345-kV project on the Indiana-Michigan state border. It expects to announce a developer for that work on May 11.

MISO will release its third RFP on March 6 for a $556 million 345-kV project that will link up with the Fairport-Denny project. Developers have until February to become certified to bid on the line.

The RTO requires its transmission developers to be members and prequalified to bid on competitive projects. Developers must include a $20,000 application fee and a $100,000 initial deposit to have their bids considered.

Brian Pedersen, senior manager of competitive transmission services, said two other RFPs will be released in July. MISO plans to open bidding periods for a $12 million, 345-kV project in Wisconsin on July 11 and a $23 million, 345-kV segment from the Iowa-Illinois border to an Illinois substation on July 24.

For transparency's sake, MISO has instructed stakeholders to send all questions regarding the competitive process to *TDQS@misoenergy.org* instead of individual personnel. The RTO also prohibits stakeholders from directing questions about competitive projects to interconnecting incumbent transmission owners while an RFP is active. ■



A simplified depiction of the Fairport-Denny project | *MISO*

NYISO News

Study Makes Case for Storage as Transmission in NY

Industry Organization Says Flexibility Would Aid Buildout

By John Cropley

The energy storage units planned in great number in New York can also serve the state's grid as transmission assets, a new study finds.

The *white paper report* — prepared for an organization advocating the advance and adoption of storage technology — uses actual and potential use cases to demonstrate the savings that could be realized by strategic use of storage rather than construction of new transmission lines.

William Acker, NY-BEST | *NY-BEST*

The New York Battery and Energy Storage Technology Consortium (*NY-BEST*) released the report Jan. 9 and followed up with a webinar Thursday. The report concludes that New York tariff and planning rules are an obstacle to exploiting storage as a transmission asset (SATA). William Acker, executive director of NY-BEST, told *RTO Insider* that the organization hopes to change this.

Along with a smaller price tag than transmission lines, storage offers a smaller footprint, a quicker installation time frame, and the flexibility to grow, shrink or relocate to adapt to what is likely to be a fluid state strategy during the clean-energy buildout, Acker argued.

Not mentioned in the report is the lifespan of batteries that are presently the dominant form of energy storage. They would need to be replaced long before transmission equipment would.

But the three use case studies projected that transmission wire solutions would cost 146 to 583% more than the initial capital costs for SATA, Acker said.

"You're looking at numbers that allow for multiple replacement of storage," he said.

Introducing the webinar, he noted New York's plans to rapidly and radically increase use of green energy generation.

"We're going to have an exceptionally large need for transmission and distribution buildout to support the decarbonization of the grid, the new renewable energy assets and the electrification of transportation and heating," he said. "We're looking at opportunities where storage can be used to make that buildout more efficient and cost-effective to consumers."

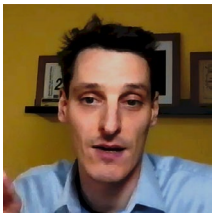
A new report examines the potential value of energy storage as a transmission asset in the future power grid in New York. | *Shutterstock*

Henry Chao, Quanta Technology | *NY-BEST*

Quanta Technology Vice President Henry Chao, who took the lead in preparing the study for NY-BEST, spoke of multiple potential benefits of SATA, including the flexibility to handle the gradual buildout of new power sources over the course of many years.

"Storage can help you to shave the peak and then add incrementally," he said. "Eventually, five [to] 10 years later, you have to build transmission, but in the interim, those incrementally added renewables will not have to be subject to curtailment."

Lars Stephan, senior manager of policy and market development at the energy storage firm *Fluence*, described one of the real-world use cases cited in the study: a 450-MW storage procurement that will allow Germany's near-capacity grid to handle the increasing flow of renewable energy as the buildout of new transmission drags far behind the initial timetable.



Lars Stephan, Fluence | *NY-BEST*

"We're seeing mounting costs of congestion in the German grid," Stephan said. The cost totaled about 2.3 billion euros in 2021, he said, and multiplied in 2022 as the energy market reeled from the Russian invasion of Ukraine.

"As a measure to counter this, the German grid operators came up with the idea to use batteries as so-called grid boosters. … The fundamental principle is to use batteries to replace the N-1 requirement in grid operation."

New York Gov. Kathy Hochul is proposing to double the target for energy storage installed statewide by 2030 to 6 GW, and most decarbonization scenarios call for much more storage capacity installed by 2040, to compensate for daily and hourly fluctuations in wind velocity and sunlight intensity. (See *NY Proposes Credit System to Fund 6 GW of Energy Storage*.)

In this environment, energy storage can serve as a power asset or a transmission asset, Acker said. "It gets complicated because storage in many cases can be both."

What NY-BEST would like to see is for storage to be able to be compensated as either in New York. There are situations, Acker said, where payment through the power market mechanisms will not work and compensation through other rate mechanisms as a transmission asset is necessary. But it is not possible now.

NYISO told *RTO Insider* that today it will announce a project to examine SATA as a possibility in the markets it administers.

The ISO said its tariffs treat storage as a generator rather than a regulated transmission asset, but SATA's unique characteristics would allow it provide many potential services to the grid.

NYISO's stakeholder engagement plan calls for a first-quarter review of how other ISOs are considering SATA and second-quarter discussions on incorporating SATA into planning processes and consideration of market participation rules and operating rules. ■

NYISO News

NYISO Finalizing CRIS Tariff Revisions

By John Norris

RENSSELAER, N.Y. — NYISO on Wednesday *presented* the Installed Capacity Working Group/Market Issues Working Group with a proposed timeline for finalizing tariff revisions related to capacity resource interconnection service (CRIS) expiration and transfer rules for deactivated facilities looking to adjust their unexpired CRIS rights.

The ISO's Nikolai Tubbs told stakeholders that NYISO would be finalizing the discussion on tariff provisions related to the CRIS project, which has been an extended ongoing process. (See "Tariff Revisions on CRIS," *Study: NYISO Dynamic Reserves Could Lower Congestion, Costs*.)

Currently, NYISO anticipates these new provisions to go into effect in the second quarter, or 60 days after they have been filed with FERC toward the end of the first quarter.

Scott Leuthauser of Hydro Quebec Energy Services asked about the status of external CRIS and whether it would be affected by any of the proposed revisions. NYISO attorney Sara Keegan answered that those rights would be unaffected.

Howard Fromer, who represents the Bayonne Energy Center, asked when NYISO expected the proposed requirements for CRIS transfers would go into effect and what the ISO meant by "functional requirements," which NYISO expects to be their 2023 deliverable.

Zach Smith, vice president at NYISO, responded that "all of the rules will become effective upon FERC acceptance," including the requirements related to CRIS transfers.

Smith then clarified that the functional requirements that NYISO is seeking to deliver by the fourth quarter relate to partial CRIS expiration, and the ISO "needs software tools to facilitate the partial CRIS tracking." Smith also told stakeholders that the first time NYISO will "expire someone under the new partial CRIS rules would be three years from the effective date."

Mark Younger, president of Hudson Energy Economics, thought it was confusing that NYISO "have the deliverable for this year called 'functional requirements,' when, in fact, the real deliverable is implementation."

Doreen Saia, an attorney with Greenberg Traurig, asked whether the tariff revisions specifically related to the same-location CRIS transfers rules, would be impacted by the Class Year 2023 base case lockdown.

Keegan responded that it would not, and that, "regardless of this filing, CRIS transfers would be requested by the class year start date."

NYISO will seek approval for the proposed CRIS tariff revisions at both tomorrow's Business Issues Committee and the Jan. 25 Management Committee meetings. ■

No.	Proposal	December 2022	January 2022	Q1 2023	~End of Q1 2023	Q2 2023
(1)	CRIS modeling in deliverability studies	Finalize Tariff revisions	BIC and MC Approval	Board approval	File with FERC	*Proposed effective date of the tariff provisions:* *60 days after filing with FERC*
(2)	CRIS retention/ voluntary termination					
(31)	Partial CRIS expiration for internal facilities					
(4)	Partial CRIS expiration for UDRs/EDRs					
(5)	CRIS Transfers					

NYISO's proposed timeline for CRIS expiration | *NYISO*

NYISO News

2023 Preview of NY Legislature on Energy and Environment

By John Norris

ALBANY, N.Y. — The New York State Legislature has started its 2023 session and is poised to take up many bills that build on the Climate Leadership and Community Protection Act (CLCPA).

Both *Senate* and *Assembly* committees will soon hold hearings on bills seeking to improve economic conditions for ratepayers, establish market rules that comply with the CLCPA and protect New York's natural resources. The bills, among hundreds of others already in front of the legislature, include:

- *S334*, to update requirements for electricity bills;
- *S404* and *S402*, to develop more residential advanced metering and microgrid energy storage;
- *S737*, to provide net revenue from renewable generators to low-income customers;
- *S453*, to review 18-month gas rate scheduling;
- *S1487*, to mandate that the governor alone select the two candidates for the locally nominated seats on the state Board on Electric Generation Siting and the Environment;
- *S1275*, to increase the number of trustees on the New York Power Authority by two, and mandate that the new seats be held by a resident of Niagara County and of St. Lawrence County; and
- *S374* and *S592*, to add conditions for transmission approvals and renewable siting.

New York State Capitol | © *RTO Insider LLC*

Other bills target environmental conservation through creating carbon dioxide pricing mechanisms; establishing a public water justice act; authorizing forest rangers to train search-and-rescue volunteers; and requiring annual climate expenditure reports (*S732*, *S238*, *S28*, *S288*).

Republican Priorities

Senate Minority Leader Robert G. Ortt last week *outlined* Republicans' "Rescue New York" *agenda*, which includes calls for increasing energy affordability, stemming the flow of capital from the state, enacting climate policies that ensure affordable and reliable energy, and eliminating burdensome regulations.

State Sen. Robert G. Ortt delivers Republican 2023 priorities. | *New York Senate*

In an email to *RTO Insider*, Ortt argued that "everyone agrees we need to move toward a clean energy future, but we need to do so by supporting common-sense energy policies that work."

"The unachievable goals and radical policies set out by the Climate Action Council will only continue to drive New York residents and businesses elsewhere," Ortt said. Republicans have "repeatedly requested a cost-analysis because we must understand the real implications that are going to land on the backs of New York's ratepayers."

The Republican agenda includes opposing proposed bans for natural gas hookups, requiring independent cost studies of all the CAC's proposals and supporting burgeoning technologies, such as advanced nuclear and hydrogen.

One of the bills Ortt is *sponsoring*, S592, would prohibit siting wind farms within 40 miles of military installations. It is in response Apex Clean Energy's proposed Lighthouse Wind

NYISO News

Project in the towns of Yates and Somerset. The Niagara Falls Air Reserve Station is about 30 miles away from Somerset.

"The Niagara Falls Air Reserve Station is too much of an asset to Niagara County and our entire region to put its future at jeopardy with this proposed project," Ortt said. "We cannot risk hindering the air base's operations, security and potential new missions."

Democratic Outlook

Assemblymember Didi Barrett (D), the newly elected chair of the Assembly's Energy Committee, told *RTO Insider* that she plans on "supporting innovative energy generation practices and technologies, and working with state, local and community leaders to develop and to support the siting of renewable energy in an equitable and sustainable manner."

Barrett said she will "develop thoughtful legislation that will help us meet our goals through a just energy transition." The CLCPA emphasizes "the important balance between reaching our ambitious climate goals while protecting communities across New York."

She also said she does not believe energy is a partisan issue, highlighting how she has "sponsored and passed numerous bills on a range of issues with bipartisan support" and "stands ready to work with colleagues in both parties and both houses to forge a path forward."

Despite differences on what actions need to be take, which issues should be prioritized or what policies will be most effective, Barrett said legislators align on the fact that New York is at a critical stage and that actions taken this year will have a massive impact on the future.

Environmental Expectations

Climate action organizations are calling on politicians to uphold this year's promises, particularly those made in Gov. Kathy Hochul's State of the State address. (See *Hochul Highlights Cap and Invest in State of the State Address*.)

The New York League of Conservation Voters' (NYLCV) recently released 2023 legislative *priorities* call for more offshore wind development, the creation of a clean fuel standard, more investment in green jobs and education, enhancement of coastal resilience, more funding for agencies charged with energy resources, and improvements to the access and quality of natural resources.

In an email to *RTO Insider*, NYLCV Policy Director Patrick McClellan said, "No silver bullet exists to solve the climate crisis overnight, or even in a couple years, but if we make the right decisions now, New York will be better prepared to withstand the impacts of climate change in the coming years."

McClellan believes "it's imperative that the state increase its offshore wind capacity through the timely procurement, responsible siting, government permitting and the transmission of 9 GW of offshore wind by 2035, while increasing our offshore wind goal to 20 GW by 2050."

The Alliance for Clean Energy New York's (ACE NY) 2023 legislative *agenda* closely aligns with *legislation* the organization supported previously.

It calls for bills that help renewable projects overcome construction barriers, codify state operations being powered entirely by renewables, promote clean transportation and buildings efforts and exempt energy storage resources from the sales tax.

ACE NY "supports legislation that enhances market opportunities for large-scale, grid-connected renewables; for smaller-scale distributed renewable energy; for energy efficiency; and the electrification of transportation." It opposes bills that "would unduly or unfairly restrict clean energy development in New York state." ■

Assemblymember Didi Barrett (middle) on the Assembly chamber floor | *Didi Barrett*

NYISO News

NYISO Completes Class Year 2021 Projects

RENSSELAER, N.Y. — NYISO on Friday *announced* that it had completed the final interconnection studies for its Class Year 2021 (CY21) group of projects.

The 27 wind, solar, energy storage and transmission expansion projects, which total 7,452 MW, had gone through multiple rounds of decision-making. (See "Class Year 2021," *NYISO Operating Committee Briefs: Dec. 15, 2022*.) Assuming NYISO sticks to its timetable, Class Year 2022 will begin the week of Feb. 12. (See "Decision Process and Timeline," *NYISO Class Year 2021 Cost Allocations Advance to OC Vote*.)

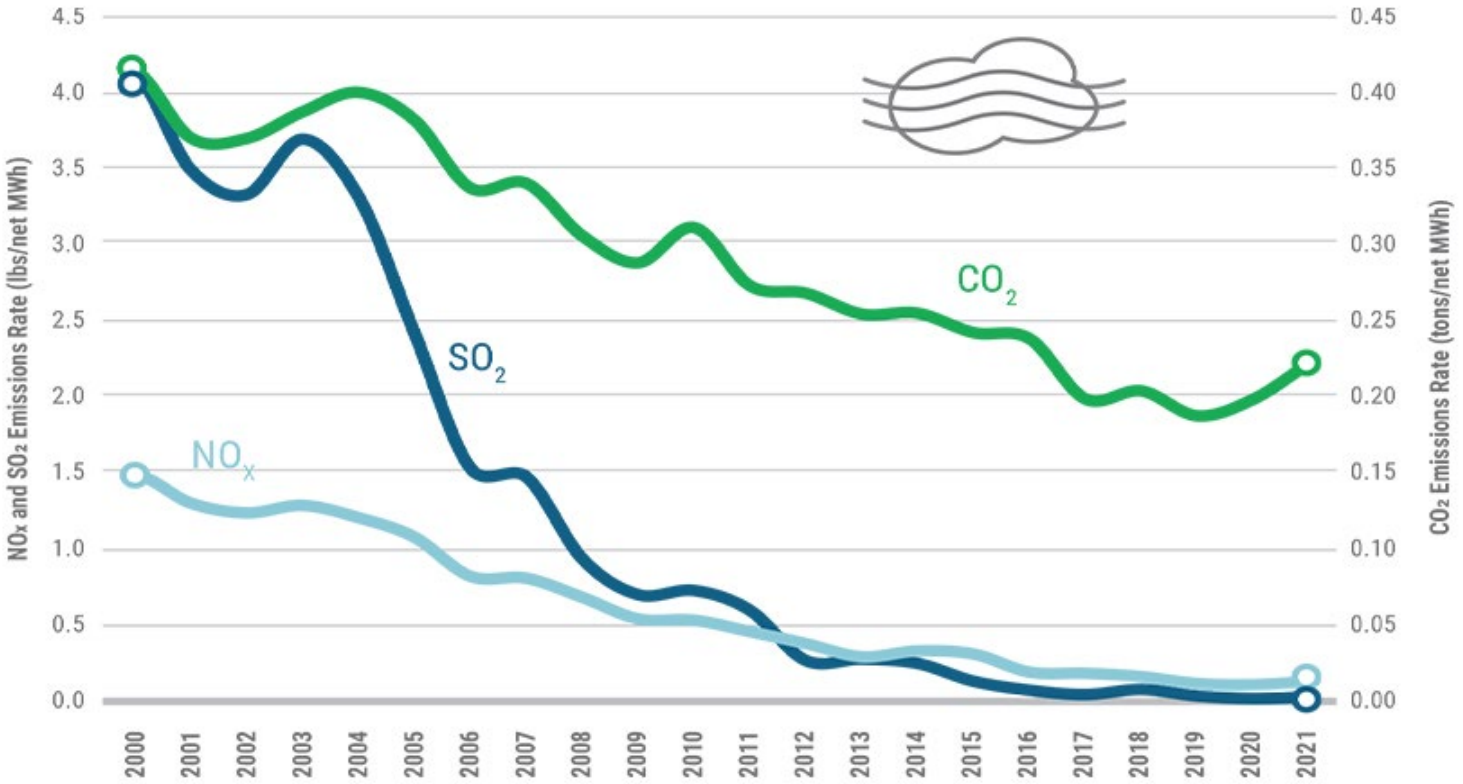
"These projects will help move the state closer to the ambitious clean energy mandates of the Climate Leadership and Community Protection Act," Zach Smith, vice president at NYISO, said in a statement. "As pleased as we are with this major accomplishment, we're already preparing to begin the next class year."

In an accompanying *white paper*, NYISO has sought to accelerate the Class Year process by balancing flexibility with grid reliability because of the influx of new projects in the interconnection queue.

These efforts have included eliminating elements of the system reliability impact study, engaging stakeholders in the interconnection process more and improving the management of "material modification" requests from developers.

NYISO said it is also investing in its engineering, legal and technical teams to ensure projects move quickly through the interconnection process without sacrificing critical analysis needed to support grid reliability. ■

— John Norris



NY emissions rates from electric generation | *NYISO*

Northeast news from our other channels

Hochul Highlights Cap and Invest in State of the State Address — NetZero Insider

NY Company Plans 60-stall EV Charging Station for Queens — NetZero Insider

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

PJM News

PJM Gas Generator Failures Eyed in Elliott Storm Review

More than One-third of Gas Units Unavailable Dec. 24

By Rich Heidorn Jr. and Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM expects to issue at least $1 billion in penalties over generation outages during Christmas weekend, when plummeting temperatures stretched the region to its limits, RTO officials *told* stakeholders last week.

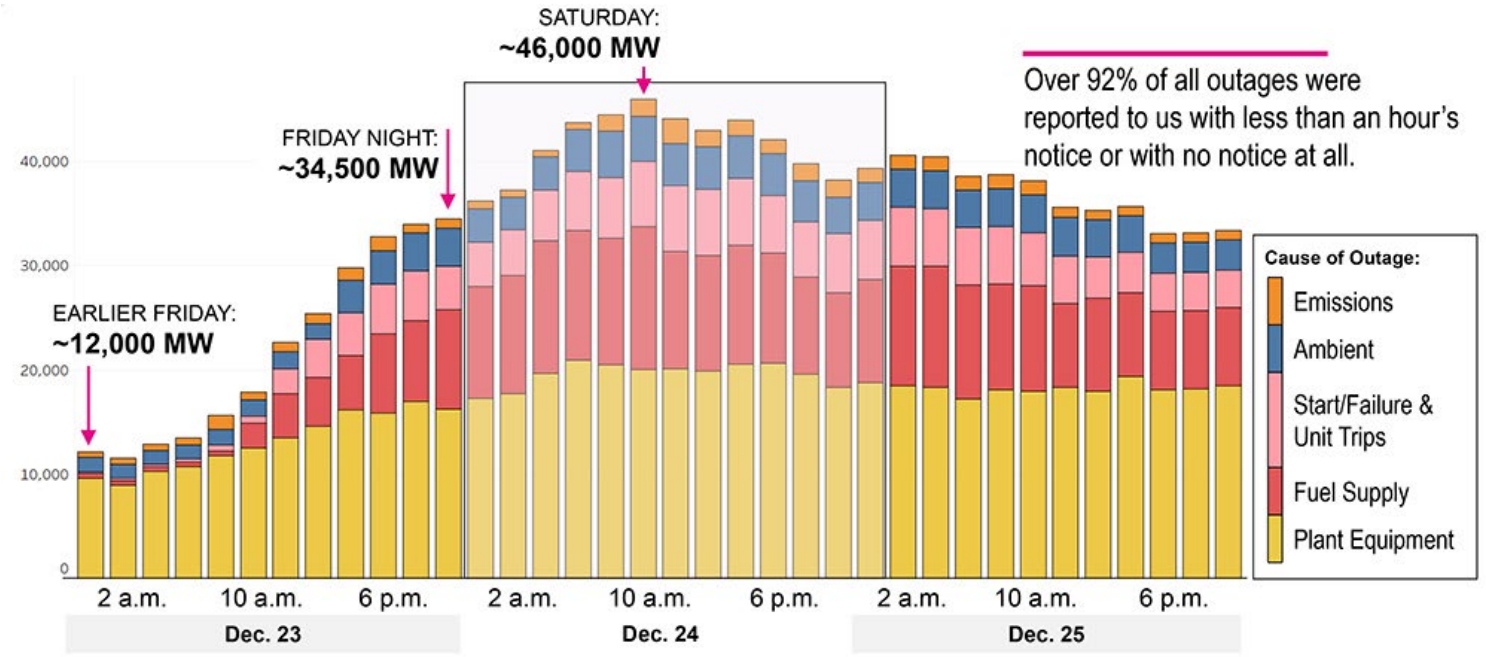
PJM reported 46,000 MW of forced outages during Winter Storm Elliott on Dec. 24, representing more than 23% of its capacity and including almost 38% of its natural gas capacity. More than 92% of forced outages were reported to PJM with less than an hour's notice — or with no notice at all.

"A large portion of our generation fleet failed to do what was required of them," Donnie Bielak, PJM's senior dispatch manager, told the Market Implementation Committee during a presentation Wednesday on the storm's impact.

Although demand response and consumers' conservation actions helped PJM avoid shedding load, the RTO was forced to cut exports to the Carolinas and the Tennessee Valley Authority, where there were load sheds.

Winter Storm Elliott was the fifth event in 10 years in which reliability was jeopardized by unplanned generating unit outages in cold weather. It came less than two years after Winter Storm Uri in February 2021 resulted in the largest firm load shed event in U.S. history.

PJM's Donnie Bielak briefs the Market Implementation Committee on Winter Storm Elliott on Dec. 11. | *© RTO Insider LLC*



PJM lost about one-quarter of its generating fleet — including 38% of natural gas units — after temperatures plunged over Christmas weekend. | *PJM*

PJM News

FERC and NERC announced Dec. 28 they would investigate the response to Elliott. (See *FERC, NERC Set Probe on Xmas Storm Blackouts*.)

Temperatures dropped 29 degrees Fahrenheit, from about 36 F to 7 F, within 12 hours on Dec. 23, the "most drastic" drop in more than a decade and lower than weather forecasts had predicted, PJM said. That contributed to a load forecast that fell 10% below actual load.

Trying 'to Stress Us Out'

Bielak told the Operating Committee in a second discussion Thursday that control room operators were "heavily, heavily strained" trying to maintain reliability through the valley period overnight Dec. 23 before the Christmas Eve morning peak.

"We just kept losing units. … It didn't stop," Bielak said.

He quoted a control room colleague, who remarked that it was like the dispatchers' training in the PJM simulator, where instructors throw repeated outages at them "to stress us out."

The Christmas Eve valley was the highest in the last decade and 40,000 MW higher than the second highest.

The extreme outages limited PJM's ability to replenish pond levels at pumped storage sites before the Christmas Eve morning peak. "We were mortgaging the future," Bielak said. "If we didn't get through the valley there would be no peak anyway."

30% Gas Supply Drop in Utica, Marcellus Shale

While some gas units tripped or were unable to start because of the cold, other units lacked fuel as a result of a 30% drop in gas production from the Marcellus and Utica shale regions. That repeated a pattern seen in Winter Storm Uri, when there were major production cuts in Texas and the Southwest.

Brian Fitzpatrick, PJM's principal fuel supply strategist, said the RTO holds weekly meetings with pipeline operators between November and March to discuss electric and gas load forecasts and pipeline restrictions. "Those conversations ramped up" leading to the storm, he said, and the RTO monitored the interstate gas pipelines. But he acknowledged that "there is no bulletin board" providing the RTO real-time information on gas production. "We don't see supply numbers until the next day," he said.

Fitzpatrick said PJM's challenge was the speed at which the load changed and how quickly the pipeline line pack diminished between late morning and late afternoon on Dec. 23.

Paul Sotkiewicz, of E-Cubed Policy Associates, said he was shocked by the reduced Marcellus production but noted some of his clients' gas units faced pipeline reductions even where production cuts were not an issue.

Fitzpatrick said PJM does not know why production was cut but that it will likely be a focus of the FERC-NERC investigation. "My assumption is that it's predominantly related to well freeze-offs. But were those well freeze-offs caused by something else? Was it a lack of manpower because of the holiday?" he said. "It wasn't an absolute temperature issue necessarily. … The issue was how rapidly it got cold; right before the event it was very warm."

Why Didn't CP Fix This?

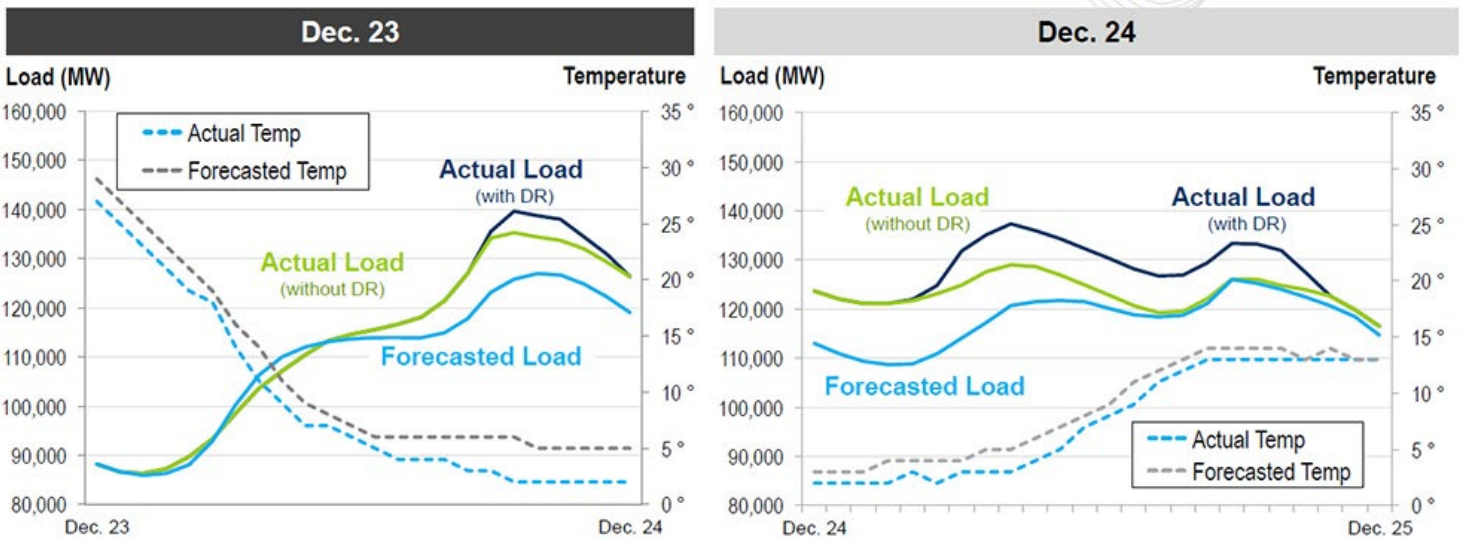
Christi Tezak, of ClearView Energy Partners, questioned why PJM's Capacity Performance structure appeared to have led to higher outage rates compared to similar colds snaps in the past.

CP, which increased penalties for failing to deliver and bonuses for overperforming, was enacted in response to the 22% forced outage rate during the 2014 polar vortex.

"The whole point of CP was to provide those incentives on the front end" to prepare for winter weather, said PJM Senior Vice President of Market Services Stu Bresler. He said the RTO was seeking additional information from generators on their poor performance. "We have the same questions as you do," he said.

Penalties

PJM estimates that the non-performance charges for generators will be between $1 billion to $2 billion. However, it cautioned that the figure is preliminary and includes facilities that may have permissible reasons to be excused. Given the scale of the penalties, PJM will be providing individual resource perfor-



Temperatures dropped from about 36 degrees to 7 degrees within 12 hours on Dec. 23, the "most drastic" drop in more than a decade and lower than weather forecasts had predicted. That contributed to a load forecast that fell 10% below actual load that day. | *PJM*

PJM News

mance data to operators before it levies the charges, with the aim to have that sent out by the first full week of February.

"Right now this data only includes preliminary excuses for being scheduled down for economic dispatch," PJM's Susan Kenney said Wednesday.

Stakeholders in the generation sector complained they were both being held responsible for natural gas pipeline failures and being held to the capacity needs of other regions.

Throughout most of the weekend, PJM continued to be a net exporter of energy to surrounding regions, though efforts were taken to curtail the outward flow. Bielak said PJM are not "isolationists" and were not going to cut exports that would push other regions into load shedding.

One stakeholder who asked not to be identified questioned whether the penalties could cause disruptions to the markets should a significant number of generation owners go into default.

He asked "are we potentially moving towards a situation where markets are stressed due to" large numbers of participants going into default?

PJM CFO Lisa Drauschak said that while failure to pay does constitute a default, stakeholders are not responsible for any undercollection as it is subtracted from the bonuses paid out. In timing the payments, she said staff is taking into account non-payment risk and the RTO's liquidity to ensure that there is no risk to stakeholders.

Erik Heinle of Vistra questioned whether the data gathering over the penalties could prompt a delay in 2025/26 Base Residual Auction slated for June.

"We agree it's a question; it's something we're thinking about," Bresler said. But the RTO hasn't committed to changing any dates, he said.

Verifying Outage Causes

PJM said more than 92% of all outages were reported to the RTO with less than an hour's notice, or with no notice at all.

Yet, when outages peaked at about 46,000 MW on the morning of Dec. 24, less than 15% of the lost capacity was attributed to start failures and unit trips, which occur without prior notice.

Bielak said dispatchers were calling operators who had not reported any problems and were informed "we can't run."

"Well, you should have had that note in … eDART [the dispatcher application and reporting tool] so we wouldn't have bothered trying to call you," Bielak said.

Dave Mabry, of the PJM Industrial Customer Coalition, said it appeared PJM suffered a "loss of situational awareness" during the storm.

"We really, really rely on members to tell us what the status of their units and parameters are … going into any kind of significant weather, but also on a daily basis because that's how we make decisions," said Senior Vice President of Operations Mike Bryson.

In response to a question from Tyson Slocum, energy program director for Public Citizen, Bryson acknowledged that PJM does not do any validation of the outage causes cited by generators. "If the unit was out, it's going to be subject to a" penalty regardless of the cause, he said.

Slocum said companies with multiple units have an incentive to prolong scarcity events by providing misleading outage data because the CP penalties may be exceeded by CP bonus payments and revenue from high prices.

Sotkiewicz took offense at Slocum's "implication that games are being played" by generators. "Trust me. We would want to be running," he said, citing PJM's estimate that penalties could total $2 billion.

PJM's Chris Pilong said generators record the outage cause in eDART in real-time but provide more detail later in NERC's Generating Availability Data System.

Monitoring Analytics President Joe Bowring said the Independent Market Monitor will be reviewing "every single outage," adding, "we don't think the reporting was entirely accurate."

NERC Winter Standards Not Strict Enough

PJM officials said the Christmas storm experience underscored the RTO's concerns that NERC's proposed reliability standards on freeze protection for generation and natural gas facilities impacting the bulk power system are not strict enough.

Bryson said PJM's concerns were included in the ISO-RTO Council's (IRC) Dec. 8 *comments* in response to NERC's Oct. 28 petition for approval of proposed Reliability Standards EOP-011-3 and EOP-012-1.3 (RD23-1). (See *FERC, NERC See Progress on Winter Weatherization*.)

The IRC said NERC's proposal to use weather data since only 2000 "is not indicative of the actual extreme weather conditions that units may experience in the PJM region."

Bryson said the RTO also is concerned with the "somewhat casual ability for generators to opt out of the standard."

The IRC cited language allowing generators to reject the requirements based on a "commercial" constraint.

"Given that it is not at all clear how costly a measure must be before it presents a 'commercial' constraint, or how any such standard could be fairly applied both to independent power producers and to vertically integrated utilities subject to rate regulation, the IRC is concerned that these requirements as drafted will encourage generators to avoid making improvements, particularly if a competitor elects to utilize this 'opt-out' to gain a competitive advantage by avoiding the capital expenditures necessary for compliance," it said.

Is Gas Unreliable?

Greg Poulos, executive director of the Consumer Advocates of PJM States, asked whether the events had raised questions about the reliability of gas. Bielak said it was too soon to draw any conclusions but said the RTO was taking additional steps to maintain reliability for the rest of the winter.

PJM officials said there will be additional discussions of the Christmas event at the Electric-Gas Coordination Senior Task Force *meeting* this Thursday. ■

PJM News

PJM Planning Committee Endorses Capacity Accreditation for Renewables

By Devin Leith-Yessian

The PJM Planning Committee on Jan. 10 *endorsed* a proposed solution for capacity accreditation of intermittent resources under the effective load-carrying capability process.

Out of the *five proposals* before the committee, PJM's Package I received 82.4% of stakeholders' support. The proposal's central feature is a transitional mechanism to allow resources seeking higher capacity interconnection rights (CIRs) to temporarily receive a higher capacity rating. (See *PJM Stakeholders Review Proposals on CIRs for ELCC Resources*.)

Only Package I cleared the 50% support threshold to advance to the Markets and Reliability Committee. PJM's Package D received the next highest degree of support, with 34.9%. LS Power's Packages K and E received 29.3% and 24.1% support, respectively, while Package G from E-Cubed Policy Associates was endorsed by only 7.1%.

How to define existing resources' capacity rating until a permanent solution can be implemented remained the main sticking point throughout the PC's discussions of the issue. Most of the proposals, including Package I, would require resources seeking a higher accreditation to re-enter PJM's interconnection process at the end of the queue, which has been mired in a backlog spanning years.

Package I would also allow resources to utilize existing headroom on the transmission system through a transitional system capability study, though it would also cap the actual accreditation at the facility's existing CIR. That headroom would be available so long as it is not claimed by another resource's CIRs and until PJM has completed the process of transitioning to its new methodology of studying interconnection requests.

To be eligible to participate in a transitional study, the additional capacity must be deliverable without any physical modifications made to the generation resource, and an uprate request must be submitted to PJM.

During a special MRC *meeting* to "page turn" the proposal Friday, PJM's Jonathan Kern said the RTO's goal is to open a 30-day window for submitting uprate requests that would close on March 3.

Stakeholders noted that if the proposal was to be approved by the MRC and the timeline implemented, the window would be opening prior to FERC approval of the changes. Kern said the timing is envisioned to allow PJM to jump on implementation following a prospective commission approval and have everything ready to be included in the 2025/26 Base Residual Auction (BRA) scheduled in June.

"One of the primary goals here is to accomplish all of this in time for the 2025/26 BRA," he said, noting that the target was part of the package approved by the PC. "We're committed to making this happen, and this 30-day window is essential, PJM believes, to make this goal."

The second-highest vote getter, Package D, was the only proposal that would have granted higher CIRs outside of the interconnection process. New deliverability tests would been conducted and been the basis for granting the higher CIRs for existing wind and solar resources starting with the 2023 Regional Transmission Expansion Plan. It was also the only proposal that would have allocated the cost of any transmission upgrades necessary to accommodate the higher capacity ratings to load rather than the generators.

LS Power's Package K was built off PJM's prevailing proposal but included a request that the RTO's Board of Managers direct staff to submit a filing with FERC clarifying that the Reliability Assurance Agreement establishes CIRs as the hourly upper limit for unforced capacity accreditation starting with the 2025/26 BRA.

The company's other proposal would have immediately limited accreditation to a generator's CIR level and required those seeking higher accreditation to re-enter the interconnection process at the end of the queue.

While Package E received the highest share of support in an October poll at the PC, PJM overhauled its Package I to include the transition studies and later expanded eligibility to all resources; originally only intermittent generation would have been permitted to utilize the existing headroom.

Package G would have also required resources to re-enter the transmission queue to receive higher accreditation, while also expanding deliverability testing into the shoulder months to capture increasing reliability concerns being seen in those seasons. ■

Jonathan Kern, PJM | © *RTO Insider LLC*

PJM News

FERC Approves Pipeline Expansion Despite New Jersey's Worries

State Study Found No New Gas Pipelines Needed

By James Downing

FERC on Wednesday approved an expansion of the Transcontinental Gas Pipeline (Transco) despite a study from New Jersey state agencies finding it was not needed and that its utilities should use alternative sources of supply (*CP21-94*).

The Williams Companies' proposed Regional Energy Access Expansion project includes upgrades to the existing pipeline in Pennsylvania and New Jersey to increase deliveries to the East Coast by 829,400 dekatherms per day, mostly into New Jersey, at a cost of about $950 million. The Transco pipeline includes 10,000 miles of pipe that bring gas from Texas and other areas on the Gulf Coast to New York City.

The New Jersey Board of Public Utilities and the Division of Rate Counsel argued that new capacity is not needed for the local distribution companies who signed contracts with Transco. The BPU commissioned a study from London Economics International that found that LDCs can easily meet their firm winter demands through 2030 using existing pipeline capacity. The board has directed them to consider non-pipeline alternatives to ensure they have enough gas capacity.

The New Jersey agencies' arguments were backed by several environmental groups, who noted that the state is working to get to net-zero carbon emissions by midcentury.

Transco hired Levitan & Associates to do its own study, which found that LDCs in New Jersey and the Philadelphia area would fall short of needed supplies starting this decade and that the situation would only get worse without new infrastructure.

FERC said it found both studies useful in its decision, but it noted that they have different inputs that may reflect differences in risk tolerance for meeting demand on extremely cold days.

"After due consideration of both studies and other evidence as discussed, the commission finds that the construction and operation of the project will provide more reliable service on peak winter days and will provide cost benefits by increasing supply diversity," FERC said.

Sierra Club argued that the pipeline was not needed because both Pennsylvania and New Jersey have laws that require cutting greenhouse gas emissions by 80% by 2050, but FERC said that is not enough to undermine its finding that Transco had demonstrated a need for the project. Some of the gas would flow to other states including Maryland, Delaware and New York, the commission noted.

| *Shutterstock*

The order drew additional statements from three of the four FERC commissioners.

While ultimately concurring with the order, Commissioner James Danly dissented from the majority's decision to stay the project's certificate so that the commission could process any requests for rehearing. He also argued that the commission should focus on precedent agreements as the main way for showing a project's need, something that FERC under former Chair Richard Glick had proposed not to do.

Commissioner Allison Clements also concurred with the order while highlighting what she called the "inadequacies" of FERC's 1999 policy statement on natural gas pipeline certificates.

"Twenty years ago, the commission was primarily concerned about assuring there would be sufficient natural gas transportation capacity to serve growing demand for natural gas," Clements said. "Now, a combination of market forces and federal, state and local climate protection policies may lead to flat or declining demand for natural gas over time."

Clements also argued that FERC should have given more weight to the BPU's study finding no new pipeline capacity is needed in the state because she said the agency is the main regulator of the gas utilities that have signed up for 56% of the project's capacity.

Commissioner Mark Christie wrote separately to concur with the commission's decision to grant the BPU's motion to intervene out of time, saying that "the views of state officials are always due respectful consideration."

However, the former Virginia utility regulator said that the BPU's views in the case were "somewhat less than clear" because it did not explicitly ask FERC to reject the project, only to accept the findings of its study that new pipeline capacity was not needed.

"Even assuming the NJBPU is implicitly opposed to the project, the record does not indicate that the NJBPU submitted any information explaining why the local gas distribution companies in New Jersey, which entered into contracts to take natural gas supply from this pipeline — LDCs which the NJBPU regulates — were wrong to do so or could have obtained alternative sources of gas supply to serve their residential, commercial and industrial customers," Christie said. ■

PJM News

PJM MIC Briefs

FTR Bid Limit Increase Endorsed Under Fast Track Pathway

The PJM Market Implementation Committee on Wednesday endorsed a proposal to increase the maximum number of bids a single corporate entity can place in the RTO's financial transmission rights auctions from 15,000 to 20,000.

PJM is seeking to make the change under its "quick fix approach" — which allows a proposed solution to be endorsed concurrently with its issue charge and problem statement — with the aim of having the change in place for the April 2023 auction. (See "PJM Considering Increasing FTR Bid Limit of 15,000 per Entity," *PJM MIC Briefs: Dec. 7, 2022*.)

The increase is being considered based on requests from market participants and following the transition to weekend on-peak and daily off-peak class types, which effectively required traders to submit two bids to acquire or sell the same number of hours of an FTR as prior to the transition, according to the problem statement.

"We did feel this is sufficient for the type and volume of bids that we are seeing today," PJM's Emmy Messina said.

The proposal is set to go before the Markets and Reliability Committee on Jan. 25 for a first read, with a vote on endorsement slated for Feb. 23.

David "Scarp" Scarpignato, Calpine | © *RTO Insider LLC*

Stakeholders Disagree on Approach to Combined Cycle Modeling

Stakeholders deferred action on an issue charge and problem statement addressing the performance impact of expanding multi-schedule modeling to combined cycle generators in the market clearing engine (MCE).

Committee members were divided over what should be considered in the scope of the proposal, as well as whether the effort should continue before PJM releases a white paper it's currently drafting outlining the bounds of a technically feasible solution.

PJM has an ongoing MCE software contract with General Electric, which is currently in the process of overhauling the programs it provides based on feedback and goals from the RTO, including the effort to expand multi-schedule modeling to combined cycle units. Currently those generators must mimic their operating characteristics in their offers.

Most of the division centered on PJM expanding the out-of-scope topics in its issue charge to include offer structures in its day-ahead and real-time energy markets and to the three-pivotal-supplier test. Those changes were sought by some stakeholders at the MIC's December meeting and supported by PJM staff seeking to keep the discussion on a tighter time frame. (See "Feedback on Issue Charge, Problem Statement for Combined Cycle Modeling," *PJM MIC Briefs: Dec. 7, 2022*.)

PJM's Rebecca Carroll said GE is seeking guidance on how to proceed with making changes to the MCE by the third quarter of 2023. If stakeholders have not endorsed a system for multi-schedule modeling of combined cycle units by that point, GE will not proceed, she said. Under the current Next Generation Markets framework, the number of permutations that would have to be modeled for combined cycle units would not be solvable.

Paul Sotkiewicz, president of E-Cubed Policy Associates, who pushed for many of the changes PJM had made to its issue charge, said he would also like to see education from other system operators who have attempted multi-schedule approaches for combined cycle units and abandoned the effort because of the amount of time it would take.

David "Scarp" Scarpignato noted that this has been an issue discussed since PJM created a task force on generator modeling nearly a decade ago. Many of the questions raised in recent meetings have been answered in the materials created there, he said.

The Independent Market Monitor also presented its own proposed issue charge with a scope defined as pertaining to the process where software automatically chooses parameters where resources have local market power or during emergency and hot/cold weather alerts. ■

— Devin Leith-Yessian

PJM News

PJM PC/TEAC Briefs

Stakeholders Endorse Changes to Generator Deliverability Test

VALLEY FORGE, Pa. — The Planning Committee endorsed by acclamation a PJM proposed slate of *modifications* to the generator deliverability tests to reflect the higher variability in dispatch as renewable resources continue to be added to the grid.

"We feel this set of changes is necessary to move in the right direction. It needs to be included in the planning process sooner rather than later," said PJM's Jonathan Kern.

The changes include merging the summer, winter and light load testing methods, redefining the light load period to reflect solar and wind output, and harmonizing the dispatch procedures. The proposal is intended to take a procedure that is fairly prescriptive and make it more reflective of the reality of what is being seen on the grid.

"We feel that this approach is going to provide a more realistic and conservative stress level than the existing procedure," Kern said.

PJM will also be providing a software program that will allow for PJM's results to be replicated by market participants. Kern said that is expected to roll out in the spring and should prevent the changes from causing additional work for transmission owners.

The proposal is set to go before the Markets and Reliability Committee on Jan. 25 for endorsement. If approved at that meeting, it could be implemented as part of the 2023 Regional Transmission Expansion Plan (RTEP).

Load Forecast for Northern Virginia Data Centers Continues to Climb

PJM is planning to open a third competitive window for the 2022 RTEP early next month to address "unprecedented growth" in data center load clustered around Dulles Airport in Fairfax County, Va. (See *PJM Orders Dominion 'Immediate Need' Projects to Serve Load Jump in 'Data Center Alley'*)

During the Jan. 10 Transmission Expansion Advisory Committee meeting, Sami Abdulsalam, senior manager of transmission planning, *said* the region set a summer 2022 peak of 21,156 MW, exceeding the forecasted 20,424 MW. The 2023 load forecast is showing a significantly sharper trend through 2040 than the past two annual forecasts. It's anticipated that Dominion will see 4.2% to 5% annual load growth for the next 10 to 15 years and could nearly double by 2040. While PJM is still able to maintain voltages in the area, Abdulsalam said it's becoming increasingly difficult to schedule outages.

The data center growth extends to the north into FirstEnergy's APS zone, which is expected to see its load grow from an 8,412-MW peak last year to 9,568 MW in the 2028 RTEP, based on the 2023 forecast.

Though the latest forecast goes out to 2040, Abdulsalam said the RTO is only making recommendations on work needed to meet the load growth expected through 2028, which PJM feels is a proper balance between the lead time needed for projects and the risk in forecasting.

Director of System Planning Dave Souder said the Load Analysis Subcommittee worked with data center developers and operators to develop the forecast, including by visiting the region where the development is occurring.

"We have had the ability to actually go down to the Dulles Airport area, and the amount of construction is amazing," he said.

PJM Reviews Baseline Reliability Projects

PJM reviewed three proposed packages of baseline reliability projects to address violations found in the first window, second cluster of the 2022 RTEP: 26 thermal and 25 voltage flowgate violations in the APS, BGE, MetEd and PECO areas.

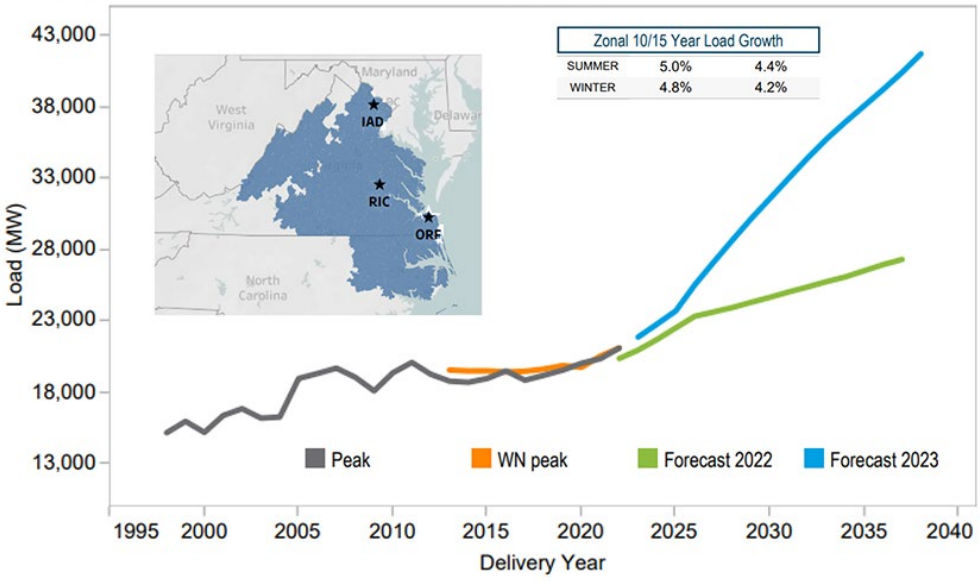
Abdulsalam *told* the TEAC Tuesday that the preferred Option 1 solution has a $154.29 million price tag, less than half the cost of the other two proposals.

Option 1 resolves all violations by making upgrades to existing facilities, whereas both alternatives include the construction of new infrastructure or major rebuilding of existing facilities. The most significant portions of Option 1 are the reconductoring of 27.3 miles of the Messick Road–Morgan 138-kV line and replacing equipment at the two substations at a $49.23 million cost.

Option 2 includes the rebuilding of the Hunterstown–Carroll 115/138-kV corridor as a double circuit 230-kV line and equipment at each substation to handle the higher voltage. At a $148.83 million cost, the work to that line would constitute nearly half of the proposal's $332.85 million cost

With the highest cost, Option 3 includes constructing a new 500/230-kV station named Rice, tapping the existing Conemaugh–Hunterstown 500-kV line and building 29 miles of new double circuit 230-kV lines from the Ringgold substation to the new Rice substation. A second new 500/230-kV substation designated Furnace Run would be built off the Peach Bottom-TMI 500-kV line. Altogether the package would cost $389.78 million. ■

— Devin Leith-Yessian



PJM's load forecast for Dominion's transmission region is continuing to grow as the rate of data center development continues to exceed expectations. | *PJM*

PJM News

PJM OC Briefs

Fuel Inventories Recovering from Winter Storm

VALLEY FORGE, Pa. — While fuel inventories fell during the cold snap accompanying last month's winter storm, PJM's Brian Fitzpatrick told the Operating Committee on Thursday that they are on track to recover.

The impact of the storm dominated the committee's *agenda* for the meeting, pushing Fitzpatrick's *presentation* to an informational-only item. (See related story, *PJM Gas Generator Failures Eyed in Elliott Storm Review*.)

Coal inventories remain within PJM's forecast, albeit at the lower end, after falling below the five-year range for much of 2022. Appalachian coal production rates are down nearly 30% relative to the last two weeks of December, though Fitzpatrick noted that end-of-the-year drop-offs are not uncommon.

Natural gas production has recovered from a freeze-off during the storm, though inventories remain within the five-year range at 2.7% below the average. Pipeline issues contributed to nearly one-third of the natural gas generation in PJM's fleet being unavailable during the storm. With those units offline, oil inventories took a significant hit: Stocks of distillate fuel oil have been far below the five-year range since 2022, and an uptick toward recovery was halted during the storm.

PJM Seeks to Close DLR Task Force

Stakeholders indicated support for a proposal to sunset the Dynamic Line Ratings Task Force given the conclusion of much of the group's work.

Brian Fitzpatrick, PJM | © *RTO Insider LLC*

PJM's Natalie Tacka Furtaw *presented* two paths forward for the task force: putting it on hiatus and reconvening when needed, or sunsetting the group and issuing a new problem statement and issue charge should future issues arise.

The task force served an educational role for stakeholders, providing information on current rules from PJM and experience from transmission owners and technology vendors. (See "Dynamic Line Ratings," *PJM MRC/MC Briefs: April 27, 2022*.)

No new requests for information had been received by PJM since the task force's December meeting, leading to this month's meeting being canceled. Furtaw said Thursday's presentation is being considered a first read, and she will be returning to the OC next month for endorsement of sunsetting the task force. ■

— Devin Leith-Yessian

Company Briefs

Evergy Blames Renewables, Inflation for $1B Rise in Infrastructure Plans

Evergy last week said its infrastructure plan, which outlines investments in the grid and energy production, is more than $1 billion higher than the one it filed in 2021 because of inflation and plans to add more renewable energy.

It is the second consecutive year the company's investment plan was $1 billion more than the previous year. The new plan also estimates $1.2 billion more in spending compared to Evergy's "sustainability transformation plan."

Evergy, which serves 1.6 million customers in Kansas and Missouri, was called to testify before the Kansas Corporation Commission last month about the "highly concerning" jump in the cost of its capital investment plan. Commission staff were concerned the upward trend in expected spending "will undermine the goal of achieving regionally competitive rates and reliable electric service."

More: *Kansas Reflector*

Alabama Power Names Jeff Peoples as President, CEO

The Alabama Power Company last week announced that it has named Jeff Peoples as its president and CEO, as well as chairman of the board of directors, effective immediately.

Peoples joined Alabama Power in 1984 and most recently served as the company's executive vice president of customer and employee services.

Peoples will replace Mark Crosswhite, who retired after eight years.

More: *Alabama Power*

Leitner Named Tenaska CEO

Tenaska last week named Chris Leitner as its new CEO.

Leitner joined Tenaska in 2003. He most recently served as president of development and generation.

Jerry Crouse, who had served as CEO since July 2010, will take over as board chairman.

More: *Tenaska*

Csedrik Joins Balch & Bingham's DC Office

Balch & Bingham last week announced that Lewis Csedrik has joined the firm's Washington, D.C., office.

Lewis has more than 20 years of experience representing clients in the nuclear industry on work environment issues, investigations and enforcement matters, whistleblower litigation, and alternative dispute resolution before state and federal regulatory agencies.

Balch is recognized as a leading firm in nuclear regulatory and litigation cases.

More: *Balch & Bingham*

Federal Briefs

White House Does Not Support Gas Stove Ban

White House Press Secretary Karine Jean-Pierre last week said that the White House does not support a ban on new gas stoves and echoed earlier remarks from Consumer Product Safety Commission Chair Alexander Hoehn-Saric.

The comments come after CPSC Commissioner Richard Trumka Jr. last month said that a ban was on the table. As debate grew, Hoehn-Saric last week said that he is not seeking a ban.

Instead, the CPSC is expected to issue a formal request for "public input on hazards associated with gas stoves and proposed solutions to those hazards" by March.

More: *The Hill*

NOAA: US Hit by 18 Separate Climate Disasters Last Year

The United States was hit by 18 weather and climate disasters costing at least $1 billion each during 2022, according to a release from the National Oceanic and Atmospheric Administration.

The event amount tied with 2011 and 2017 for the third highest number of billion-dollar disasters in a calendar year, behind 2020 (22) and 2021 (20). The events killed at least 474 people and cost about $165 billion.

Events that cost at least $1 billion were nine severe weather or hail events, three tropical cyclones, two tornado outbreaks, one winter storm or cold-wave event, one wildfire event, one drought and heat-wave event and one flooding event.

More: *The Hill*

TVA to Replace Coal Plant with Natural Gas

The Tennessee Valley Authority last week announced it will replace its Cumberland coal plant with a natural gas facility.

The Cumberland plant is TVA's largest generator and consists of two coal-fired units. The first will be retired and replaced with a 1,450-MW combined cycle natural gas plant by 2026. The second unit will be retired by 2028 despite unknown replacement plans.

TVA said the switch to natural gas will require a new 32-mile natural gas pipeline across multiple counties and should cut the facility's carbon emissions by 60%.

More: *Knoxville News Sentinel*

Rodgers Named Chair of House Energy and Commerce Committee

Congresswoman **Cathy McMorris Rodgers** (R-WA) last week was named chair of the House Energy and Commerce Committee.

The Committee on Energy and Commerce, formed in 1795, is the oldest standing legislative committee in the U.S. House of Representatives and is

vested with the broadest jurisdiction of any congressional authorizing committee.

More: *Energy & Commerce*

Preliminary US Greenhouse Emissions Estimates for 2022 Show Small Rise

Based on preliminary economic activity and energy data, the Rhodium Group last week released a report that estimated that U.S. 2022 greenhouse gas emissions increased by 1.3% compared to 2021.

While carbon emissions grew in 2022, the 1.3% year-over-year growth was much smaller than the 6.2% rise in 2021. More significantly, emissions didn't rise as fast as overall economic output, indicating that the U.S. economy has become less carbon-intensive as it rebounds from the 2020 lockdowns. Carbon-free power generation grew 12% in 2022.

More: *Rhodium Group*, *The Grist*

State Briefs

ILLINOIS

Madigan Trail Date Set for April 2024

District Judge John Robert Blakey last week set a trial date of April 1, 2024, for former Illinois House Speaker Michael Madigan and a longtime confidant in relation to racketeering charges that allege they conspired to leverage Madigan's elected office and political power for personal gain.

Madigan, 80, and Michael McClain, 75, were charged in March 2022 in a 22-count indictment alleging they conspired to participate in an array of bribery and extortion schemes from 2011 to 2019, including an effort by Commonwealth Edison to pay off Madigan associates and win his support for legislation.

Both Madigan and McClain have pleaded not guilty.

More: *Chicago Tribune*

INDIANA

Invenergy Takes Solar Farm Dispute to URC

Invenergy has filed a complaint with the Utility Regulatory Commission to take one of two steps to allow for future construction of a $110 million solar project that will produce 120 MW in Madison County.

The company is asking the URC to rule that the county's solar ordinance is unreasonable or void. If that is not approved, the company wants the commission to provide an additional three years to complete the project. Invenergy officials claim that the litigation brought by remonstrators, and supply chain issues during the COVID-19 pandemic, made it impossible to construct the project by the end of this year.

A hearing is tentatively set for March 13.

More: *Tribune-Star*

MICHIGAN

IRS: DTE-affiliated Group Attempted to Repeal Whitmer's COVID Restrictions

IRS records from 2020 revealed that dark money nonprofit Michigan Energy First, which is linked to DTE Energy, funded a group that tried to repeal the emergency order powers of Michigan Gov. Gretchen Whitmer and end the state's COVID-19 lockdowns and restrictions.

IRS records revealing a $100,000 donation were not publicly available until late 2021 and show the funds were contributed to another dark money nonprofit — Michigan Citizens for Fiscal Responsibility — that served as a primary funder for the Unlock Michigan repeal campaign. Unlock Michigan was successful, as it complicated Whitmer's efforts to order restrictions and ended discussions of power shutoff moratoriums that included DTE. Michigan Energy First's three officers are DTE executives who work with an attorney, federal records show, and DTE executives have controlled the nonprofit since it was created in 2014.

DTE spokesman Peter Ternes said the company "unequivocally" did not make the donation.

More: *The Guardian*

NEBRASKA

New Bill Targets Renewable Energy

Sens. **Tom Brewer** and Steve Erdman recently co-sponsored a bill that would block Nebraska's largest electric utilities from building or acquiring renewable energy facilities or using eminent domain to do so.

The bill would forbid Nebraska Public Power District, Omaha Public Power District and Lincoln Electric System from applying to build solar or wind farms or plants that generate electricity with biomass, landfill or methane gas, hydropower, fuel cells or microturbines.

The bill would also block the utilities from pursuing "community-based energy development" projects meant to sell renewable energy to state utilities.

More: *Star-Herald*

Red Willow County Imposes Moratorium on Solar Plants

Red Willow County commissioners last week enacted a moratorium on alternative energy projects and approved a letter to the county planning and zoning commission asking it to consider size and capacity parameters of such projects in creating any new zoning regulations.

The moratorium is set for six months or the approval of new zoning regulations with the option to renew the moratorium.

More: *McCook Gazette*

TENNESSEE

TVA, NES Blame Frozen Sensors, Substation Fire for Rolling Blackouts

The Tennessee Valley Authority and Nashville Electric Service last week explained what went wrong and caused rolling blackouts during bitter cold temperatures over the holidays.

TVA said pressure sensors on two of its largest generators at its Cumberland City Fossil Plant froze in the sub-zero temperatures, tripping an automatic shutoff and cutting how much power they were able to produce, prompting the rolling blackouts.

NES said thousands more homes lost power because of a fire in a building at its Cane

Ridge substation involving rows of electrical communication equipment.

More: *WTVF*

TEXAS

RRC Investigates Atmos Energy for Failures During Freeze

The Railroad Commission is investigating gas distributor Atmos Energy for failing to supply its customers with natural gas during December's deep freeze.

Gov. **Greg Abbott** called on the commission to investigate the company after he said its failures left many residents without natural gas to heat their homes and without answers as to why. He asked the commission in a Dec. 28 letter to conclude its investigation "in a matter of weeks." As part of its investigation, the commission requested a list of items, including how many people were affected, what caused the low pressure, and a plan to address the issue in the future.

Atmos said that low pressure was the reason some customers experienced gas service issues, the commission said.

More: *Houston Chronicle*

VIRGINIA

Culpeper County Denies Maroon Solar for Third Time

The Culpeper County Planning Commission last week recommended denial of the 149-MW Maroon Solar project for the third time.

The size of the project, concerns about managing water at the site, and neighborhood impacts during construction emerged as the primary concerns.

The case now goes back before the Culpeper County Board of Supervisors for a final vote.

More: *Culpeper Star-Exponent*

Electric Bill Break for Big Users Crosses First Key Hurdle

The Commerce and Energy Committee last week voted 12-10 to recommend a bill that would give some of the state's biggest electricity users a break on their bills.

The bill, sponsored by Del. Lee Ware (R-Powhatan), sets up a pilot program that would exempt those companies from costs arising from Virginia utilities' obligation to cut carbon emissions. He said the bill includes protections for ratepayers, as there would be a limited five-year term for the break and it would be open to only a small number of the largest electricity users.

The bill now moves to the House of Delegates.

More: *Richmond Times-Dispatch*

Mecklenburg Rejects Boydton Area Solar Project

The Mecklenburg County Board of Supervisors last week unanimously voted to reject a utility-scale solar project proposed near Boydton.

The supervisors agreed with findings from the county planning commission that determined that the 90-MW facility did not conform with the county's comprehensive plan. They also agreed that the project would remove nearly 500 acres of prime farmland from agricultural use and potentially contaminate several creeks and Lake Gaston due to soil erosion.

More: *SoVaNow.com*