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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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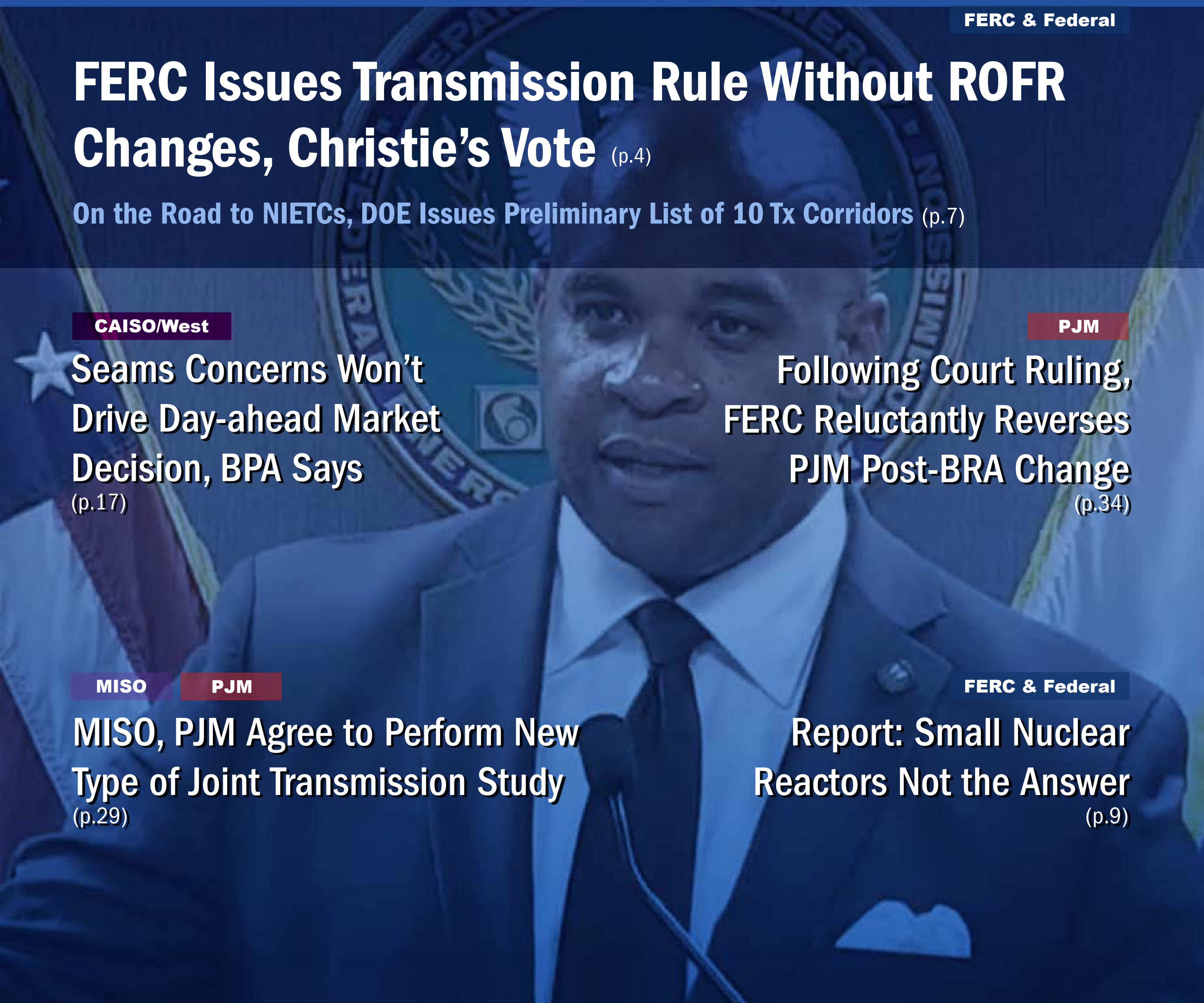

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RTO Insider
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In this week's issue

Stakeholder Soapbox

It's Time for New Wires on America's Grid

By Eric Gimon

An overlooked federal goal released alongside the Biden administration's new power plant emissions standards could have an outsized impact on our power grid.

The Department of Energy's goal of upgrading 100,000 miles of existing transmission lines by 2030 comes alongside utility claims that rising demand imperils grid reliability. An existing but underused technology — *reconductoring with advanced conductors* — can help utilities and grid operators overcome these problems.

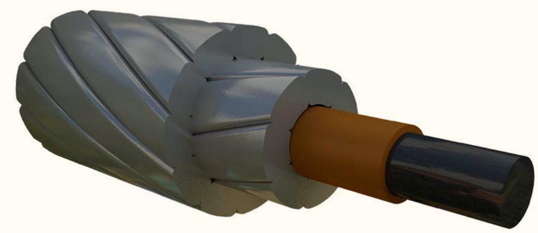
In 2005, Xcel Energy urgently needed to bring more energy into Minneapolis-St. Paul, but the constrained urban environment made building new transmission difficult. Existing transmission lines intersected two major highways, crossed residential and industrial zones, and passed through protected wetlands and a National Wildlife Refuge. Permitting new towers and wires risked delay, extra cost and potential failure.

Xcel instead decided to replace the existing line with higher-performance wire, increasing transmission capacity along the same route by using the same towers. This "reconductoring" wire replacement process greatly accelerated permitting. After eight weeks of construction, Xcel doubled the line's ampere rating.

New *research* from GridLab and the Goldman School of Public Policy at the University of California, Berkeley is the first estimate of potential clean generation deployment and cost savings that could be unlocked by reconductoring lines with advanced conductors. Replacing standard aluminum conductor steel-reinforced (ACSR) wires with advanced conductors can double a line's capacity within existing rights of way at typically less than half the price of new line for similar capacity increases.

Reconductoring is a pathway to spur nearly four times more interzonal transmission capacity expansion by 2035 compared to the average new-build transmission rate. This can help provide the majority of near-term interzonal transmission capacity needs to bring to market the 2,600 GW of cheap clean energy currently clogging interconnection queues.

Reconductoring can't meet all the needs of a low-cost clean energy system, but it can buy time to site and develop the new lines needed for long-term needs. Simultaneously reconductoring with advanced conductors and addressing barriers to new greenfield transmission provides the largest savings in total system costs of all considered scenarios: more than $400 billion by 2050 compared to business as usual.



| *Idaho National Laboratory*

The conclusion seems simple: Planning engineers and policymakers should find every place where cost-benefit analysis shows reconductoring with advanced conductor makes sense, then determine how to proceed. Unfortunately, nothing is simple when it comes to the bulk power system.

A companion *report* from Energy Innovation and GridLab identifies the barriers that have historically slowed use of advanced conductors and the policy recommendations to add advanced conductors onto the grid as quickly as possible.

Advanced reconductoring is stuck in the middle when it comes to cost recovery. Because it is a lower capital investment, monopoly utilities are instead incentivized to build entirely new lines. Advanced conductors also cost more than traditional wires, and regulators may view them as an unnecessary expenditure that gold-plates the system. A short-sighted, least-cost planning mindset for transmission owners makes it hard to accurately assess these benefits compared to either building new lines or using conventional conductors, so advanced conductors fall by the wayside.

New policies at the state and federal level can help ISO/RTOs get the most from this technology. State regulators and legislatures should proactively develop a policy position for advanced conductors, helping expedite planning at the state and ISO/RTO level. For example, RTOs lack the information to second-guess TOs' determinations that reconductoring with a traditional conductor or greenfield transmission could be done with advanced conductors. State policymakers can also support education and workforce training in reconductoring.

FERC's efforts to enhance regional planning processes can significantly improve resilience and integrate low-cost renewables through including advanced conductors. The rule approved by FERC on May 13 aims to modernize these processes by mandating forward-looking planning with a 20-year horizon, making the advantages of advanced conductors — increased transmission capacity and efficiency — more apparent in cost-benefit analyses. As regions update their compliance with this rule, especially in defining which benefits to weigh against costs, FERC can advocate for including conductor efficiency as a key factor in these evaluations.

Beyond recent rulemakings, FERC should also consider creating independent transmission monitors (ITMs). Many states lack substantial review over transmission planning; in California, for example, 63% of projects from 2019 to 2022 were self-approved as "repair and replacement" projects. Non-RTO regions are not required to produce data allowing stakeholders to study, expose and challenge incumbent utilities to explore reconductoring or other transmission expansion to benefit consumers. ITMs could add data transparency and transmission planning expertise capacity for states and regions to objectively evaluate transmission projects and ensure TOs consider projects that add significant value to customers at lower cost, like reconductoring with advanced conductors.

America's grid needs new wires. Advanced reconductoring is ready. Now it's time to implement the technology. ■

Eric Gimon is a senior fellow with Energy Innovation.

FERC/Federal News

FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote

Christie Dissents over Lack of State Say over Cost Allocation

By James Downing

FERC Chair Willie Phillips takes questions from reporters after the commission approved Orders 1920 and 1977. | *FERC*

FERC issued Order 1920, its long-awaited final rule on long-term regional transmission planning and cost allocation, during a special meeting May 13, but it could not fulfill hopes for a unanimous vote (*RM21-17*).

The order requires regional transmission planners, including ISOs and RTOs, to plan at least 20 years ahead of time using multiple scenarios while taking into consideration seven benefits:

- avoided or deferred reliability transmission facilities and aging infrastructure replacement;
- reduced loss-of-load probability or lower planning reserve margins;
- production cost savings;
- lower line losses;
- lower congestion from transmission outages;
- mitigation of extreme weather events and unexpected system conditions; and
- capacity cost benefits from reduced peak energy losses.

Planners will have to give state entities six months to agree on a cost-allocation method, but they also have to propose a default method. They can decide to push through their default method and will not be required to file any alternative states come up with.

That ability to override state desires — plus the end of the separate consideration of economic, reliability and public policy lines — led to Commissioner Mark Christie dissenting on the entire order, while Chair Willie Phillips and Commissioner Allison Clements filed a joint concurrence.

"Not everybody is going to get everything that they want," Phillips said during the meeting. "I don't even get everything that I want, but that is the nature of these large proceedings and these large rules here at FERC. This rule cannot come fast enough. There is an urgent need to act to ensure the reliability and affordability of our grid. We are at a transformational moment for the electric grid with phenomenal load growth from a domestic manufacturing boom, unprecedented construction of data centers fueling an AI evolution, and ever-expanding electrification."

The resource mix is at an inflection point with aging infrastructure needing replacement, and a higher incidence of extreme weather has cost consumers billions of dollars over the past decade, he added. Transmission expansion has not kept pace with the changes, falling to an all-time low in 2022, and much of that was "Band-Aid" fixes, Phillips said.

Christie said the Notice of Proposed Rulemaking was a bipartisan deal, but that bipartisanship did not carry forward into the final rule. (See *FERC Issues 1st Proposal out of Transmission Proceeding*.)

In addition to ending public policy as a separate consideration, Christie also criticized the final rule's requirement that planners consider demand from large corporate customers favoring specific generation types to serve their operations.

"If we're going to mix reliability projects with public policy projects, and these corporate-driven, preferred purchasing projects, then it's only fair that state regulators have to have the ability to consent to the planning criteria, and especially the cost allocation in a big, big multistate RTO, like PJM," Christie said in an interview. "That is absolutely essential. So that's not in there now. There's no requirement that states have to consent."

The NOPR did not spell out what would happen if states cannot come to an agreement, instead asking for comment on the issue. Clements told reporters that the decision to have a federal backstop made sense based on the record.

"We need to have a federally jurisdictional backup if the states don't come to agreement, and that is why we have a backstop *ex ante* approach," Clements said. "States don't have to use it; if they get together in a region and want to do something different — great."

The point where state regulators and an RTO

FERC/Federal News

might split on cost allocation is not going to occur until after the rule is implemented, she said. "But I wouldn't suggest it's a wise approach," Clements said of regional planners overriding states. "I think transmission providers want this to work as well and are looking forward to working with the states."

Christie questioned why the majority even voted to let regional planners, including ISO/RTOs and groups of utilities outside them, override state cost-allocation preferences.

"If you don't think they'd ever do it, then why wouldn't you agree to give the states the ability to consent?" Christie said. "Because the fact is, they can ignore it."

Phillips noted that he and Christie knew each other as members of the Mid-Atlantic Conference of Regulatory Utilities Commissioners before they came to FERC. He said he would never support a rule that tramples states' rights in the planning process.

"There's a lot that Commissioner Christie said that I simply do not agree with," Phillips said. "But I do agree with this: The most important job of our commission is reliability. I've been saying that since Day 1. So let me be clear now, because this rule is about reliability and affordability: I have complete confidence that it will be legally durable and that it will be upheld."

Another area where the three commissioners could not agree is whether the rule is reacting to the industry's realities or actively seeking to drive the grid toward a preferred future.

"It is not our job to do resource planning," Clements told reporters. "States, private actors — they engage in choosing what kind of resources they want to have. It is the commission's job to facilitate reliability and affordability of the transmission system in light of the choices that states and other actors are making outside of the agency."

Christie argued that the rule was being pushed out along with other policies the Biden administration favors. He noted in his dissent that he quotes several press reports linking the transmission rule to efforts to combat climate change.

"What this is doing here is attempting to enact a major policy agenda that has never been passed by Congress," Christie said. "And that alone makes it a major question. So, it's a very important point in my dissent that this is not within the authority of FERC under the Federal Power Act."

The order will go into effect 60 days after its publication in the *Federal Register*. Transmission providers will be required to submit compliance plans for most of the order's requirements within 10 months of the effective date.

FERC Pulls Back on ROFR Rollback

One aspect of the NOPR that drew considerable debate was the proposed partial rollback of Order 1000's elimination of most federal rights of first refusal, which opened regionally planned lines to competition. The commission had proposed establishing a conditional ROFR when a utility works with a partner on a project.

The change was a major priority for utilities and their trade groups, including the Edison Electric Institute and WIRES Group, but it was opposed by competitive transmission developers, consumer groups and the Federal Trade Commission.

The commission required transmission providers to identify opportunities to modify in-kind replacement of existing facilities to increase their transfer capability, known as "right-sizing." Utilities will get to keep a federal ROFR over such right-sized projects that are in their territories.

Order 1977 on Backstop Transmission Siting

FERC also issued Order 1977, which implements its new congressionally mandated authority to site transmission lines in a National Interest Electricity Transmission Corridor even when state regulators reject them (*RM22-7*). All three commissioners supported this order.

The order "includes a Landowner Bill of Rights, codifies an Applicant Code of Conduct as one way for applicants to demonstrate good-faith efforts to engage with landowners in the permitting process, and directs applicants to develop engagement plans for outreach to environmental justice communities and tribes," FERC said.

The one major change from the proposal was that FERC will not let transmission developers file for its siting approval at the same time as a state is reviewing a line. They will instead have to wait a year.

Many states argued that allowing transmission developers to file at FERC while also pursuing a state certificate would effectively usurp their authority. (See *FERC Backstop Siting Proposal Runs into Opposition from States*.)

The order will take effect 60 days after its publication in the *Federal Register*.

Initial Takes

Senate Majority Leader Chuck Schumer (D-N.Y.) held a press conference call while FERC was still meeting to praise the final rule.

"The clean energy incentives included in the Inflation Reduction Act have been a huge success," Schumer said. "But much of that success would be lost without the ability to bring power from places that generate renewable energy to communities all across the country. A new historic advancement in our transmission policies has been desperately needed, and the rules released by FERC today will go a long way, a very long way to solving that problem. Simply put, these new rules will mean more low-cost, reliable, clean energy for the places that need it most."

Many proposed bills have been introduced this Congress to address transmission and other permitting issues, with Senate Energy and Natural Resources Committee Chair Joe Manchin (D-W.Va.) and Ranking Member John Barrasso (R-Wyo.) trying to get a deal through to simplify building infrastructure. Schumer said such efforts will be hard to get past a divided Congress this year.

"I've told Joe Manchin it's going to be virtually impossible to get something done," he said.

For his part, Barrasso blasted "FERC's partisan vote," arguing it would only add to electricity's growing costs.

"Today's decision will force customers — often in rural states — to pay for new transmission lines even when those lines don't provide any meaningful benefit to them," Barrasso said. "It is the Holy Grail for liberal politicians in California and New York and corporate executives who want others to foot the bill for their climate obsession. I have no doubt the cost of energy will be at the top of every voter's mind later this year."

House Democrats welcomed the final rule, with Reps. Sean Casten (D-Ill.) and Mike Levin (D-Calif.), co-chairs of the Sustainable Energy and Environment Coalition's Clean Energy Deployment Task Force, calling it a vital step toward a fully clean economy. Despite Schumer's doubts, they said they would like to pass additional legislation on transmission — especially their own *Clean Electricity Transmission Acceleration Act*.

"This rule takes steps towards ensuring our grid is meaningfully planned and the costs of the necessary transmission buildout are fairly distributed by those who will benefit from the new capacity," they said in a joint statement. "Americans today are already bearing the costs of an improperly planned grid; transmission planners have thus far not adequately accounted for the new forms of cheap, clean energy that are being deployed on the grid at an accelerating pace. A reliable, affordable and clean grid is only achievable with proper, comprehensive and forward-looking grid planning."

Americans for a Clean Energy Grid praised the rule, saying it ensures the grid will be planned in a proactive and comprehensive way.

"Now, it's time to implement this rule," ACEG Executive Director Christina Hayes said. "Regions must develop their compliance filings over the next few months so that transmission can be planned and developed as soon as practicable. We look forward to working with and supporting the interested parties as they move forward with the next steps in compliance and build out the 21st-century grid."

Advanced Energy United welcomed the rule, saying it would help lower consumer bills by making a more efficient grid and opening access to cheap power.

"Families and businesses are paying the price for utilities' and grid operators' failure to address our critical electricity infrastructure needs," CEO Heather O'Neill said in a statement. "Building more multistate transmission lines unclogs the traffic jams on America's electricity superhighways and unlocks our ability to keep up with our growing energy needs. This FERC order sends the message that transmission planning needs to change and recognizes that states deserve a central role in ensuring a reliable electric grid built for the future."

EEI was not as enamored as the clean energy trade groups, citing disappointment with the decision not to roll back Order 1000's ROFR provisions, among other issues.

"Additionally, the failure to provide regional flexibilities for evaluating project benefits in the final rule will lead to longer compliance processes and, ultimately, could slow the development of much needed transmission projects," EEI Vice President of Regulatory Affairs Phil Moeller said in a statement. "A one-size-fits-all approach does not work, as different regions have different needs and different states have different policies."

Environmental groups generally praised the final rule, with Sierra Club Executive Director Ben Jealous saying it "follows the letter of the law" and will save ratepayers money.

"As President Biden's Inflation Reduction Act continues to usher in the clean energy future through deployment of solar, wind and battery storage, this transmission standard will allow utilities to deliver Americans clean, affordable electricity, even in the face of rising demand and extreme weather caused by climate change," Jealous said in a statement. "With the standard now in place, FERC must be vigilant to ensure strong implementation in order to maximize the benefits for reliability and consumers." ■

K Kaufmann contributed to this report

FERC/Federal News

On the Road to NIETCs, DOE Issues Preliminary List of 10 Tx Corridors

DOE Process for NIETC Designation will not be Affected by FERC Tx Planning Rule

By K Kaufmann

The U.S. Department of Energy is looking to boost interregional transmission with its announcement May 8 of 10 proposed National Interest Electric Transmission Corridors (NIETCs), where projects could be eligible for a share of $2 billion in federal loans and special permitting under FERC's backstop permitting authority.

DOE defines a NIETC as a geographic area where "it is determined that consumers are harmed, now or in the future, by a lack of transmission in the area and the development of new transmission would advance important national interests for that region, such as increased reliability and reduced consumer costs."

The list was compiled based on DOE's *2023 National Transmission Needs Study* and public input, according to a senior DOE official speaking on background during a May 7 media briefing. Issued in October, the study specifically identified potential interregional transmission needs across the country. (See *DOE Signs up as Off-taker for 3 Transmission Projects*.)

But beyond those findings, the department looked at "factors such as reliability, resilience, congestion, very importantly consumer costs and future generation demand growth, which is a very important issue right now," the official said. "And for some of these also, we're looking at what ultimately unlocks clean energy and allows for clean energy resources to interconnect to the grid."

Energy Secretary Jennifer Granholm said the preliminary list includes areas that "are high priority for more transmission buildout. … This program is going to help us build out transmission capacity quickly and efficiently for the people who need it most without compromising on the quality of environmental reviews or community outreach."

The list includes corridors as narrow as 0.3 miles across and as wide as 345 miles east to west, for example:

- the New York-New Jersey corridor, 4 miles wide and 12 miles long, providing an

DOE has proposed 10 potential NIETCs, with a special focus on increasing capacity for interregional transfers of power between the Eastern and Western interconnections. | *DOE*

FERC/Federal News

interregional connection between PJM and NYISO, as well as interconnection points for offshore wind projects;

- the Plains Southwest corridor, running 345 miles east to west and 220 miles north to south, covering portions of Kansas, New Mexico, Oklahoma and Texas; and
- the Mountain-Northwest corridor, 0.3 miles wide and 515 miles long, running from Oregon to Nevada.

Some corridors also stretch over multiple parallel or adjacent sections, such as the Mid-Atlantic corridor, covering parts of Maryland, Pennsylvania, Virginia and West Virginia with parallel lines 2 miles across and up to 180 miles long.

These and the other corridors on the list all have one or more potential transmission projects under development, which a NIETC designation could help accelerate, according to the DOE announcement.

Other considerations include co-location with an existing highway or transmission right-of-way, and the potential to get more renewable energy online and increase transmission capacity between the Eastern and Western interconnections. The longest potential NIETC, the Midwest-Plains corridor, runs 780 miles, beginning in Kansas, crossing Missouri and Illinois and ending in Indiana.

The proposed corridors on the list could be reconfigured through further public and industry input, DOE officials said. But projects located within any NIETC corridor are eligible for federal loans drawn from a $2 billion fund set up by the Inflation Reduction Act.

NIETC projects could also be eligible for permitting through FERC's backstop authority, established in the Infrastructure Investment and Jobs Act, allowing the commission to permit projects in a corridor if state regulators don't have permitting authority or have delayed project approvals.

FERC has yet to decide if and how it might use the backstop permitting option, but the issue is on the commission's agenda for May 13, when it is expected to vote on its long-awaited transmission planning and cost allocation rule.

The senior DOE official stressed that the NIETC designation process is separate from any FERC decision on its backstop permitting authority but said the backstop authority can only be used for a project in a NIETC.

'A Few Backyards'

The NIETC announcement was the latest in a string of initiatives DOE has rolled out in recent weeks expanding transmission capacity across the country and streamlining the permitting process. On April 25, DOE launched its Coordinated Interagency Authorizations and Permits (CITAP) program, which is intended to cut environmental permitting time for transmission projects to two years.

DOE is also standing up artificial intelligence tools to streamline and accelerate permitting for transmission and other clean energy projects, announced April 29. (See *DOE: AI Critical to US Clean Energy, Grid Modernization Goals*.)

Even more strategically, the release of the preliminary NIETC list comes less than a week before FERC is scheduled to vote on its long-awaited transmission planning rule, which administration officials again stressed is separate from the NIETC program, which may not be directly affected by the decision.

"We're looking forward to a rule that will … give people certainty and stronger tools to make sure these projects get built," John Podesta, White House senior adviser on international climate policy, said at the May 7 briefing. "[FERC] will at the end of the day render their judgment about how far to go in that regard, but I think it's another important step to ensure we have the ability to cut through the red tape."

The need for an acceleration of transmission planning and permitting remains pressing. About 2.6 GW of projects, mostly solar, wind and energy storage, are sitting in RTO and ISO interconnection queues across the country, according to Lawrence Berkeley National Laboratory's 2024 *Queued Up* report.

To meet President Joe Biden's 100% clean power goals by 2035, "we need to more than double our current transmission capacity," Podesta said. "The truth is, if we can't build critical clean energy projects through a few backyards, then no one will have a backyard."

The May 8 announcement marks the beginning of the second of four phases of NIETC designation as outlined in the *guidelines* DOE issued in December. In the first phase, which ran from mid-December to early February, DOE gathered input from stakeholders.

The release of the preliminary list kicks off a 45-day comment period, which will run through June 24. Phases 3 and 4 will include a due diligence process and environmental reviews under the National Environmental Policy Act, which could take up to two years.

DOE has yet to state how many NIETCs may be on the final list or when it will be released. ■

FERC/Federal News

Report: Small Nuclear Reactors not the Answer

Researcher Says SMR Proponents Overly Optimistic

By Holden Mann

Squassoni said Russia's Akademik Lomonosov, a barge housing two small nuclear reactors, is one of only two currently operating commercial reactors that could be considered SMRs. | *Elena Dider, CC BY-SA 4.0, via Wikimedia Commons*

In a recent report, a nuclear power expert from George Washington University strongly criticized proponents of nuclear power for presenting what she considered an overly rosy picture of the technology's potential to meet the world's energy needs while ignoring its many reliability and security challenges.

The author of "*New Nuclear Energy: Assessing the National Security Risks*," Sharon Squassoni, is a research professor of international affairs at GWU whose work focuses on reducing risks from nuclear energy and weapons. In a webinar last month, Squassoni said her goal in writing the report was to explore "what risks might arise given the goals of tripling nuclear energy and deploying small modular reactors to do many things in many places."

With increasing awareness of the climate effects of burning fossil fuels, some energy experts have touted nuclear energy as a proven technology for meeting baseload energy needs without emitting carbon dioxide and other pollutants. SMRs have emerged as the centerpiece of "an effort to make nuclear energy more affordable, safe and flexible, and thus more attractive to a broader range of uses and users," the report said.

However, the document pointed out that despite much effort from the nuclear industry and governments "to make nuclear energy relevant again after decades of stagnation," the actual presence of SMRs on grids "is largely fictional."

While nuclear boosters have held out visions of cheaply built, moveable reactors powering individual towns and military installations while providing numerous other services, Squassoni said there are currently only two operating facilities that actually merit the SMR label. These reactors — China's *HTR-PM plant*, in operation since December 2023, and Russia's "floating nuclear power plant" *Akademik Lomonosov*, launched in 2010 — solve few of traditional nuclear plants' problems and may create new ones, according to the report.

The HTR-PM uses two reactors with a capacity of 100 MWe each, using a "pebble-bed" design incorporating spherical balls of uranium enriched to 8.5% U-235 (compared to the 3 to 5% enrichment *typically used* in commercial U.S. reactors). It was launched in 2001, based on an existing test reactor, with on-site construction beginning in 2012.

The report noted that the higher enrichment of the reactor's fuel could make it more attractive for use in a nuclear weapon, while the fuel fabrication, storage of spent fuel and reprocessing "will be more challenging to monitor" than in current reactors. In addition, safeguarding the reactor could be more challenging because it uses on-line refueling, a more complicated process than shutting down the reactor first, and because the spent fuel is stored on site.

Akademik Lomonosov comprises two reactors with a capacity of 35 MWe each and was intended to replace a retired nuclear plant and coal plant in the Chukotka region of eastern Russia. The report noted that placing nuclear plants on a barge does solve the issues of "scarce land for nuclear power plants that require large emergency planning zones," but the design is far from flawless. Planners must consider the risks of shipping collisions and tsunamis, along with the potential environmental damage of fuel and waste leaks.

Floating plants are also "open to attack either from the surface of the sea or beneath it," the report said. Pirates and terrorist groups could infiltrate the facilities to steal radioactive material or threaten to damage the plants for financial or political gain.

Additionally, the report warned that "SMRs are unlikely to be built in quantities that will revolutionize nuclear energy" because focusing on large amounts of small reactors means giving up the economies of scale that come with building a single large, centralized plant. The report cited analysis from Princeton University suggesting "700 [small] plants would need to be produced" to outweigh the benefits of large plants, noting that "this is roughly the total number of commercial nuclear … reactors ever built."

Side Benefits Slow to Emerge

SMR supporters have also proposed that small reactors could provide additional benefits besides electricity, such as residential and industrial heating, desalination, and hydrogen production. The report said that these uses are "neither new nor unique to nuclear energy," and Squassoni suggested that they would likely not be mentioned if alternatives to nuclear generation for electricity had not recently become available.

FERC/Federal News

"In the past, maybe 10 to 15 years ago, the nuclear power narrative was that nuclear was the only low-carbon baseload generation," Squassoni said during the webinar. "But what's happened in the interim is that [renewable energy sources] have captured such a huge part of the market for electricity generation that nuclear now has to tout its ability to multitask."

This multitasking ability has been touted by the U.S. Department of Energy, and the Electric Power Research Institute floated its *NuIDEA* plan last year that would see multiple microreactors operate at airports, college campuses, hospitals and other facilities to provide a range of services. But the GWU report said efforts to realize these ambitions will "likely be an uphill climb," noting that in the U.S., only the *Diablo Canyon* reactor in California has provided desalination, and none has ever provided district heating.

"Although there are more than 660 district energy systems operating in the United States, few present the right economics for large nuclear cogeneration plants," the report said. "Smaller plants sprinkled among population centers might overcome the costs of heat transportation, but technical issues like the availability of large dual-purpose turbines to produce electricity and extract steam at suitable temperatures and pressures may continue to persist."

Military Risks Growing

Finally, the report warned about the possibility for SMRs to become military targets.

Russian forces have occupied both the Chernobyl and Zaporizhzhia power plants at different times since they invaded in 2022 and remain in control of Zaporizhzhia as of early May. The head of the International Atomic Energy Agency (IAEA) *recently said* that Russia's "reckless attacks" have brought the danger of nuclear mishaps "dangerously close." Such an event would have devastating consequences not only for grid reliability but also for the local environment.

"Cooperation among key states essential to minimize the safety, security and proliferation risks of nuclear energy is at an all-time low," the report said. "The call to triple nuclear energy coincides with the disintegration of cooperation, the unraveling of norms and the loss of credibility of international institutions that are crucial to the safe and secure operation of nuclear power."

The report called for the U.S., Russia and China to resume their cooperation in nuclear nonproliferation rather than allowing the current environment to spiral into "great power competition."

"The United States still wields considerable influence in international fora associated with nuclear energy, nonproliferation and nuclear security, and it should use this influence to ensure that any expansion of nuclear energy does not exacerbate national security risks," the report said. "But first, it will need to get its own policy house in order."

Pushback from Nuclear Community

Several nuclear experts who spoke to *RTO Insider* criticized the report, saying it overstated the risks of SMRs without considering the efforts of the international community to address them.

Madeline Lockhart, a doctoral fellow in nuclear engineering at North Carolina State University, acknowledged that growing the nuclear fleet "will naturally lead to an increase in the associated nuclear security risks." But she argued that the report's characterization of these dangers is "not well defined," and that policies should address the risks connected to "specific capabilities, facilities, designs, locations and countries" rather than taking an overly broad view.

"Government organizations, National Laboratories and stakeholders are actively engaged with reactor vendors and buyers to address and minimize national security risks before any reactor will be connected to the grid. Often, robust and complex regulations and guidelines contribute to the extended timelines for reactor deployment — but the goal is always the deployment of safe and reliable energy production," Lockhart said. "While the national security risks must be addressed, the risk associated with the failure to meet a growing global demand for electricity will be devastating."

Mehdi Sarram, who served as safeguards director of the Atomic Energy Organization of Iran from 1974 to 1979 and later served in DOE and the IAEA, called the report "biased toward a negative view of nuclear energy." He disputed Squassoni's claim about the vulnerability of Chernobyl and Zaporizhzhia, saying that the IAEA "has worked with Russia to avoid a possible attack on Ukrainian nuclear plants."

The report also discounts the boost that technological advances bring to nonproliferation work, according to Angela Di Fulvio, associate professor of nuclear, plasma and radiological engineering at the University of Illinois Urbana-Champaign. Di Fulvio noted that advances in radiation detection systems and other technologies helped the IAEA track the development of China's nuclear weapons capabilities.

With regard to SMRs, Di Fulvio admitted that deploying such resources may require "a paradigm shift in material accountancy" and close collaboration between designers and the IAEA to develop proper safeguards against diversion of nuclear material, particularly in regions of political instability. But she insisted that these risks "can be mitigated effectively" and should not prevent the deployment of needed energy resources.

Paul Dickman, chair of the American Nuclear Society's External Affairs Committee and formerly with DOE's National Nuclear Security Administration, focused on the challenge of building large fleets of SMRs, noting that the U.S. lacks manufacturing capacity to produce reactor components on a large scale. He said that rather than looking to SMRs to replace large plants as baseload energy suppliers, they should be used to "fill in gaps where grids are small or to replace smaller coal and oil-based generating stations." ■

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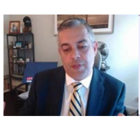

NERC Expecting Tight Summer Conditions — ERO Insider

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FERC/Federal News

Republican-led States Sue EPA over Power Plant Emissions Rule

By K Kaufmann

Republican state attorneys general sued EPA on May 9 seeking to stop implementation of the agency's final rule aimed at slashing greenhouse gas emissions from existing coal plants and new natural gas plants.

Under the rule released April 25, existing coal-fired power plants nationwide will have to either close by 2039 or use carbon capture and storage or other technologies to capture 90% of their emissions by 2032. New natural gas plants will have until 2035 to similarly cut their emissions, through efficient design, carbon capture or a combination of both. (See *EPA Power Plant Rules Squeeze Coal Plants; Existing Natural Gas Plants Exempt*.)

The suit, filed with the D.C. Circuit Court of Appeals, is led by Indiana Attorney General Todd Rokita and West Virginia Attorney General Patrick Morrisey, the latter of whom led states' successful lawsuit against the Obama administration's Clean Power Plan. (See *Supreme Court Rejects EPA Generation Shifting*.)

"The EPA continues to not fully understand the direction from the Supreme Court; unelected bureaucrats continue their pursuit to legislate rather than rely on elected members of Congress for guidance," Morrisey said in a *statement*. "We are confident we will once again prevail in court against this rogue agency."

The National Rural Electric Cooperative Association filed its own suit against the rule with the D.C. Circuit the same day.

"EPA's power plant rule is unlawful, unreasonable and unachievable. It exceeds EPA's authority and poses an immediate threat to the American electric grid," CEO Jim Matheson said. "Reliable electricity is the foundation of the American economy. EPA's rule recklessly undermines that foundation by forcing the premature closure of power plants that are critical to keeping the lights on — especially as America increasingly relies on electricity to power the economy."

Both suits are essentially placeholders, petitioning the court for judicial review and attaching the rule as evidence but making no arguments. They were filed a day after a *separate suit* — led by Morrisey and North Dakota Attorney General Drew Wrigley, and joined by 21 other Republican-led states — was filed with the D.C. Circuit challenging EPA's updated implementation of the Mercury and Air Toxics Standards, announced by Administrator Michael Regan at the same time as the power plant rule.

"The Biden administration pushes a green political agenda with no purpose other than to attack fossil fuels. Make no mistake, this rule intentionally sets impossible standards to destroy the coal industry," Wrigley said in a *statement*. "Federal agencies cannot decide on a whim to destroy entire industries. They are only permitted to work within the bounds that Congress set for them."

EPA declined to comment on the pending litigation. ■

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Brattle Report Details Impact of 'Lumpy' Loads on Utility Forecasts

By James Downing

New sources of demand growth such as data centers for artificial intelligence and rising industries are complicating electricity load forecasting, according to a new report released by The Brattle Group on May 8.

Electricity Demand Growth and Forecasting in a Time of Change provides an overview of several new demand drivers that will affect load growth and patterns in the coming decades and how utilities include them in their forecasts.

"Currently, there is a wide spectrum among utilities in how they account for these new drivers," T. Bruce Tsuchida, a Brattle principal and co-author of the report, said in a statement. "The future net load growth spurred by the new drivers is vast, and our analyses suggest that — given this growth, along with the change in load characteristics and other associated uncertainties — the industry will require a revamped approach to load forecasting moving forward."

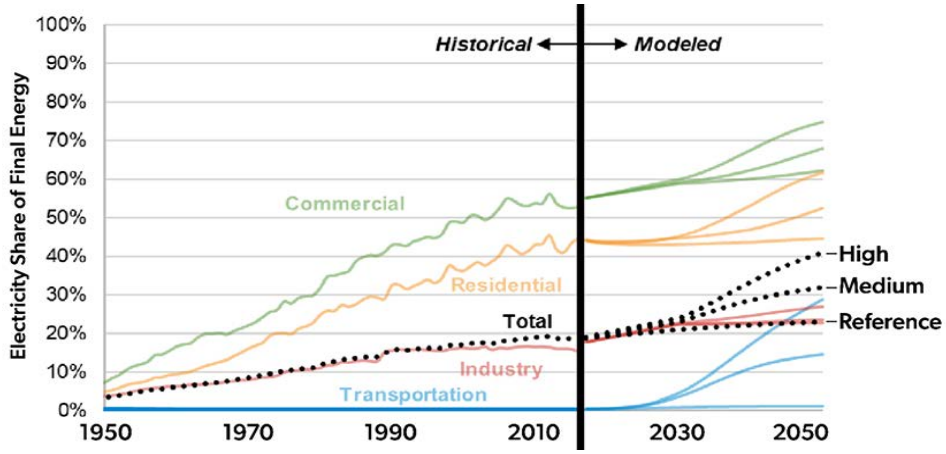
NERC recently raised its compound annual growth rate (CAGR) for load from 0.6% per year to 1.1% per year over the next 10 years, which is higher than at any point in the past decade. FERC Form 714 filings from utilities have shown peak demand growth rates increasing from 2.6% in 2022 to 4.7% in last year's filings, Brattle's report said.

The new demand drivers and their changing nature and flexibility warrant looking at load forecasting from a different perspective, it said.

"In today's world, where much of these new demand drivers are policy-driven, the risk of under- versus over-forecasting is asymmetric," the report said. "With a climate strategy that relies heavily on clean electrification, the cost and long-lasting effects of underforecasting may be much larger than those of overforecasting — while still recognizing that large overforecasts also have accompanying costs."

Policies aimed at combating global warming are driving some of the new demand, but in some regions, new data centers are having a major impact on load growth. Data centers use about 19 GW of capacity now, but with a 9% CAGR, the sector is expected to add the equivalent of New York City's demand over the next five years nationally.

"The number of data centers is growing rapidly to meet increasing data usage from streaming services, social media, mobile devices and cloud computing, just to name a few," the report said. "The emerging fields of AI and machine learning require massive computational power and storage, fueling demand for data center infrastructure and, with it, the demand for electricity. These loads tend to run constantly."



A chart from the Brattle Group's report showing historical and projected share of energy that electricity serves by sector. | *The Brattle Group*

Cryptocurrency mining uses an estimated 10 GW to 17 GW across the country, and its growth is volatile and based on crypto prices, but it could grow by an additional 8 GW to 15 GW by 2030.

Type A vs. Type B

However, the biggest potential source for growth this decade, Brattle reports, is hydrogen production, which could increase from just 70 MW to 25 GW of demand by 2030, which works out to 132% growth yearly.

The load growth drivers can be classified in two basic ways: "Type A" loads that are large and discrete and often characterized by more uncertainty, and "Type B" loads that are comparatively smaller with smoother growth patterns.

Load growth from electrifying transportation and buildings counts as Type B, but the industry still faces significant uncertainty around its long-term trajectory.

"Load growth from electrification, which naturally requires replacing existing stocks, takes time to materialize and is usually geographically uneven," the report said. "This contributes to higher levels of uncertainty in these forecasts."

Data centers, new industry, indoor agriculture and cryptocurrency mining are Type A. "These loads are often quite large and lumpy (sometimes as large as an entire city)," the report said. Their expansion is also concentrated in specific areas and their development can move faster than utility or ISO/RTO planning processes.

The new loads can change suddenly due to shifts in the market or policy and in some cases — such as with cryptomining and indoor agriculture — they can disappear without notice.

"Some of these loads may be able to provide flexibility, so the conventional assumption that planning requires building enough capacity to serve an inflexible peak load may no longer be true," the report said.

Even without local flexibility, efficiency, demand response and distributed energy resources can offset potential load or sales growth. Those demand-side resources can be large and cost effective for freeing up supply increments for high-priority uses.

Brattle collected load forecasting documents from utilities and ISO/RTOs around the country for the report and found a spectrum of ways entities are dealing with the new drivers of demand. Traditional load forecasting methods assumed that new demand would be inelastic and that future needs could be addressed within a long planning horizon, usually measured in years.

"One of the first steps planners could take today is to comprehensively assess the various drivers, even if a sophisticated modeling approach is not yet available," the report said. "The latter should come next after the new load types are better understood." ■

FERC/Federal News

AEU: Electrifying MHD Vehicles Could Lower Grid Costs

By James Downing

Serving new demand from medium- and heavy-duty vehicle (MHDV) electrification will require some grid upgrades, but it could lower utility rates overall, Advanced Energy United said in a *paper* published May 6.

Impacts at the substation and feeder level will vary by where fleets of electric MHDVs might charge and how much headroom exists on the distribution system. That will require careful estimation and planning as fleets electrify, the report says.

"Greater MHDV electrification will result in greater electricity sales, increasing utility revenues," the report says. "As long as the increased utility revenue from [electric vehicle] charging exceeds increases in utility system costs, transportation electrification will benefit all electric utility ratepayers by putting downward pressure on rates."

That might not mean lower rates overall because other factors could drive them up, Richard Khoe, program supervisor at the California Public Utilities Commission's Public Advocates Office, said on a webinar held by United on May 7.

His office did a similar study for California, which estimated a total of $26 billion to upgrade the distribution grid for the electrification of light-duty vehicles, MHDVs and homes, compared to a $50 billion estimate from a different report conducted for the PUC.

"We also found that the downward pressure on rates might not be achieved if any of the following things were to occur," Khoe said. "For example, if EVs mostly charged in the evenings near peak hours, that would drive peak load up … and that would lead to higher upgrade costs."

Using electric rates to subsidize charging excessively — or the study's upgrade cost estimates being too low — could lead to higher rates, he added.

"We found that on a systemwide basis, peak loads probably are only going to increase by about 1 to 2% ... by 2035," said United report co-author Sarah Shenstone-Harris, of Synapse Energy Economics. "So not all that much. But at the feeder and substation level, the impact is much more varied."

The main issue with MHDV electrification is that vehicles are likely to be clustered at specific sites, such as a warehouse district with panel trucks, or a bus depot, Shenstone-Harris said on the webinar. Some of those areas might have enough headroom to accommodate charging, but others will require upgrades.

"Generally, studies haave found that loads of 1 to 5 MW will require a new feeder, or an upgrade, and loads of 5 to 10 MW will require a new substation or a substation upgrade," Shenstone-Harris said. "But again, it really depends on the specifics. And as you can imagine, cost ranges also vary a lot depending on the specifics of the project, as well as lead time."

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United's report offers four recommendations for states to get it right:

- require utilities to share data about capacity of the distribution grid;
- improve utility planning and regulatory processes to address barriers to electrification;
- implement programs to manage peak loads and minimize costs; and
- target certain areas for grid investment and/or MHDV adoption.

"A state or utility that doesn't adopt these kinds of recommendations [is] surely going to be confronted with painful challenges down the road," the New York Department of Public Service's Zeryai Hagos said. "And this is because the four recommendations will work in unison to avoid long delays in interconnection — delays that could last for several years."

A study in New York found that MHDV make-ready programs, which cover the upgrade costs of electrification, have a neutral to beneficial impact on rates through 2045, the report says. Benefits grew when charging was shifted to off-peak hours.

MHDVs can also serve as batteries in vehicle-to-grid services, contributing to grid stability and supporting the integration of renewable energy sources. Possessing larger batteries than standard cars, MHDVs can charge with more renewable energy when it is producing a surplus and can offer bigger discharges when the grid is stressed.

EVs cost more upfront than standard models, but they benefit from major fuel and maintenance savings over their lifetime. An electric delivery truck can save 34% compared to a diesel model over its lifetime, while an electric bus could save 24%.

"Electric vehicles have fewer moving parts and simpler drivetrains compared to internal combustion engines, leading to substantially lower maintenance needs," the report says. "Plus, with EVs' regenerative braking technology, certain pieces of braking equipment need to be replaced less frequently." ■

FERC/Federal News

ASE: Energy Transition Must Put Demand-side Efficiency, Flexibility First

Policy Forum Launches 'Demand Is New Supply' as Industry, Policy Imperatives

By K Kaufmann

WASHINGTON — Gene Rodrigues, who heads the U.S. Department of Energy's Office of Electricity, managed to deliver a thundering, seven-minute keynote at the Alliance to Save Energy's Policy Forum on May 8 without so much as one de-rigueur mention of the Inflation Reduction Act, Infrastructure Investment and Jobs Act, or President Joe Biden's economic agenda.

Rather, he came to the forum to deliver a ringing endorsement of ASE's new campaign to convince the energy industry, state regulators and Capitol Hill lawmakers that "demand is the new supply."

In the past, the energy industry "looked at everything from one end of the microscope," said Rodrigues, who spent a large chunk of his 23 years at Southern California Edison working on demand-side initiatives. "If you need more reliability, if something goes down and you just need more power, if you need to ensure that everyone has access to the benefits of energy, then you … just build more. We need more, bigger plants. We need more transmission corridors. We need, we need, we need. That is the most inefficient way to think about solving the problem."

Creating a net-zero economy — with electrified buildings, transportation and industry — will mean major increases in energy demand, so using a full array of demand management strategies and technologies will be not only critical, but "obvious," he said. "It is a basic concept of efficiency, of ensuring that the steps we take are economic, impactful and they reach every single American no matter where he or she resides … It is an expression of common sense."

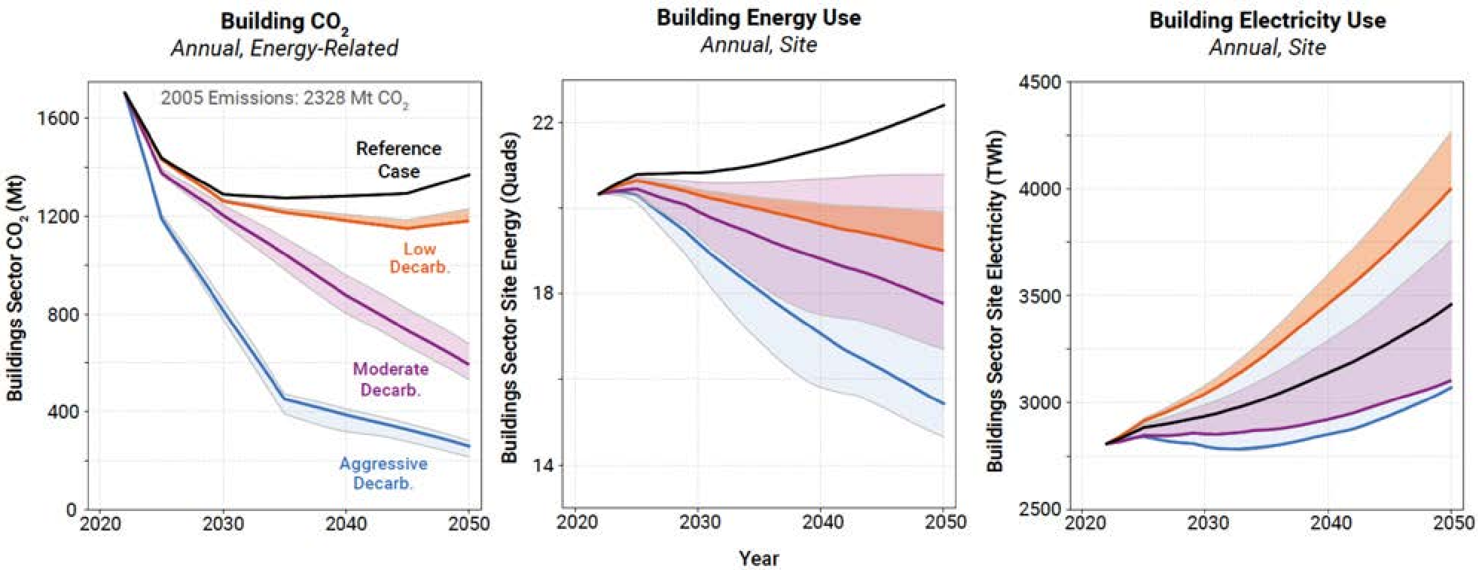
ASE CEO Paula Glover similarly framed the combination of aggressive efficiency and demand management as "the backbone of any energy transition that we aspire to have that is going to be equitable, reliable, resilient and affordable."

Demand is the new supply means "transforming energy demand into … dynamic, responsive supply. [It] is necessary and has to start now," Glover said in her opening remarks at the forum. "This approach is crucial for stabilizing our grids and distributing energy more equitably across communities."

Conference panels and speakers presented different approaches to growing demand management as supply, from the consumer and regulatory paradigm shifts needed to scale virtual power plants to new research from Lawrence Berkeley National Laboratory (LBNL) showing the impact of efficiency on regional load curves.

Gene Rodrigues, DOE assistant secretary for the Office of Electricity, delivered a rousing keynote at the ASE Policy Forum May 8. | *© RTO Insider LLC*

Electrification without aggressive efficiency could result in summer peak demand not only increasing, but shifting to later in the evening, said Andrew Satchwell, deputy leader in LBNL's Energy Markets and Policy Department. Produced in partnership with The Brattle Group, the study also found roughly half the regions studied could see a shift from summer to winter peaking due to the inefficiency of "a lot of electric resistance building heating," Satchwell said.



The LBNL-Brattle study found that by combining electrification with aggressive efficiency, the U.S. could reduce CO2 emissions from the building sector 91% below 2005 levels by 2050. | *Lawrence Berkeley National Laboratory*

FERC/Federal News

But the study also showed that a combination of aggressive demand- and supply-side measures could slash greenhouse gas emissions in the building sector to 91% below 2005 levels by 2050 without any major increase in building electricity use. Further, leveraging building efficiency and flexibility could provide $100 billion in power system savings per year by 2050, which could offset more than a third of the costs of grid decarbonization.

"We see a strong potential for energy efficiency to reduce emissions in the near term, while the grid is still decarbonizing, that then enables later reductions from … electrification under a harmonized grid," said Aven Satre Meloy, a computational research scientist and engineer at the Berkeley Lab.

Calling the study a "clear-eyed view of the economic case" for demand-side measures, Rodrigues ended his keynote with a call for industry stakeholders to "work on both ends of the scale to balance the grid. Demand is the new supply does not push anything off the table," he said. "For those who believe in all-of-the-above, it's just a way to work smart; work smarter, not harder."

Start Right Now

While utility executives frequently say that the least expensive kilowatt-hour is the one you don't use, demand-side initiatives in general have not had a strong profile in the energy transition.

In its *2023 Utility Scorecard*, the American Council for an Energy Efficient Economy found that the nation's 53 largest utilities had decreased their spending on efficiency by 4.9% in the five years since ACEEE's last utility rankings. That cut in spending resulted in a 5.4% decrease in energy savings and a 19% drop in peak demand reductions. On average, the ranked utilities spent 2.2% of their revenue on energy efficiency.

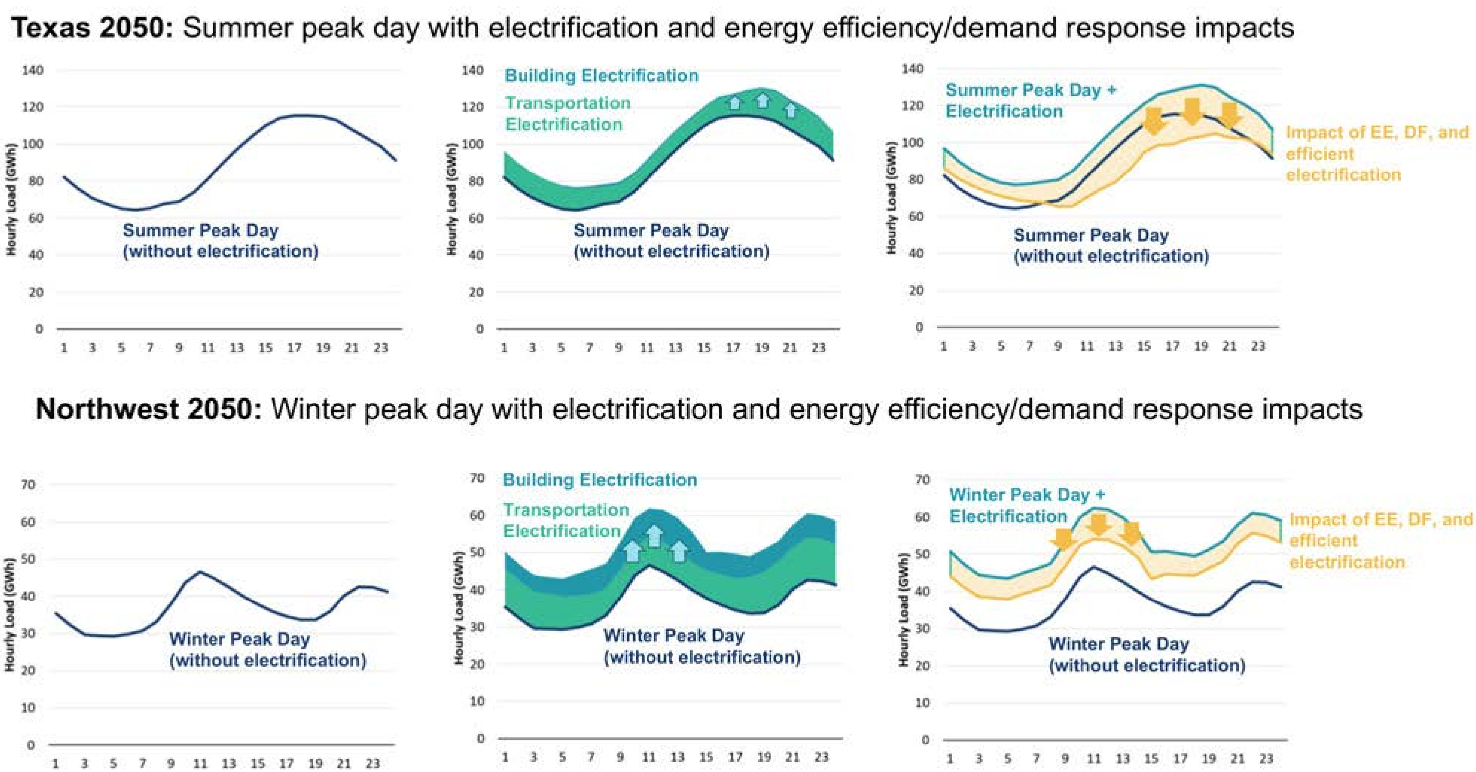
According to a *January 2024 tally* from the International Code Council, 13 states have adopted the latest, 2021 International Energy Conservation Code for residential buildings, while only 11 have adopted IECC 2021 for commercial buildings. Two more, Maine and Massachusetts, have adopted the 2021 updates as "stretch" codes.

IECC codes are updated every three years. Six states are still using the 2009 code.

The LBNL-Brattle study finds that an aggressive approach to efficiency and demand flexibility will be vital for the U.S. to have any chance of hitting Biden's goal of cutting economywide GHG emissions to net zero by 2050 without major increases in demand and grid impacts.

The scale of such efforts could be daunting. The building sector accounts for 35% of U.S. carbon dioxide emissions and 74% of electricity sales, according to LBNL. The study looks at a range of scenarios tracking the impacts of cutting both emissions and electricity consumption through various combinations of electrification and low, moderate and aggressive energy efficiency and demand management.

LBNL's most aggressive scenario would require 98 million to 141 million fossil fuel or electric-resistance water heaters to be replaced with heat pump water heaters by 2050, as well as high-efficiency retrofits for building envelopes on 109 million existing homes and up to 43 billion square feet of commercial space. Advanced HVAC controls would also be needed for more than 75% of homes and 50% of commercial buildings.



Efficiency and flexibility mitigate electrification load increases in both summer- and winter-peaking systems. | *Lawrence Berkeley National Laboratory*

And, Satre Meloy said, "It needs to start happening right now in order to achieve that very dramatic or very favorable building-centric future in 2050."

Electrification with no or low efficiency would cut CO2 emissions but almost certainly would result in increased electricity demand, the study finds. The impacts of moderate and aggressive efficiency are more variable; emissions would go down, but electricity use could rise or fall, depending on a range of factors.

One example, the study's aggressive efficiency scenario factors in "breakthrough" technologies — such as super-efficient building envelopes and energy management systems — currently in the research and development phase but expected to reach commercial scale and price points by 2030 or 2035.

Increasingly rigorous building efficiency codes and standards will also be needed, Satre Meloy said. "Failing to do these things is substantially reducing the total avoided emissions" by 40% to 58%, he said.

The impacts on the grid also could be substantial, with "inefficient electrification" leading to increased peak and shifting demand patterns, Satchwell said. In Texas for example, the study found that efficient electrification could drive the state's summer peak down below a business-as-usual level. For a winter-peaking system in the Northwest, efficiency could cut in half any increase due to electrification.

Shifting the Paradigm

So, what it will take to get building efficiency and demand flexibility technologies — like virtual power plants — to commercial scale and well-integrated into distribution systems? The discussion during a panel on scaling VPPs centered more on paradigm and regulatory shifts than the technologies themselves.

For Jessica Granderson, director of LBNL's Building Technology and Urban Systems Division, buildings are an "underexploited resource" and the "central hub in the transfer of clean electrons in our energy transition to and from that clean grid."

"Our buildings have built-in storage already, right in the mass of the building, in the fabric of infrastructure, in the chilled and hot water that we're using to serve those loads," Gunderson said. "We have the technologies, the communications and the standards now [that] we didn't previously have to access that built-in storage and exercise it dynamically."

Mary Sprayregen, global head of regulatory affairs and global market development at Opower, sees a major misalignment between projections of growing residential energy efficiency and demand management and the current reality that about 8% of households are enrolled in utility demand-response programs.

"And that number has not changed over the last several years despite all the attention we are drawing to it," Sprayregen said. "How do we engage these untapped resources in everyday houses in a way that everybody can participate, but … that is not necessarily controllable, and it's not necessarily device-based, but it's behavior-based?"

Opower designs and runs such programs for utilities.

Marisa Uchin, chief strategy and growth officer at Franklin Energy, called for a reimagining of the power system "because we have distributed resources on the supply side hidden on the demand side. We have the opportunity to create the VPPs or to create sources of power that are … on a different size and scale" and can be "distributed any place where potentially demand and supply chains are complex."

But technology changes at the residential level are generally driven by comfort, upfront cost and a crisis — the breakdown of a major appliance — Sprayregen said.

Granderson agreed but called for "changing that paradigm to something that is like where our decisions are system-optimal, and I think, we have to be really cognizant and intentional that that is the change we're looking to drive. … So, we're going to think about the ways we combine those solutions to reach everyone in different markets and contexts."

Another major hurdle for Sprayregen is designing appropriate incentives for utilities to accelerate deployment of efficiency and demand flexibility. Regulatory decision-making is rooted in an inherent conflict between "capital expenditures versus operational expenditures," she said. "So, how do we get past that?"

Sprayregen, Granderson and Uchin all agreed that artificial intelligence will be the next critical tool for optimizing the system impacts of energy efficiency and demand management.

"When it comes to policymakers, specifically utility regulators, there has got to be a pathway where software solutions are on par with capital expenditures," Sprayregen said. "We've got to level that playing field." ■

CAISO/West News

Seams Concerns Won't Drive Day-ahead Market Decision, BPA Says

'Manageable' Issue Shouldn't Mean 'Categorical Rejection' of Markets+, Agency Contends

By Robert Mullin

The Bonneville Power Administration's choice of a day-ahead market will not be driven by concerns about the impact of the seams that would divide the two markets proposed for the West, an agency official made clear May 8.

"Bonneville is very aware that having two markets in the same or neighboring footprints presents seams that need to be managed. We are taking that into account," Russ Mantifel, BPA director of market initiatives, said during a virtual workshop with stakeholders. "But we think seams are manageable and that the existence of seams does not mean a categorical rejection of us joining Markets+."

The workshop was the agency's sixth such meeting on day-ahead markets and the first since agency staff issued its April 4 recommendation that BPA choose SPP's Markets+ over CAISO's Extended Day-Ahead Market (EDAM). (See *BPA Staff Recommends Markets+ over EDAM*.)

BPA's position on seams puts it squarely at odds with EDAM's most ardent supporters, who contend that a West divided into two markets would hamper the region's ability to fully tap the "diversity benefit" of its energy resources and varying load patterns. For those stakeholders, a single Western market with no boundaries represents the key reason for advancing toward a more organized electricity market.

Included in that camp are the industry stakeholders and state energy officials backing the West-Wide Governance Pathways Initiative, an effort to create the governance framework for an independent market that expressly includes the state-run CAISO and builds on the ISO's market platform.

"The seams issue is kind of a core question here," Fred Heutte, a senior policy analyst at the Northwest Energy Coalition (NWEC), said during the workshop. NWEC has been a long-time advocate for a single Western market.

Heutte asked for BPA's views on a February study by the Western Power Trading Forum (WPTF) and Portland, Ore.-based Public Generating Pool, which found that a seam between EDAM and Markets+ likely would create challenges beyond those seen at the boundaries of the full RTOs in the Eastern U.S., given that each market still would contain operating seams within them. (See *Western Market Seams Issues to Differ from East, Study Finds*.)

BPA transmission line | © *RTO Insider LLC*

Heutte linked his question to a comment in the BPA staff recommendation in favor of Markets+ that referred to the "complexities" of BPA needing to accommodate transmission customers (including Northwest investor-owned utilities) and "preference" customers who are not participating in Markets+ — or, possibly, either market.

"This is a really unique situation," Heutte said.

"I would say for Bonneville, it's not that unique," Mantifel responded, noting that BPA for eight years served customers participating in CAISO's Western Energy Imbalance Market (WEIM) before joining that market in 2022.

"Just to be clear about this, I believe Bonneville has lived and resolved these seams more than any other entity in the West," Mantifel said. "We have managed flows on our system for a market that we are not participating in, that we don't control the redispatch of outside of the coordinated transmission agreements."

"The seams are important. We hear the comments about seams. But Bonneville does feel that there's a way to make this work. We would encourage, we would invite FERC, for example, to get involved and encourage the market operators to work together," he said.

'Profound Difference'

Heutte said there is a "profound difference" between how the real-time — and voluntary — WEIM functions and how transmission must be handled in a day-ahead market, which would require prior commitment of both resources and transmission.

Heutte encouraged workshop participants to read the SPP-MISO *joint operating agreement* to get a sense of the complexity of transacting across market seams, calling the document a "sobering read." Given its role as the major transmission provider in the Northwest, BPA's positions would be even more complicated if it joins Markets+ while many of its neighbors join EDAM, he said, because both markets effectively would be running on top of its balancing authority area.

CAISO/West News

"With all the complexities ... [involved] with all the different potential positions of preference customers and transmission customers of Bonneville, this is a very, very complex thing to grapple with. I think it's really important to understand this is not the same as just merely an extension of EIM," Heutte said.

Mantifel said BPA understands that complexity "as well or better than anybody." The agency has already put a lot of thinking into the issue as an open access transmission provider, he said.

"We understand the differences, and we do think that there are very feasible methods of reconciling all these things and operating," he said. "We have done this, we think we can continue to do it, we think we can build on what we've done before and make it work."

'Multilateral' Issue

Lea Fisher, representing the Western Public Agencies Group (WPAG), asked if BPA will address the implication of seams in the business case accompanying its final decision of day-ahead market, "beyond the discussion you've included in the staff leaning where you outlined kind of the need to work through seams and some of the history and successfully doing that."

Mantifel said the Western Markets Exploratory Group (WMEG) studies prepared for BPA by Environmental+Energy Economics (E3) offer a picture of the economic benefits the agency would realize under multiple market footprints. (See *Study Shows Uneven Benefits for Calif., Rest of West in Single Market*.) E3 will provide "additional sensitivities" related to studies based on varying assumptions about transmission rates and "general market friction" at the seams, he said.

In terms of the "operational nature" of the seams, Mantifel said BPA is "eager" to have discussions with others in the region on the subject but hasn't "been able to find partners" for such talks.

"But we will use the best information available, including our own experience, in terms of operationally what we think scenes would look like. That being said, seams are definitively multilateral. Bonneville can't, on its own, make all the decisions or resolve all seams," he said.

Asked what steps BPA has taken to find willing partners for the seams discussion and whether it has reached out to CAISO, the agency told *RTO Insider* in an email: "The West appears to be on ... track for two day-ahead markets to operate concurrently. BPA is just saying the time to consider seams issues in that environment is now. BPA stands ready to work with entities in the regions to dig into the issue."

The need to address seams was a topic of discussion at an April 30 meeting of the Markets+ Participants Executive Committee (MPEC). (See *SPP's Stakeholder Process Attracts Markets+ Participants*.)

"It's not a secret to anyone that the biggest scenario around objection to Markets+ is the seam," said MPEC Chair Laura Trolese, with The Energy Authority. She said it would "behoove" the committee to start working on ways to reduce "transactional friction" as soon as possible rather than waiting until the end of the year.

Speaking at that meeting, Carrie Simpson, SPP's director of seams and Western services, said RTO staff has heard "loud and clear that we want to figure this out."

"I think there's still just confusion on how it works if we do nothing, and so I think starting there can help people identify what friction exists and what friction does not exist," Simpson said. "It's a very important issue to address, and so I think we let that [stakeholder] process play out."

But some stakeholders think that discussion would be premature before entities in the West decide which day-ahead market to choose.

"We can't really tackle this until we know where the boundary is," WPTF Executive Director Scott Miller said last month at the spring joint meeting of the Committee for Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB). "And so, when we get to that point, I think sometime this year, then we can engage meaningfully in what we can do to manage the seams that are unique to the day-ahead market." (See *Western Officials Get Rundown on 'Irritating, Inefficient' Market Seams*.)

During the BPA workshop, Oregon state Rep. Mike Gamba asked what the advantage to the Northwest would be "in BPA being in a different market that outweighs the obvious difficulties resulting in creating an unnecessary seam."

Mantifel said that notion assumes the two markets are equal.

"I would say that what we're trying to articulate is that Markets+ is a superior option for us, and I think what we're trying to move away from is the notion that these things are equal and that the only difference is one creates seams and another does not create seams," he said. ■

Calif. Grid Equipped for Summer, CAISO Says

4.5 GW Added to System Since September

By Elaine Goodman

CAISO officials are optimistic about the grid's performance this summer, as the system has added 4.5 GW of nameplate capacity since September, with an additional 4.5 GW on the way.

The figures are in CAISO's 2024 Summer Loads and Resources Assessment released May 9.

The *summer assessment* found that resources expected by this summer will suffice to meet forecast demand plus an 18.5% reserve margin for June through September.

In September, when California often faces its highest demand for electricity, CAISO's assessment showed at least 3,438 MW of capacity above the forecasted demand plus reserve margin during the 6-10 p.m. peak net load hours.

"Our findings provide a solid factual basis for going into the summer with optimism for maintaining reliability as the weather — and demand for electricity — begin to heat up between now and September and into October," Aditya Jayam Prabhakar, CAISO director of resource assessment and planning, said in a *blog post*.

In addition to the resource growth, the summer 2024 demand forecast has softened, CAISO said. Hydropower conditions are expected to be "average to slightly above average" after a winter that left the state's snowpack at 109% of the historical average.

Those factors combined will more than offset generation retirements and the transition of gas-fired generation into the state's strategic reserves, CAISO said.

However, the summer assessment notes it doesn't take into account "extreme events" such as wildfires or regional heat waves "that continue to pose a risk for emergency conditions to the CAISO grid."

Two-pronged Analysis

For its analysis, CAISO used a probabilistic assessment of resources based on the California Public Utilities Commission's February 2024 preferred system plan along with a multihour stack analysis looking at energy sufficiency on peak days during each summer month.

CAISO projected that summer peak load will be highest in July, at 46,244 MW, followed by 45,972 MW in September and 45,059 MW in August.

CAISO's all-time high peak load was 52,061 MW on Sept. 6, 2022, at 4:58 p.m., amid an extended heat wave, the ISO *reported*. Rolling blackouts were narrowly averted when the Governor's Office of Emergency Services sent out text messages urging consumers to conserve electricity. (See *CAISO Reports on Summer Heat Wave Performance*.)

Last summer, CAISO issued level 1 energy emergency alerts on three days in July, which were attributed to high levels of exports to the Southwest. (See *CAISO DMM: High Exports to Southwest Led to July EEAs*.)

Weather forecasts show that above-normal temperatures are probable across the West this summer, especially in the desert Southwest in August and September. Above-normal temperatures are less likely in coastal areas.

CAISO has access to emergency resources, the summer assessment noted.

Under the Electricity Supply Strategic Reliability Reserve Program (ESSRRP), the lifetimes of three gas-fired generating stations — Alamitos, Huntington Beach and Ormond Beach — were extended to support the grid during extreme events. Their combined capacity is about 2,859 MW.

Additional resources include the Demand Side Grid Support (DSGS) program, which the California Energy Commission launched in August 2022, and the Distributed Electricity Backup Assets (DEBA) program.

Resource Growth

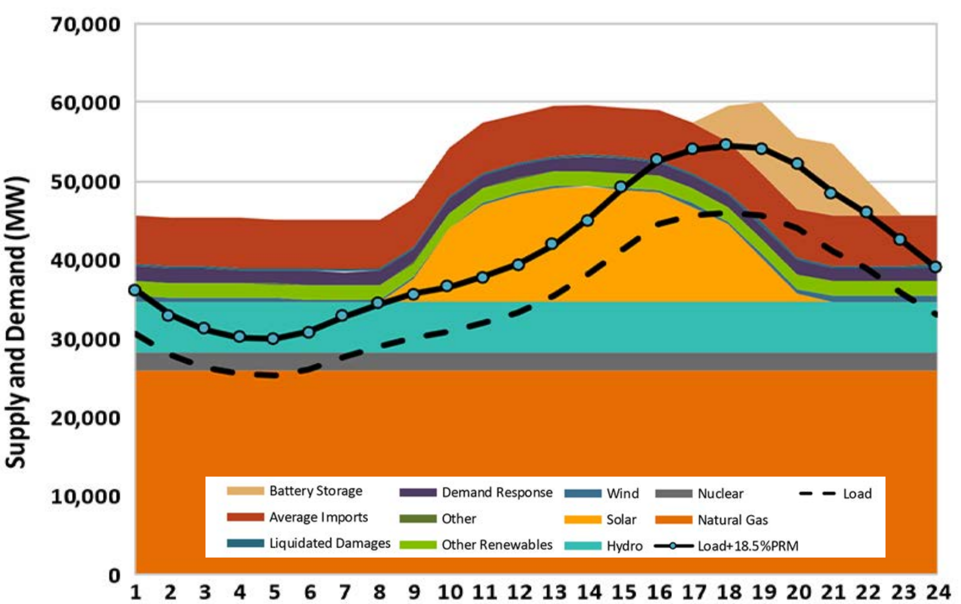
From September through December, CAISO's capacity grew by 3,576 MW, including 1,842 MW of solar and 1,321 MW of battery storage.

An additional 926 MW of capacity was added in the first three months of 2024. And from April through June, an additional 4,569 MW of capacity is expected, with 818 MW of solar and 3,199 MW of battery storage.

Gov. Gavin Newsom (D) noted battery storage's growing role in California in a release April 25. California reached 10,379 MW of battery storage in April, up from 770 MW in 2019, Newsom's office said.

Also during April, battery storage discharge exceeded 6,000 MW for the first time, and batteries were the largest source of grid power supply at one point during the day.

"Our energy storage revolution is here, and it couldn't come at a more pivotal moment as we move from a grid powered by dirty fossil fuels to one powered by clean energy," Newsom said in a statement. ■



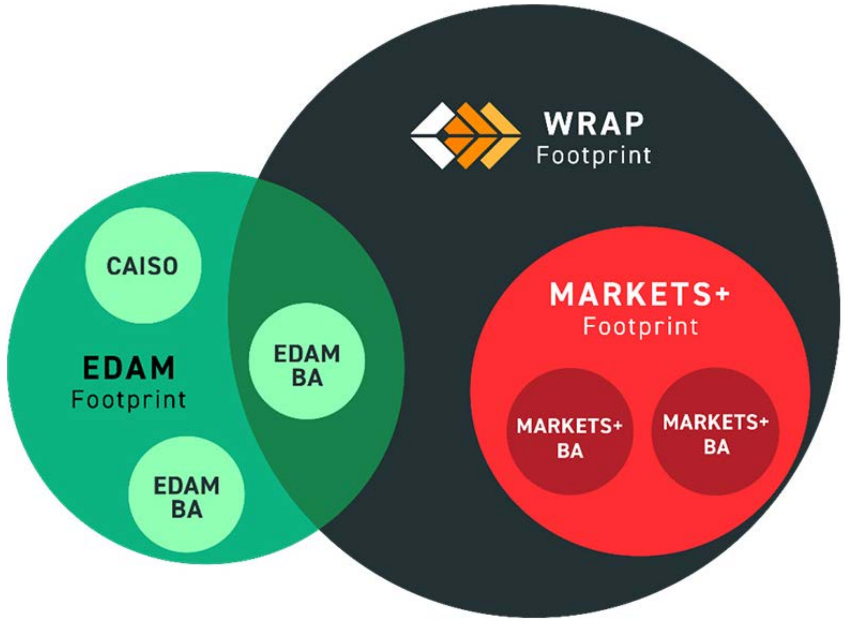
A CAISO analysis finds that expected resources are sufficient to meet forecasted demand plus an 18.5% reserve margin for all summer months in 2024. | *CAISO*

CAISO/West News

WRAP 'Binding' Phase Delay Finds Stakeholder Support

'Getting It Right' is Most Important, Participants Say

By Ayla Burnett



Potential Western Resource Adequacy Program participants are asking to delay the program's 'binding' phase by one year due to capacity concerns. | *Western Powerpool*

Members of key Western Resource Adequacy Program (WRAP) stakeholder groups have expressed support for a recent move by participants to delay the program's "binding" penalty phase by one year, to summer 2027.

Those stakeholders shared their views during a May 8 meeting of the WRAP's Program Review Committee (PRC), a sector representative group "charged with receiving, considering and proposing design changes" to the RA program operated by the Western Power Pool (WPP).

They were reacting to an April 22 letter by the WRAP's Resource Adequacy Participants Committee (RAPC) seeking the delay and outlining a number of concerns in meeting RA obligations in summer 2026, including supply chain delays, rapid regional peak load growth and extreme weather events that could affect participants' ability to procure enough capacity to meet resource adequacy requirements. (See *WRAP Participants Seek 1-Year Delay to 'Binding' Operations*.)

Members of WPP's voluntary program face a May 31 deadline to commit to binding operations by summer 2026, which would subject participants to penalties for capacity deficiencies.

PRC member Ray Johnson, deputy general manager with Tacoma Power, reiterated the concerns set out in the letter.

"The intent is to close the gap on some capacity deficits, but supply chains are causing delay," Johnson said. "It's very difficult in this current environment to procure or build all the capacity that's required in the time frame that we're currently operating under. And so, the modifications will enable a little bit more of a ramp into the program and then enable the program to be fully binding, I think, in early 2029."

Asked to clarify Johnson's 2029 reference, Tacoma Power told *RTO Insider* in an email that Johnson was referring to the first year beyond the program's phase-in transition period set out in the WRAP tariff, which ends in 2028.

"They are still working toward a critical mass of participants electing binding operations for summer 2027, which falls in the existing transition period window," a utility spokesperson said.

Rebecca Sexton, director of reliability programs at WPP, said the one-year delay is "not technically a loss."

"This current undertaking here to select summer 2027 is well within the current tariff, so we don't really see it as a delay," Sexton said. "It does mean kind of a paradigm shift of what we think about binding. I think the terms that are being preliminarily discussed for the transition would hopefully encourage folks, even if they can't meet the expectations of the WRAP program, to still be a binding participant."

Non-utility Perspectives

Non-utility stakeholders agreed that they don't want the program to enter the 'binding' phase until it includes a critical number of participants.

"I fully appreciate that this program is going to be more successful if we get this critical mass and everybody is in it together, and to incent that, I see why we proposed kind of ramping in," said Ben Fitch-Fleischmann, director of markets and transmission at Interwest Energy Alliance.

Sommer Moser, an attorney representing Alliance of Western Energy Consumers (AWEC), shared a similar view but said it did not reflect a formal position from AWEC.

"Taking the time to get things right to make sure that we are eliminating inefficiencies and being thoughtful about implementation tends to lead to a program that is more cost effective and [has] greater benefits for participation," Moser said. "I was a little concerned at the delay but ultimately think that getting it right is most important." ■

West news from our other channels

Environmental Groups Urge CEC to Fund EV Truck Chargers

NetZero Insider

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

ERCOT News

3 GW of Storage Help ERCOT Through Scarcity

By Tom Kleckner

Energy storage resources bailed out the ERCOT grid May 8, providing a record amount of energy to help the Texas grid operator through the first tight conditions of the maintenance season.

Discharging batteries provided 3,195 MW at 8:05 p.m. CT, according to *Grid Status*, meeting 5% of demand for the first time and smashing the previous record by more than 1 GW.

"The future is here!" former FERC Chair Pat Wood, now Hunt Energy Network's CEO, *said* on social media.

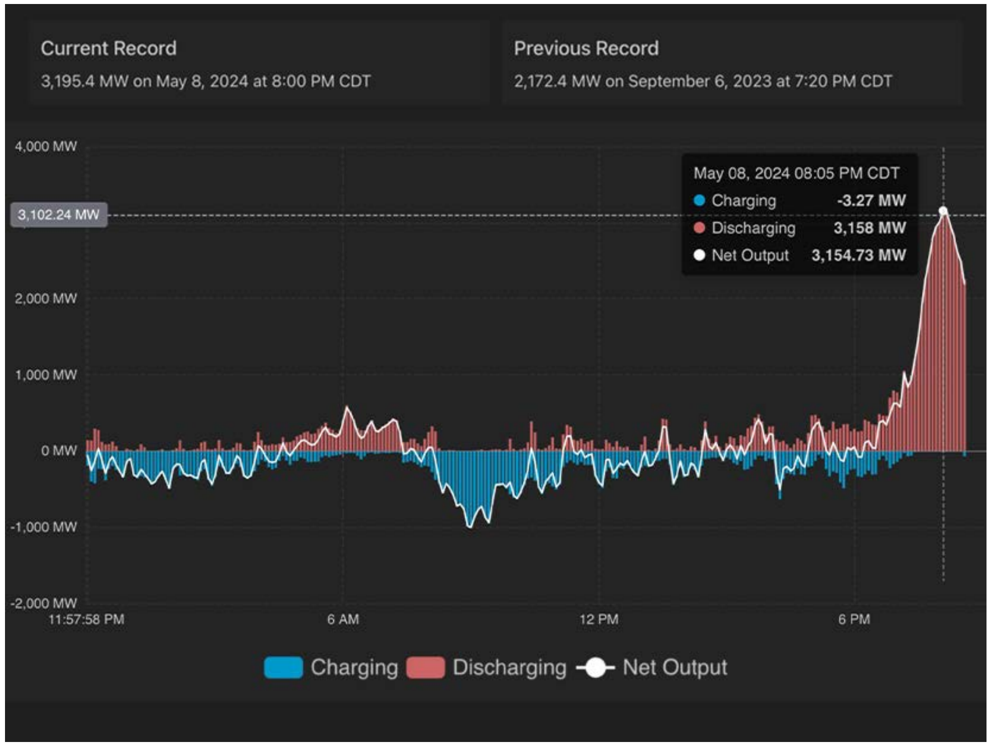
The old mark came Sept. 6 when ESRs provided 2,172 MW of energy after a voltage drop forced ERCOT into emergency operations for the first time since Winter Storm Uri. (See *ERCOT Voltage Drop Leads to EEA Level 2*.)

ERCOT began the year with 3.3 GW of storage capacity. That is expected to double by the end of the year, but an additional 145 GW of storage capacity is in the interconnection queue.

The ISO had issued a *weather watch* for the day because of "unseasonably" high temperatures, high levels of expected maintenance outages and the potential for lower reserves. Weather watches are not calls for conservation, ERCOT says.

The heat index at DFW Airport reached 103 degrees Fahrenheit.

The grid operator's *May resource adequacy forecast*, distributed in March, assumed 14.7 GW of thermal assets would be offline during the month. Instead, 24.7 GW of the resources were offline May 8, according to the ERCOT dashboard. The same forecast also predicted 2 GW of energy storage availability.



Energy storage resources exceeded 3,000 MW for the first time May 8. | *Grid Status*

Peak load averaged 68.9 GW during the hour ending at 5 p.m. ERCOT's record is 85.5 GW, set last August.

Prices neared their $5,000 cap during the interval ending at 8:15 p.m.

ERCOT on May 3 issued a *request for proposal* for 500 MW of demand response, primarily in the San Antonio area. The grid operator has established a generic transmission constraint south of the city to address power flow limitations over transmission lines.

The RFP was issued May 8. ■

ISO-NE News

ISO-NE Predicts 10% Increase in Peak Demand by 2033

By Jon Lamson

ISO-NE is predicting that New England's peak load will increase by about 10%, and electricity consumption by 17%, by 2033, according to its 2024 Capacity, Energy, Loads and Transmission (CELT) *report*, released May 1.

The increasing peak load forecast is driven by increasing transportation and building electrification, ISO-NE said. The estimate is a slight decrease from the peak load projections in the 2023 CELT report. (See *ISO-NE Decreases Its 10-year Peak Load Forecast*.)

While the New England grid is currently a summer-peaking system, ISO-NE projects the winter peak to grow significantly faster, with a projected increase of about 33% over the next decade.

In 2033, ISO-NE expects the region's summer peak to reach 27,052 MW and the winter peak to reach 26,768 MW. The RTO expects that winter peaks will surpass summer peaks in the mid-2030s because of heating electrification.

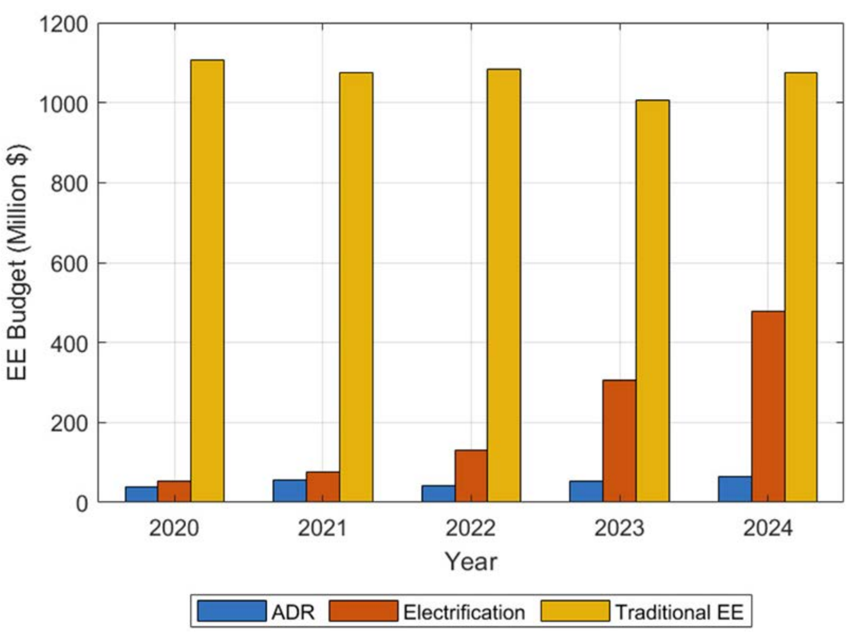
The New England power system reached its peak load in 2023 on Sept. 7, topping out at just over 24,000 MW.

Energy use in New England has declined since the early 2000s, largely because of energy efficiency programs and behind-the-meter solar. However, ISO-NE projects the amount of energy efficiency participating in its capacity market to decline in the coming years as states shift their focus toward building electrification and heating retrofits.

Historical and forecast net energy use in New England | *ISO-NE*

In a recent *presentation*, ISO-NE noted that state energy efficiency budgets "have remained consistent, while production costs have increased." In contrast, states have dramatically increased funding for electrification programs over the past four years and have slightly increased funding for active demand response.

ISO-NE projects that energy efficiency resources that expire and exit the market will outpace energy efficiency resource additions by 2029.



New England states' energy efficiency budget allocations | *ISO-NE*

"Since [Forward Capacity Auction] 14, the amount of expiring EE measures has been surpassing the pace of new EE cost-of-service agreements entering the market," ISO-NE spokesperson Mary Cate Colapietro noted.

2024 marks the fourth consecutive year in which the RTO's energy efficiency forecast has declined.

While ISO-NE had indicated that it expects BTM solar capacity to continue to grow at about 1,000 MW per year over the next decade, it projects that solar will only reduce the region's peak load by just over 200 MW by 2033. (See *NEPOOL Participants Committee Briefs: May 3, 2024*.)

Colapietro noted that increasing amounts of BTM solar "will shift the timing of peaks to later in the day when the panels produce less power."

ISO-NE projects that BTM solar will reduce total energy demand by about 10,000 GWh in 2033 — down 6.6% compared to gross energy demand — compared to about a 4,000-GWh reduction in 2023.

The RTO has said it plans to re-evaluate its methodology for forecasting energy efficiency and demand-reduction efforts in light of the states' shift away from traditional energy efficiency measures.

"The current method of using projections of EE counterfactuals to develop an accurate net energy and demand forecast has proven challenging and may introduce more uncertainty to the forecast than forecasting net of EE load directly," ISO-NE noted. ■

ISO-NE News

ISO-NE: RCA Changes to Increase Capacity Market Revenues by 11%

By Jon Lamson

ISO-NE's proposed resource capacity accreditation (RCA) updates would result in an estimated 11% increase in capacity market revenues, the RTO told the NEPOOL Markets Committee on May 7.

Despite the overall increase, ISO-NE projects *revenues* to vary significantly based on resource class. The modeling showed that compensation for gas, dual fuel, energy efficiency, solar and imports would increase, while revenues for oil, energy storage, active demand response, wind and hybrid resources would decrease.

The RTO also estimated that the RCA updates would reduce the loss-of-load expectation by about 38%.

Initially introduced in 2021, the RCA project is intended to better align ISO-NE's capacity market with the reliability contributions that different resources provide to the grid. Accreditation values would be based on a given resource's expected output during the hours of greatest reliability risk.

The RTO emphasized that the revenue results are dependent on the modeling assumptions and are likely to change as the resource mix and seasonal risk profile shifts. The RTO's modeling indicates that near-term reliability risks are concentrated in the summer, and it projects that winter reliability risks will rise dramatically as heating electrification intensifies and winter peak loads will surpass summer peaks in the mid-2030s.

The seasonal risk balance likely significantly affects the revenues projected for gas-only resources. While one of the main drivers of the RCA project was to better account for gas constraints during winter months, ISO-NE projects that the changes will increase gas-only resources' revenues by 11% (coincidentally). This increase is attributed in part to the concentration of risks in the summer, when gas resources face minimal constraints, ISO-NE said. As winter reliability contributions become more important, gas constraints will have a greater impact on capacity accreditation, likely reducing revenues.

The design of the capacity auction could also significantly change before the RCA updates are implemented.

ISO-NE is proposing to shift its capacity auction from a forward annual design, with the auction for each yearlong capacity commitment period (CCP) held over three years in advance, to a prompt seasonal design, with auctions held much closer to the CCP, which would be broken up into seasonal segments.

If FERC accepts ISO-NE's proposal to delay Forward Capacity Auction 19 an additional two years, the RTO "will focus on evaluating scope and phasing of work for a combined accreditation design with a seasonal/prompt capacity market to implement for CCP 19 and would target discussing initial scope considerations with the MC in July," said the RTO's principal analyst, Dane Schiro.

Despite the uncertainties, the RTO's presentation provides the most detailed look to date at how the changes will ultimately impact resource compensation.

ISO-NE projects dual-fuel resources to have the largest increase in total revenue, about $78.3 million (19.8%), followed by a class of non-intermittent resources including coal, nuclear and wood-burning generators at $50.6 million (29.1%); gas-only resources at $38.7 million; energy efficiency at $36.5 million (38.3%); imports at $22.5 million (81.1%, the largest percentage increase); and non-intermittent hydro at $16.1 million (29.4%).

Meanwhile, ISO-NE estimated that energy storage (including both batteries and pumped hydro) would have the most significant decrease in revenue, about $58 million (36.7%), followed by oil-only resources at $12.8 million (11.9%), hybrid resources at $6 million (52.1%, the largest percentage decrease), active demand response at $5.8 million (23.2%) and wind at $4 million (8.7%).

Alex Chaplin of New Leaf Energy told *RTO Insider* the company is concerned that the projected revenues indicate the updated accreditation methodology may undervalue storage resources.

"Some New England states have energy storage goals and have implemented (or are working to implement) incentive programs for storage to help address the 'missing money' problem batteries face," Chaplin wrote in an email. "We fear that a significant reduction in capacity revenues will worsen the missing money problem and negatively impact storage deployments in the region."

Aleks Mitreski of Brookfield Renewable expressed perplexity about why storage resources experienced such a significant reduction in capacity revenues relative to fossil resources, adding that the differences may stem from how ISO-NE models the physical parameters of various resource classes.

"Pumped storage resources that operate every day receive a sizable capacity payment reduction of 36%, while oil units that run a few days of the year only get a 12% payment reduction," Mitreski told *RTO Insider*. ■

The Bucksport Power Station in Bucksport, Maine | *JERA*

ISO-NE News

How Sea Level Rise, Coastal Flooding Threaten Boston's Grid

Mass. Utilities Being Challenged to Prepare for Impacts of Climate Change

By Jon Lamson

For much of its early history, Boston was a city expanding into the sea.

A hilly peninsula prior to colonization, the city began the labor-intensive process of removing its hilltops to fill in the surrounding coves, marshes and mud flats at the end of the 18th century.

The summit of Beacon Hill, adjacent to the Massachusetts State House, was carted off in the early 1800s, while Mount Vernon and Pemberton Hill, which formed the peninsula's "Trimountain" landmark alongside Beacon Hill, fared even worse. In the words of Boston historian Walter Muir Whitehill, "the hills have all but disappeared."

Today, over half the city is built on a landfill foundation of former hilltops and assorted city waste. As a result, a major portion of Boston's streets, bars, apartments and power infrastructure are located just above the historical flood lines.

The outward expansion has enabled Boston to become the city it is today but has also made it especially vulnerable to the rising tides that threaten to force the city into retreat.

By 2100, the sea level around Boston is projected to rise by two to five feet, according to a 2022 *report* by the University of Massachusetts Boston.

The report projected precipitation intensity to increase by 20 to 30%, while sea level rise will likely push up *groundwater levels* and increase groundwater salinity along the coast. If emissions continue at current rates, 100-year flooding events could become annual occurrences by the end of the century.

"Risk-averse end users of these projections should consider the possibility of sea level outcomes above the likely range, especially under higher GHG emissions," the UMass report noted. "For long-term planning and long-lived coastal assets, we stress that sea level will continue rising beyond 2100 under all GHG emissions scenarios."

Rising Costs of Resiliency, Recovery

In Boston and throughout the broader region, climate-fueled extreme weather events are already stressing essential energy infrastructure.

"We see a lot of concern about the ability of the grid to withstand even current — not to mention future — storms, sea level rise and other climate impacts," said John Walkey, director of climate justice and waterfront initiatives at the environmental justice nonprofit GreenRoots.

As climate change accelerates, "all our past planning and forecasts go out the window," Walkey said.

Massachusetts' electric utilities have incurred major costs associated with storm recovery in recent years. Eversource, one of the state's two major electric distribution companies, is seeking to recover about *$339 million* in costs associated with three storms that occurred between 2021 and 2022, including $176 million from a single 2021 Nor'easter (D.P.U. 22-143).

Over the past decade, Eversource's contributions to its storm fund, which is intended to stabilize the impacts of storm costs on ratepayers, have increased from about *$5 million* to *$31 million* annually (D.P.U. 22-22).

In the fall of 2021, Eversource reported that its storm fund had a $122 million *deficit*, which the company attributed in part to increasingly

The Charles River in Boston | *The City of Boston / Sasaki*

ISO-NE News

frequent storms "due to weather patterns and meteorological characteristics associated with climate change."

In a recent interview, Massachusetts Department of Public Utilities Chair Jamie Van Nostrand emphasized that it is the utilities' responsibility to prepare their systems for increasing pressures from climate change.

With more frequent and severe extreme weather events and increasing property values, elevated storm costs are "not necessarily a matter of the utilities being imprudent," Van Nostrand told *RTO Insider*. "But we'll also be looking closely at, 'Could that have been avoided? Could you have designed your system in a way that would have been more resilient?'"

In 2022, Massachusetts passed a *bill* requiring the state's electric utilities to file electric-sector modernization plans (ESMPs) with the DPU every five years. The bill requires the utilities to detail how they plan to upgrade their systems to facilitate the clean energy transition and mitigate climate damage. (See *Mass. Utilities Submit Grid Modernization Drafts*.)

The utilities filed their final plans in January, which the DPU should rule on in late August, Van Nostrand said.

"Even without that specific statutory directive, I think that part of our job is to put the utilities on notice that we're watching, and we want you to take [climate resilience] into account," Van Nostrand said, adding that utilities will "run the risk of a prudence disallowance" if they incur costs that could have reasonably been avoided by proactive climate mitigation."

The utilities' ESMPs outline major investments to meet increasing peak loads and enable the transition to more distributed generation. Eversource *estimates* it will need to build 17 new substations and upgrade 26 substations by 2035.

"It's very timely that we're looking at the climate change resilience piece," Van Nostrand said, "because we're going to be installing a lot of substations, upgrading a lot of substations, and we want to make sure the utilities are mindful as they're making all these investments."

While storm costs are often driven by downed trees and branches, large flooding events can pose a significant threat to substations.

National Grid, Massachusetts' other major electric utility, noted in its *ESMP* filing that flooding in its Rhode Island service territory in 2010 forced the company to remove eight substations from service and caused "significant customer outages and loss of high-value substation equipment."

The company wrote that it used Federal Emergency Management Agency (FEMA) flood maps to analyze its substation fleet in the aftermath of the events to identify vulnerabilities.

"Flood mitigation efforts have been implemented at approximately 40 substation locations with approximately 20 additional projects planned," National Grid wrote.

Elli Ntakou, Eversource's manager of system reliability and resiliency planning, said the utility assesses risk based on FEMA flood data and sea level rise projections from the City of Boston and the National Oceanic and Atmospheric Administration.

"Especially for sea level rise, we want to be comprehensive," Ntakou said.

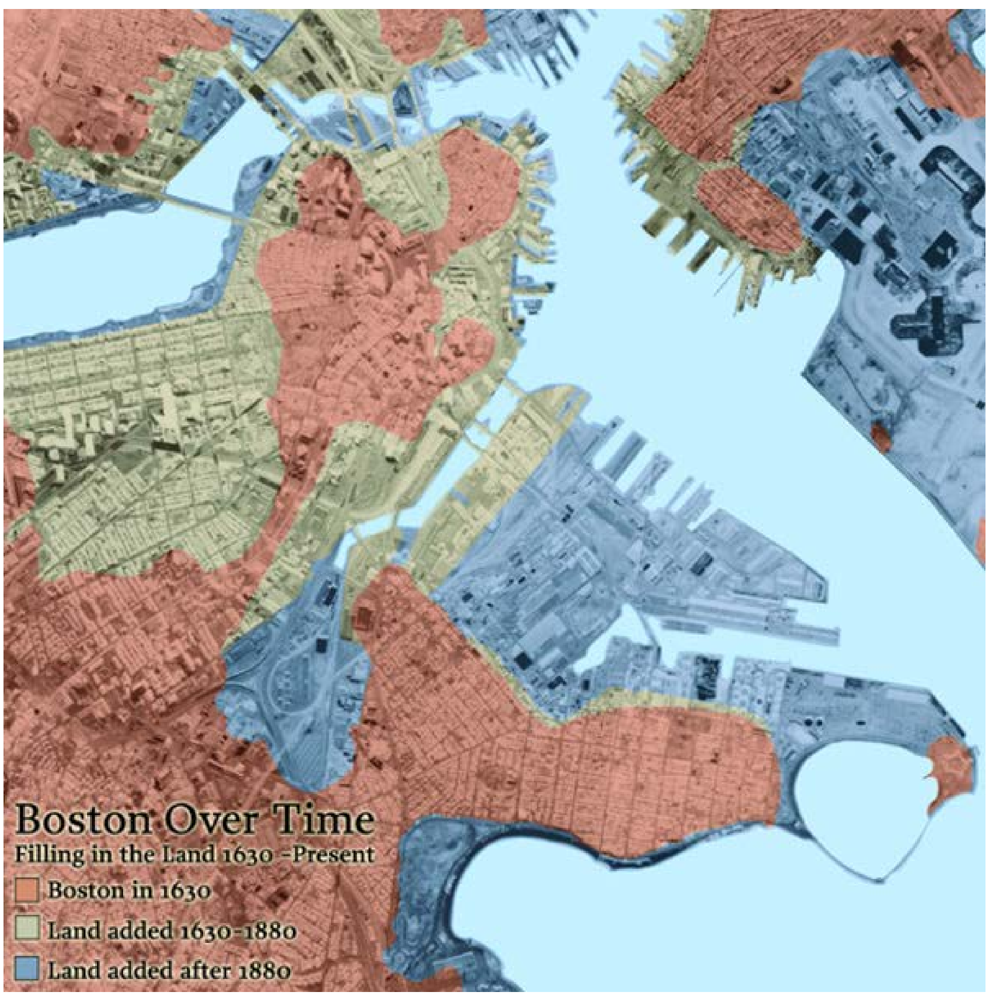
Elevation in East Boston

Sea level rise resiliency has been one point of contention in the lengthy fight over Eversource's proposed substation on the banks of Chelsea Creek in East Boston, which has led to demonstrations and *arrests* of protesters attempting to stop construction.

Environmental justice organizations and residents have argued that Eversource failed to conduct adequate community engagement on the project and have expressed concern that future climate-driven flooding could inundate the substation, endangering the surrounding neighborhood.

GreenRoots and the Conservation Law foundation have a pending legal challenge before the Massachusetts Supreme Judicial Court regarding the Energy Facilities Siting Board's (EFSB's) approval of the project (EFSB 14-04A).

"We don't feel as if they really prepared for the lifespan of this facility, [or] they prepared for the lifespan of a transformer," said Walkey of GreenRoots, adding that substations can last for over a century.



Boston topography 1630 to present | *The Boston Public Library*

ISO-NE News

Eversource considered sea level rise over a 40-year equipment lifespan and selected a design flood elevation — "the lowest elevation at which the Substation equipment should sit on the site" — of four feet above the 500-year flood line.

Eversource said the substation "was approved following a comprehensive, yearslong public review process" and that the company "comprehensively demonstrated that the project is designed to mitigate flood risks well beyond any flood study for the project."

The EFSB ruled that Eversource "appropriately addressed risks associated with sea level rise" and added that "building the substation at a higher elevation would likely add costs to project development and provide unclear benefits."

Future Uncertainty

One major challenge of planning for coastal flooding is the high level of uncertainty associated with projecting future emissions, as well as how largescale earth systems will react to different warming scenarios.

While Boston is likely to experience sea level rise of two to five feet, "that's really all we can say, because it depends on the emissions of greenhouse gases," said Paul Kirshen, professor of climate adaptation at UMass Boston and a lead author of the UMass climate impacts report.

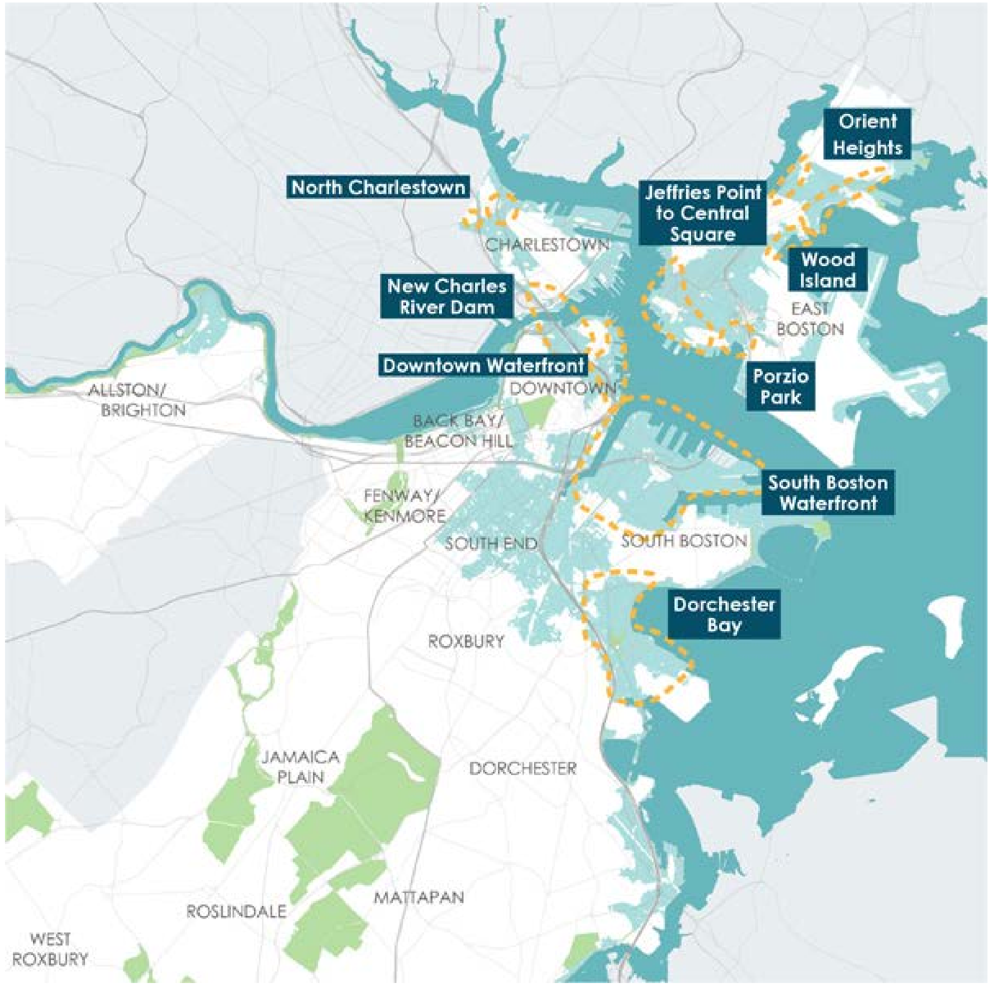
"If we can get to net zero by 2050, it could only be two feet. If we keep on the rate we're going, it could be five feet," Kirshen said.

He added there is an "outside chance" that sea level rise could reach up to 10 feet by the end of the decade, depending on the degree of melting on ice sheets in Greenland and Antarctica.

"It's a low probability," Kirshen said, "but that would obviously be a real game changer."

Climate change could also increase the potential for low-probability, high-consequence compound flooding events in which river flooding coincides with a storm surge, Kirshen said.

"We're at the confluence of three rivers — the Mystic, the Charles and the Neponset River — and there's always the possibility of those rivers being flooded from precipitation at the time that we get a major coastal storm," Kirshen said. "Not only would you get flooding from the ocean from the storm surge, but you'd also get the Charles River and the Mystic River overflowing their banks."



Projection of a hundred-year flood with three feet of sea level rise | *City of Boston*

To help account for the changing climate risk profiles, in recent years the DPU has mandated that newly sited projects reassess their climate vulnerability every five years and take any additional necessary mitigation measures.

"It just makes sense if you're installing energy infrastructure that's going to have a lifespan of 30, 40, 50 years," said DPU Chair Van Nostrand. "We're always getting more information, and if anything, I think the information we've gotten is a little bit scarier. … Sea level rise might be even worse than we were thinking."

Some environmental organizations and legislators are looking to require even more comprehensive climate resilience planning from the utilities. One *bill* reported favorably out of the legislature's Telecommunications, Utilities and Energy Committee would require the state's investor-owned utilities to submit a climate vulnerability assessment and adaptation plan every five years.

Johanna Epke, staff attorney at the Conservation Law Foundation, said current requirements have provided limited visibility into how the utilities are planning for climate impacts.

"They're not required to file any of their modeling or any of their assessments," Epke said. "We want that out in the public space, we want to be able to scrutinize that, and we want to have experts in the advocacy community comment on that."

Van Nostrand said he thinks the DPU already has the statutory authority to require climate vulnerability assessments as part of the ESMP process.

"As a result of the 2022 climate law, we will be making specific findings on climate vulnerability assessments when we issue the August order on this first round of ESMPs," Van Nostrand said. "Apart from that, we can also rely on our broad regulatory oversight powers to be able to say, 'We think that it's part of utility practice that you perform this kind of a study and manage your system in a way that manages risks.'" ■

MISO News

Canada Pension Board, Global Infrastructure Partners to Buy Allete

By Amanda Durish Cook

Canada's pension board and a private equity firm intend to buy Duluth, Minn.-based energy company Allete for $6.2 billion, which appears to make some Minnesota regulators apprehensive.

Allete announced May 6 that it entered into an agreement to be acquired by Canada Pension Plan Investment Board (CPP Investments) and Global Infrastructure Partners (GIP). The two would disperse $67/share to shareholders and assume Allete's debt.

Following the acquisition, Allete would become a private company, no longer traded on the New York Stock Exchange. The sale is scheduled to close next year and requires approvals from shareholders, Minnesota and Wisconsin regulators, FERC, the Federal Trade Commission, and possibly others.

In a press release, Allete CEO Bethany Owen said the transaction would grant Allete "access to the capital we need" to serve customers and hit clean energy targets as the fleet transitions.

"CPP Investments and GIP have a successful track record of long-term partnerships with infrastructure businesses, and they recognize the important role our Allete companies serve in our communities as well as our nation's energy future," Owen said. "Together, we will continue to invest in the clean energy transition and build on our 100-plus-year history of providing safe, reliable, affordable energy to our customers."


Allete CEO Bethany Owen | *Allete*

Allete's Minnesota Power, which serves about 150,000 residents and industrial customers across 15 municipalities, must reach Minnesota's 100% carbon-free electricity mandate by 2040.

Allete also boasts clean energy developer Allete Clean Energy and North Dakota-based wind operator Allete Renewable Resources in addition to BNI Energy in North Dakota; Superior Water, Light and Power in Superior, Wis.; and distributed solar energy developer New Energy Equity.

Owen framed the transition to private ownership as a positive development, allowing Allete to draw on its owners' financial resources instead of having to issue equity in the markets. She said, "strong partners will not only limit our exposure to volatile financial markets, it also will ensure Allete has access to the significant capital needed for our planned investments now and over the long term."

CPP Investment Board has about $591 billion Canadian dollars (about $432 billion USD) in assets; it oversees the retirement funds for approximately 21 million Canadians. GIP manages $112 billion with a focus on energy, transportation, digital infrastructure, and water and waste management. GIP is set to provide 60% of the equity to purchase Allete, with CPP Investments providing the remaining equity.


Minnesota Power's headquarters in Duluth, Minn. | *Allete*

Earlier this year, BlackRock announced it plans to acquire GIP for $3 billion of cash and approximately 12 million shares of BlackRock common stock. That negotiated deal hasn't been finalized and is awaiting FERC approval (EC24-58). BlackRock already owns 13.55% of Allete.

Minnesota regulators appeared apprehensive of Allete's reclassification as a private company owned by investment firms during a special planning meeting May 9 discussing the possible sale.

There, Owen emphasized the acquisition wouldn't mean a change in day-to-day operations or customer rates. In the press release, Allete said its headquarters, leadership, workforce, compensation and charitable contributions would remain undisturbed.

"Allete is a relatively small company doing big, important things," Owen told regulators, adding that becoming a privately held company will help it raise more than double its current, roughly $3.4 billion market value for new infrastructure projects.

Owen said Allete will file a petition for approval of the sale with the Minnesota PUC and the Public Service Commission of Wisconsin sometime in July.

GIP founding partner Jonathan Bram said he's certain regulators will thoroughly evaluate the acquisition's details.

"There haven't been a lot of acquisitions like this in front of the commission," Minnesota Public Utilities Commission Chair Katie Sieben said. She asked how the sale would affect Allete's transparency.

Minnesota Power Vice President of Regulatory and Legislative Affairs Jennifer Cady said even though Minnesota Power wouldn't have to make SEC filings going forward, transparency would continue through rate cases and FERC Form 1 filings, alongside other FERC filings. Cady also said the PUC could require more reporting as a condition of the sale.

Katherine Hinderlie, manager of the Residential Utilities Division at the Minnesota Office of the Attorney General, said the likely amount of protected data in the sale means there's a good chance it will become a contested proceeding.

MISO News

Commissioner Hwikwon Ham said he worried that investor firms could lobby to weaken Minnesota's "strong" regulatory model.

GIP representatives said they're happy with Minnesota's regulatory model and don't plan to influence changes.

Allete has said that Minnesota Power and Superior Water, Light and Power will continue as "independently operated, locally managed, regulated utilities."

Minnesota Power is partial owner in a proposal to build the gas-fired Nemadji Trail Energy Center in Wisconsin. Plans for the plant hit a snag in April when the city council of Superior, Wis., didn't allow necessary zoning changes for construction to begin. (See City Council Vote Stalls Planned Wisconsin Gas-fired Plant.)

After announcing its sale, Allete canceled its first-quarter earnings call, scheduled for May 9.

In the press release, GIP CEO Bayo Ogunlesi said it and CPP Investments "look forward to partnering to provide Allete with additional capital so they can continue to decarbonize their business to benefit the customers and communities they serve."

"Bringing together Allete, with its demonstrated commitment to clean energy, with GIP, one of the world's premier developers of renewable power, furthers our commitment to serve growing market needs for affordable, carbon-free and more secure sources of energy," Bayo said.

Concerns over the BlackRock Connection

The announcement doesn't sit well with a nonprofit consumer advocate. Public Citizen Energy Program Director Tyson Slocum said the pending sale of GIP to BlackRock means that BlackRock — "a totally different animal" — would be the one to acquire Allete.

Public Citizen said it plans to lodge a protest with FERC over BlackRock's takeover of GIP considering the Allete deal.

Allete would "lose significant transparency" under its new ownership, Slocum predicted, and could be "consumed into BlackRock's black box" if the world's largest asset manager successfully obtains GIP.

Slocum said he expects GIP and CPP Investments to agree to short-term commitments along the lines of reducing rates, shielding customers from transaction costs and possibly decarbonizing Allete's fleet faster. However, he said impacts in the long run are murkier and entirely up to the new owners.

"The long-term issue of the utility going private can't be undone. That's the big issue here," Slocum said in an interview with *RTO Insider*. "If BlackRock is ultimately the owner, they can do whatever they want with their asset. This is a really, really serious move by BlackRock. Whatever assurances the companies are giving, you're losing transparency at the holding company level."

Slocum said SEC filings are not on par with FERC Form 1 filings, with the former occurring at the holding company level while the latter are at the franchised utility level. Comparing detailed SEC disclosures to FERC and state filings is a "tired talking point that is factually inaccurate," he said.

Slocum said nothing is stopping the new ownership from creating numerous LLCs to obscure investment decisions. It could have state commissioners playing "whack-a-mole" trying to regulate financial activities, he said.

Slocum said he worried that investor firm ownership would trade the existing influence of everyday shareholders to the "wealthiest 1% of the planet." He noted only a handful of utilities with captive service areas are privately controlled, including Puget Sound Energy, El Paso Electric, Cleco and Duquesne Light Co.

Slocum recommended the Minnesota PUC require BlackRock representatives attend upcoming meetings.

"Missing at that conference today was BlackRock," he said of the PUC's special planning meeting. "It looks like state regulators haven't wrapped their heads around this. Whatever hearing Minnesota has next, they must have BlackRock there."

BlackRock thus far has styled itself to FERC as a passive minority holder of utilities, Slocum said, and ownership of GIP would change that. He said federal agencies might consider splitting BlackRock in two so it can maintain both passive and active ownership of utilities.

"I have no idea how you navigate that unless you force a divesture," Slocum said.

Slocum also said BlackRock should abstain from the shareholder vote for GIP and CPP Investments to acquire Allete. Although BlackRock currently owns shares, participating in the vote would constitute a "clear conflict of interest" given its expected purchase of GIP. ■

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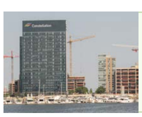

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MISO News

MISO, PJM Agree to Perform New Type of Joint Transmission Study

By Amanda Durish Cook

MISO and PJM announced they will embark on a new joint transmission study in the latter half of this year that concentrates on upping their interregional transfer capability.

The RTOs said they will be on the hunt for "opportunities for near-term transmission enhancements along the seam." The study would have MISO and PJM conducting joint transmission analysis and coordinated modeling.

The grid operators said increasing transfer capability between them could help overcome extreme weather and challenges posed by growing shares of intermittent resources in their fleets.

MISO and PJM said their announcement is driven by a chorus of calls for better interregional planning from the Organization of PJM States (OPSI), the Organization of MISO States (OMS) and the Midwestern Governors Association (MGA). OMS and OPSI sent a joint *letter* to the RTOs in February calling for more in-depth joint planning. Multiple environmental and consumer advocacy groups also penned their own joint letters asking MISO and PJM to undertake more comprehensive cross-border planning. (See *MISO, PJM Stakeholders Call for Interregional Transmission Overhaul*.)

MISO and PJM's announcement comes as FERC seems close to setting minimum levels of interregional transfer capacity and after the introduction of the BIG WIRES Act in Congress, which also calls for establishing minimum transfer requirements.

PJM Vice President of Planning Paul McGlynn said PJM looks forward to more planning coordination with MISO.

"Ensuring a reliable energy transition requires greater interdependence among regions and careful planning. Advancing this enhanced effort will benefit electricity consumers in each region," McGlynn said in a May 9 press release.

MISO Vice President of System Planning Aubrey Johnson said MISO and PJM have a long history of working together.

"[W]e understand the need to explore interregional planning, and with encouragement from OPSI, OMS and MGA, we will conduct a study that will address both near-term needs and create a model for future studies," he said.

The newest MISO-PJM study effort is considered separate from their usual interregional planning processes, which include coordinated system plans that can result in larger interregional market efficiency projects or the smaller, quicker targeted market efficiency project (TMEP) portfolios. It's not clear yet what projects will result, or if MISO and PJM will create a new class of interregional projects following the study.

"Similar to MISO and SPP's [Joint Targeted Interconnection Queue studies] as a new venture in interregional planning, this study between PJM and MISO is also a new venture to enhance interregional planning," MISO and PJM said in a statement to *RTO Insider*.

MISO and PJM said they believe the study "will provide a pathway to increase transfers between the two systems through near-term enhancements, working in collaboration with states and members."

Historically, the two approved one *interregional market efficiency project* in 2020 and have approved four sets of the *smaller* TMEPs aimed at relieving congestion since 2017. They haven't completed an interregional transmission planning study since 2022.

MISO and PJM's plans to coordinate their models for this study does not mean they will work from a joint model. The RTOs said their respective subject matter experts will work together "very closely" to line up assumptions to identify transfer needs and fixes that could expand flows between footprints. They said the new study could provide some "future opportunities" for seams modeling improvements. ■

| Northern Indiana Public Service Co.

MISO News

Ameren: MISO Missouri Capacity Shortfall Likely Inconsequential

Utility Shares Info on Capacity, Coal Plants, Transmission During Earnings Call

By Amanda Durish Cook

Ameren executives have reassured shareholders that Missouri's capacity shortfall beginning this summer is no cause for panic.

Speaking May 3 on a first-quarter earnings call, CFO Michael Moehn said he doesn't expect Missouri ratepayers to see "material" bill impacts from MISO's capacity auction. The utility also doesn't expect to encounter "any issues with providing reliable electric service throughout the year for our customers," he said.

MISO's recent capacity auction returned insufficient capacity for the upcoming fall and spring 2025 in Missouri's Zone 5, where capacity prices hit the $719.81/MW-day limit on par with building new generation.

Otherwise, all local resource zones cleared at $30/MW-day for the summer, $15/MW-day for the fall, $0.75/MW-day for the winter and $34.10/MW-day for the spring. Zone 5 contains local balancing authorities Ameren Missouri and the Columbia, Mo., Water and Light Department. (See *Missouri Zone Comes up Short in MISO's 2nd Seasonal Capacity Auction, Prices Surpass $700/MW-day*.)

Moehn said the cost of new entry prices in MISO Zone 5 are a function of "higher load requirements, changes to the accredited capacity of generation available and reduced import capability."

He said auction results indicate that Ameren Missouri needs to redouble efforts to "execute the generation plans" laid out in its integrated resource planning. The pairing of new, large loads with new renewable generation means that significant transmission expansion is more necessary than ever to maintain reliability, he said.

"We stand ready to work with stakeholders in our region to address the capacity needs," Moehn said. He added that the Ameren Illinois and Ameren Missouri service territories are on track to experience mounting load growth, with new projects proposed from the automotive, aerospace manufacturing, data center and agricultural industries.

Ameren's retiring Rush Island Energy Center — which played a role in the Zone 5 capacity shortfall — also factored into the utility's earnings picture for the first quarter.

Ameren Missouri's Rush Island Energy Center | *Ameren*

Ameren announced first-quarter earnings of $261 million ($0.98/share) compared to $264 million ($1/share) a year ago. CEO Marty Lyons said unseasonably warm conditions in February and March reduced profits, as did expenses related to mitigation relief stemming from Rush Island's unresolved air pollution case.

"Despite the year-to-date weather headwinds and the Rush Island charge, our team is taking steps to contain spending, and we remain on track to deliver within our 2024 earnings guidance range of $4.52 per share to $4.72 per share," Lyons said.

For the rest of 2024, Ameren will implement hiring restrictions, reduce its contractor and consultant workforce and cut back on discretionary spending, Moehn said.

Coal Woes

The company recently filed a plan with the U.S. District Court of Eastern Missouri to remediate 14 years of unlawful air pollution from Rush Island. The $20 million plan involves a surrender of the plant's sulfur dioxide allowances under EPA's cap-and-trade program, distributing air filters to disadvantaged households downwind of the pollution and an offer to purchase 20 electric school buses and 40 charging stations for the St. Louis area.

The U.S. Department of Justice, on the other hand, insists Ameren spend $120 million on a plan including more intensive bus electrification and residential filtration programs. (See *Court: Ameren Still Without Remedy for Years of Rush Island Air Pollution*.)

Ameren expects evidentiary hearings on the matter this summer and the court's decision by the end of the year.

"When you look at the components of the two programs, they are very similar in terms of electric school buses, air filtration program, charging infrastructure. … It really is seeming-

MISO News

ly not a matter of the program mix, but sort of the extent of them and the cost of them. So, we can't predict what mitigation the court would ultimately order," Lyons said.

He added that any penalty will be "nonrecurring and onetime and won't be something that affects ongoing operations or earnings."

The district court last year ordered Rush Island to shut down no later than Oct. 15. Ameren opted to close the plant rather than spend several million dollars to install a flue gas desulfurization system to scrub excess emissions. The Justice Department and Ameren have been at an impasse for two years over how to remediate Rush Island's longstanding environmental harms beyond the plant's early retirement.

Lyons said Ameren is progressing on its request with the Missouri Public Service Commission to securitize the remaining balance of Rush Island, noting that PSC staff in March recommended the company be allowed to securitize $497 million instead of an original request for $519 million. The PSC is expected to issue a ruling in late June.

Lyons cautioned that another Ameren Missouri coal plant, the Labadie Energy Center, faces an uncertain future. While units at the plant aren't slated to retire until 2036 and 2042, they are vulnerable to EPA's new rule stipulating that coal plants either close by 2039 or use carbon capture or other technologies to capture 90% of their emissions by 2032. (See *EPA Power Plant Rules Squeeze Coal Plants; Existing Gas Plants Exempt*.)

Lyons said EPA "expects generators to rely heavily on carbon capture and storage technologies, which are not ready for full-scale economy-wide deployment." He added that the rule's application to new gas-fired units with greater than 40% capacity factors will likely complicate Ameren's plan to add a gas-fired combined cycle plant sometime in the early 2030s to maintain reliability. Litigation by stakeholders is likely, Lyons said.

"While we are still assessing the impact of the rules on our integrated resource plan, these new rules are making it more challenging and costly to maintain existing dispatchable generation or build new dispatchable generation. These challenges come at a time when supply and demand is tight, and the industry has seen significant potential load growth. … These rules, if not modified, would require significant investments beyond what's in our current 10-year pipeline to meet compliance obligations and maintain a reliable system," Lyons said.

Transmission Awards

Finally, Lyons called attention to MISO selecting Ameren to build three competitively bid projects from its first, $10 billion long-range transmission portfolio. (See *MISO Chooses Ameren for 3rd Long-range Tx Project*.) He said the awards provide evidence of the company's "record of being able to deliver cost-effective, high-value projects to our communities."

"Ultimately, Ameren was assigned or awarded approximately 25% of total Tranche 1 portfolio projects addressing the MISO Midwest region and 100% of the projects in our service territory," Lyons said.

Lyons said he expects construction on the projects to "substantially begin in 2026." He noted also that Ameren representatives have been collaborating with MISO planners in "ultimately approving the most appropriate path forward" on the approximately $20 billion in long-range transmission projects proposed in the RTO's *second portfolio*. ■

MISO News

Wisconsin PSC: Missing Info in We Energies' Oak Creek Coal-to-gas Plans

By Amanda Durish Cook

The Public Service Commission of Wisconsin said it's missing several details from We Energies regarding its multiyear plan to substitute gas for coal at its Oak Creek Power Plant south of Milwaukee.

In a May 3 letter, the commission said it and the Wisconsin Department of Natural Resources reviewed We Energies' application for a certificate of public convenience and necessity to build the gas plant and deemed it incomplete. The PSC told the utility it could not make a decision and to re-file an application including the overlooked specifics (*6630-CE-317*).

We Energies intends to retire two of its 60-year-old Oak Creek coal units this month and the remaining two units by December 2025. It has requested to replace the capacity on-site with $1.4 billion in five gas-fired combustion turbines that would generate up to 1.1 GW. The utility applied for the certificate at the beginning of April and expected to have commission approval this month.

The Wisconsin PSC compiled a three-and-a-half-page list of missing or incomplete elements in the application. The agency asked for modeling data supporting the case for the plant, drawings of proposed and alternate layouts, an estimated maintenance schedule, a description of all major construction activities and a breakdown of capital costs. The commission asked We Energies to detail how hydrogen "may be used for any potential future fueling of the proposed combustion turbines."

The agency also zeroed in on how the plant could be affected if the utility's proposed, 33-mile Rochester Lateral gas pipeline is rejected, and asked how the pipeline stands to affect the plant's construction schedule. We Energies *filed* for permission to build the pipeline — which would supply firm natural gas service to Oak Creek — on the same day it requested commission approval to the build the plant.

Oak Creek Power Plant undergoing an expansion in the mid-2000s | *Bechtel*

The PSC asked We Energies to calculate the amount of firm natural gas supply needed to run all five turbines continuously at maximum output and asked if its proposed upgrades to its natural gas infrastructure — alongside ANR Pipeline Co.'s planned capacity expansion in the area by late 2027 — would be enough to support those kinds of operations. It also asked how much a proposed, on-site liquified natural gas storage tank would hold and how long the tank could support the new turbines running at full speed.

The commission said it wanted to know if We Energies anticipates or has factored in additional costs to convert the Oak Creek substation since the new gas plant must connect to the MISO system at different voltages than the existing coal plant. Transmission owner American Transmission Co. is phasing out its 230-kV system in the area and will use only 138-kV and 345-kV voltages, affecting Oak Creek's point of interconnection.

In February, FERC granted We Energies a departure from MISO's interconnection rules so the replacement gas plant can connect to the system at a different voltage without the utility having to submit a fresh interconnection request with MISO. (See *We Energies Secures FERC Permission to Switch Coal Interconnection with Gas Plant*.)

The PSC asked whether We Energies has contacted MISO to perform retirement studies to figure out if the system can operate reliably as the coal units cease production and after Oak Creek's interconnection point is calibrated to different voltages. It said it wanted to know if powering down the four coal units can "proceed as planned without reliability concerns." It also asked whether Oak Creek's generator replacement studies consider only the two immediate coal unit retirements or all four of them.

Finally, the PSC said We Energies submitted an incomplete construction-noise study with its application.

In its application to build the plant, We Energies called Oak Creek's shift to natural gas a "key component" in providing reliability amid its fleet transition, conforming to MISO's stricter resource adequacy rules, meeting growing load and complying with proposed EPA requirements. ■

NYISO News

FERC Approves NYISO Request to Lower NYC Capacity Requirement

By James Downing

| Shutterstock

FERC on May 6 granted NYISO's waiver request to update its installed capacity requirement for New York City in the 2024/25 capability year, which began May 1 (*ER24-1800*).

The amount of capacity the market is set to procure for Zone J (i.e., the city) was off because NYISO originally used the wrong historical data to calculate the transmission security limit (TSL) floor for the zone, from 2017-2021 instead of 2018-2022. The TSL floor is an input for the locational capacity requirement (LCR) and essentially acts as the minimum LCR.

The correct inputs lead to a TSL floor value (and LCR) of 80.4% instead of 81.7%. NYISO told FERC in its request that the waiver would save load-serving entities in the city about $15 million to $20 million per month in capacity costs.

NYISO discovered the issue late and only filed its request on April 18, but it immediately reported the issue to FERC's Office of Enforcement and the ISO's Market Monitoring Unit, Potomac Economics, on April 10, as required by its tariff. The grid operator said it acted swiftly to analyze the error and determine its impact and potential remedial impacts. It is also trying to understand how it happened and avoid it going forward, it said.

The waiver is the narrowest feasible solution to the problem created by the error, NYISO said. Only Zone J needs to be fixed, and the correction would not cause any reliability issues or changes to the reserve margin set for the New York Control Area.

The waiver also addresses a concrete problem by avoiding overcharging consumers in New York City, and it would not have undesirable consequences, such as harming third parties, the ISO said.

"NYISO argues that although the correction may result in lower capacity prices in Load Zone J, which may be contrary to the economic interests of some market participants, no stakeholder has a legitimate interest in preventing an error from being corrected for that reason," FERC said. "NYISO asserts that all market participants will benefit from capacity auction prices that accurately reflect NYISO's methodology for computing transmission security limit floor values for LCRs."

The LCR is also the basis for several downstream processes related to the capacity market, such as the determination of capacity accreditation factors and the availability of capacity import rights, but NYISO said it did not need to fix those issues yet because the financial impacts of doing so would be limited. However, the ISO said it would continue to work with stakeholders to assess the feasibility, implications, timelines and required actions to pursue any corrective actions going forward.

The Independent Power Producers of New York and New York City both said NYISO should work expeditiously to complete the assessment of how other downstream parts of the capacity market might be impacted.

FERC found that the waiver request met its requirements, including solving the concrete problem of avoiding overcharging for capacity.

While some parties argued for additional requirements that NYISO fully address the downstream impacts of its error, FERC said such arguments were beyond the scope of the proceeding. The commission encouraged NYISO to expeditiously complete its assessment of the error's impact and continue working with stakeholders on a solution. ■

PJM News

Following Court Ruling, FERC Reluctantly Reverses PJM Post-BRA Change

By Devin Leith-Yessian

FERC on May 6 partially reversed a 2023 order allowing PJM to modify a parameter for the 2024/25 Base Residual Auction (BRA) to avoid a substantial increase in capacity prices in the DPL South transmission zone and instructed the RTO to rerun the third Incremental Auction (IA) (*ER23-729-002*).

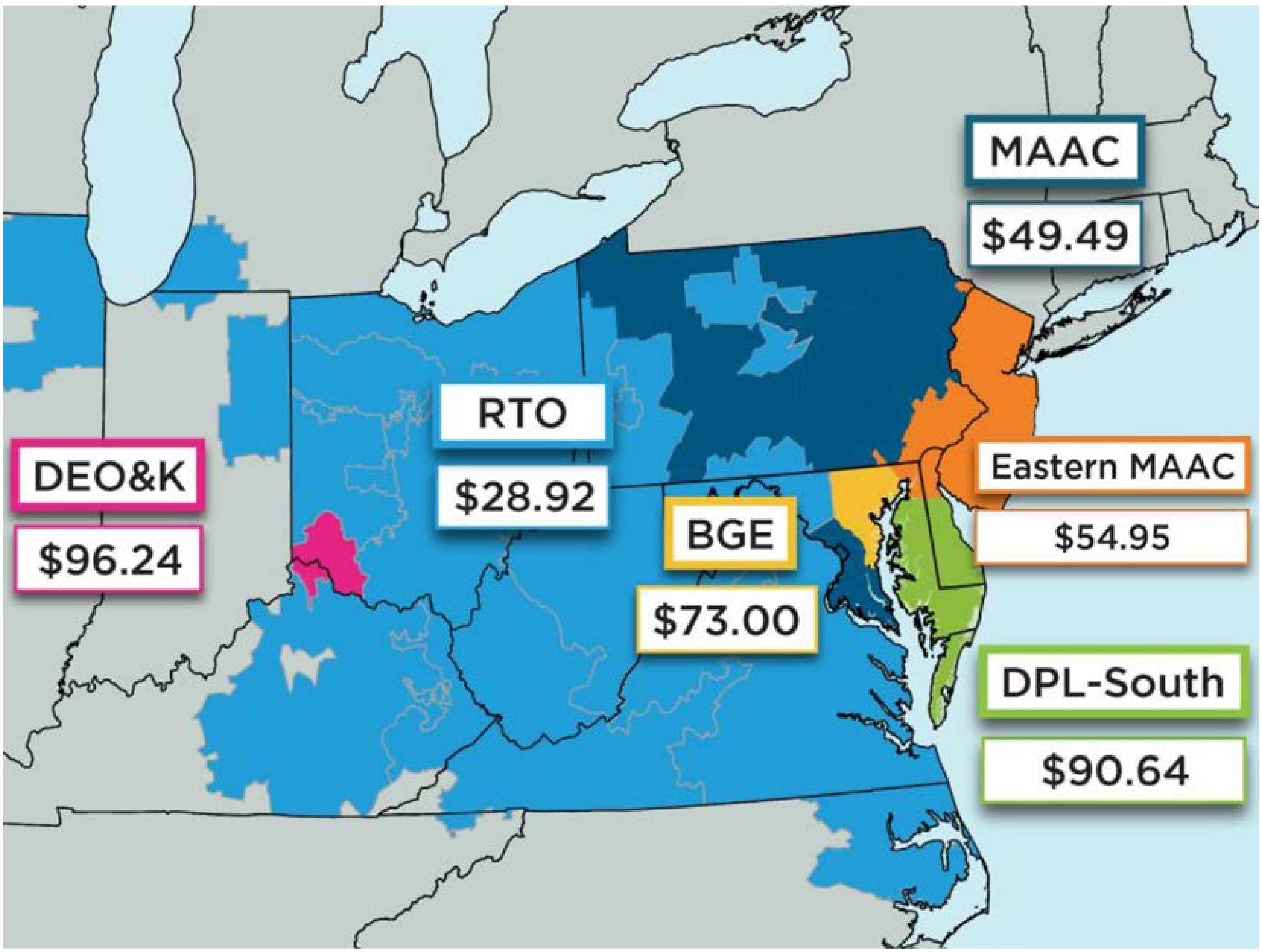
The order increases the clearing price for the DPL South locational deliverability area (LDA) to $426.17/MW-day, up from $90.64 under the auction results PJM posted in February 2023 using the modified parameter. The LDA with the second-highest price is the DEOK region, which cleared at $96.24/MW-day.

In a series of notifications to stakeholders following the order, PJM said it will reopen bids for the third IA on May 10 through May 16; the auction was originally administered Feb. 27 through March 4. Market participants' original sell offers and buy bids will be the default if no changes are submitted, while all bilateral and replacement transactions made since March 4 have been withdrawn by PJM.

FERC had granted PJM the authority to revise the reliability requirement for the zone, which covers the Delmarva Peninsula, after preliminary analysis of the BRA, held in 2022, showed a nearly fivefold increase in capacity prices because of an unexpected shortfall in offers. The change was made after the auction was run but before the results were published.

But in March, following challenges by several stakeholders, the 3rd U.S. Circuit Court of Appeals ruled that change constituted retroactive ratemaking, a violation of the Federal Power Act, as well as the filed rate doctrine. (See *3rd Circuit Rejects PJM's Post-auction Change as Retroactive Ratemaking*.)

The RTO had requested that the commission allow it to exclude resources that did not enter into the auction from the zone's reliability requirement and to add tariff language permitting the parameter to be revised when resources expected to offer into the auction prompt the reliability requirement to increase by more than 1% but ultimately do not submit an offer. The court's ruling and FERC's order leave the forward-looking tariff language but



PJM capacity prices for delivery year 2024/25 | *PJM*

PJM News

require the original reliability requirement to be used for the 2024/25 auction and the third IA.

PJM filed a petition arguing that the only way forward would be for it to recalculate the BRA results using the unaltered reliability requirement and asked the commission to allow it to rerun the third IA. Several state commissions, consumer advocates and industrial groups jointly protested, making a case that FERC holds remedial authority and could direct PJM to continue using the revised parameter.

But FERC said the court had tied its hands.

"We find that the court's opinion vacating the portion of the commission's orders allowing PJM to apply the tariff amendments to the 2024/2025 BRA indicates PJM 'was required to use' the initial LDA reliability requirement," FERC said. "In particular we note that, in reaching that result, the court reiterated that 'the equities play no role in its application of the filed rate doctrine.' Accordingly, while we acknowledge PJM load parties' concerns about rerunning auctions and the equities implicated by this proceeding, we find that they cannot change the outcome here."

Commissioners Reluctantly Concur

All three sitting commissioners separately expressed dismay with the outcome.

Chair Willie Phillips criticized the 3rd Circuit's decision, saying its "broad reading of the filed rate doctrine, and its endorsement of 'predictability' as a higher virtue than equity, is beyond troubling and does not represent my views. ... One must ask: If the over $100 million result of a 'faulty assumption' (and no one in this case argues that it's not a faulty assumption) is somehow OK, what about a $1 billion faulty assumption, or a $1 trillion faulty assumption? Can we still conclude those are just and reasonable rates?"

Phillips urged "all stakeholders, including both PJM and the generators that will reap the more than $100 million windfall due to the court's decision, to take all necessary steps to ensure that we never find ourselves in this position again. That includes putting in place controls to ensure that a similar error does not reoccur and, should it somehow happen again, that PJM or the commission has the authority to correct that error and protect customers from such a manifestly inequitable result. Basic equity, and the public interest, demand nothing less."

Commissioner Allison Clements went a step further, saying that the commission could initiate a proceeding under FPA Section 206 to investigate whether RTOs lacking such protections may produce unjust and unreasonable rates.

"Should PJM and other public utilities fail to affirmatively update their tariffs to provide notice that adjustments can be made, where appropriate, to prevent inequitable outcomes, then it will fall to the commission to cure this failure pursuant to its authority under Section 206 of the Federal Power Act," she wrote.

Her criticism of the ruling was also broader, saying that "it is only the latest in a string of unjust outcomes stemming from the courts' narrow view of [the filed rate] doctrine" and citing a previous *case*. (See *DC Circuit Upholds FERC Ruling on SPP Z2 Saga*.)

Commissioner Mark Christie said "the complexity of PJM's capacity market cannot be overstated" and raises the risk of oversights costing consumers.

He quoted his concurrence from earlier this year in FERC's approval of PJM's changes to its capacity market, criticizing it as increasingly incomprehensible: "Perhaps PJM should be required to post a warning to every reader who tries to read and comprehend a detailed explanation of how the capacity market construct works (borrowing from Dante): 'Abandon all hope, ye who enter here.'" (See *FERC Approves 1st PJM Proposal out of CIFP*.)

"The tinkering and complexities here will assuredly impact consumers — who took no part in this tinkering but will surely pay for the complexities by way of what are estimated to be dramatic rate increases," he said in his latest concurrence. "This ... should require each and every one of us who have played some part in the tinkering (regulators, RTOs and market participants alike) to make certain that it is not consumers who must abandon all hope."

Consumer Advocate Argues More Could have been Done

Maryland People's Counsel David Lapp told *RTO Insider* he believes FERC had the authority to act differently.

"It's extraordinary that we have three FERC commissioners ... acknowledging that this is unfair to customers and customers are being getting hit with the consequences of this error and yet they are not using their authority to address that problem — and they have remedial authority," he said. "FERC is responsible for setting just and reasonable rates; we know the rates are not reasonable, and yet customers are being forced to pay those rates."

Without the power to resolve market design errors before rates go into effect, Lapp said he is worried similar circumstances could arise again. His office will be exploring tariff amendments that could be offered in the stakeholder process to empower PJM to correct issues before they hit consumers' bills.

Lapp noted that the increased capacity costs will go into effect as Maryland ratepayers may be required to pay a share of a $263 million reliability-must-run (RMR) contract to keep the 410-MW Indian River Unit 4 generator online through December 2026. (See *PJM Monitor and Consumers Protest Indian River Compensation Settlement*.)

"This specific impact [from the capacity market] appears to be around $5/month, and there are additional impacts from the RMR for the Indian River plant retirement," he said. "Maryland's customers as a whole are getting hit very hard as a result of the consequences of this error — this error that everyone acknowledges is an error — but also as well as the planning processes, or lack thereof, at PJM."

The Maryland Public Service Commission also criticized the order, arguing it would produce unjust and unreasonable rates, "though we appreciate each of the FERC commissioners' expressed reluctance to have to approve PJM's proposal," spokesperson Tori Leonard wrote in an email.

"Rates will clearly be unjust and unreasonable. We can only hope this could be rectified somewhat, through the Incremental Auction. That is not to say that our commission is not weighing its legal options on this matter," Leonard said.

Independent Market Monitor Joe Bowring said PJM's effort to revise the reliability requirement may not have run afoul of the filed rate doctrine had PJM not sought to create a new rule enshrined in the tariff.

"They didn't have to make it subject to a rule change. ... They could have realized they made a mistake, fixed it and posted the correct numbers," he said.

Bowring said it's unlikely that rerunning the third IA will present participants with technical challenges around preparing new offers, which he said will be carefully reviewed to ensure that participants are not taking advantage of insight into how others behaved in the first iteration.

"It's hard to predict; as always we don't want people exercising market power. ... It gives you an advantage to know what happened," he said. ■

PJM News

Study: PJM Queue Wait Times Contributing to Longer Construction Periods

By Devin Leith-Yessian

Lengthy wait times in PJM's generator interconnection queue are interacting with siting and permitting timelines, supply chain disruptions and inflation to contribute to increasingly long construction periods, according to a *study* released last week by Columbia University's Center on Global Energy Policy.

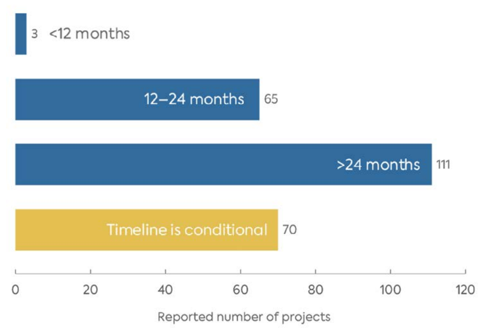
The report, "Outlook for Pending Generation in the PJM Interconnection Queue," surveyed 30 developers with projects in the "advanced stage" of the queue regarding the amount of time it would take for them to reach commercial operations after receiving an interconnection service agreement (ISA) and what major roadblocks could stymie those projects.

"The key finding from the survey is that PJM's increasingly lengthy interconnection process is exacerbating siting and permitting challenges and leading to knock-on delays in equipment procurement and financing decisions, suggesting the timeline for new generation in this market will likely remain long for the foreseeable future," wrote the authors, Abraham Silverman and Zachary A. Wendling. "Given the importance of new entry to keeping prices competitive and maintaining reliability amid the retirement of older fossil resources, PJM will need to find ways to reduce interconnection delays or reconsider when those fossil resources should be retired."

The amount of time for a project to go from design to completion has been increasing over the past five years, the study said, and in PJM, the time it takes for a new interconnection service request to receive an ISA has increased from two years to five.

If they were to receive an ISA today, participating developers said about 1% of the 249 projects they collectively have in PJM's queue would be able to reach commercial operation within a year, while 26% could be completed within two years and 45% would take even longer. Among the 28% of projects with an in-service date conditioned on factors that made completion difficult to predict, siting and permitting was the largest source of uncertainty, along with supply chain constraints and the cost of transmission upgrades.

Because local siting approvals and permits tend to be valid for up to two years, developers said uncertainty around their timelines for receiving an ISA has led many to wait until their interconnection studies have been complete to seek new permits, which can add time to how long it takes projects to get off the ground after PJM has completed its studies.



A study from Columbia University's Center on Global Energy Policy found that the amount of time it takes for generators to clear PJM's interconnection queue correlates to longer construction times. | *Center on Global Energy Policy*

One developer interviewed as part of the study described the interaction between the queue and permitting as "a bit of a chicken-and-an-egg problem: Ideally you would time these things so [permitting and construction] would come together, but until you have some kind of certainty that you are going to get an interconnection, we've been unwilling to make massive spending on permitting."

State regulations and siting requirements can complicate the matter as well, with West Virginia and New Jersey called out by developers for having rules that prove difficult for solar developers to navigate, and local authorities opposed to projects subjecting them to "a never-ending appeals process."

Offshore wind developers said federal regulators desire flexibility around projects' points of interconnection or turbine designs, changes that can trigger PJM to restart the interconnection process.

The study also questioned a central premise of the cluster-based interconnection process PJM embarked on this year: that many developers were submitting multiple interconnection requests for the same project to determine which point of interconnection would result in the least expensive network upgrade allocation. Part of the justification for including increasingly large readiness deposits as proposals progress through the queue was to weed out speculative projects. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

"The extent to which these duplicative requests slow down PJM's efforts to complete interconnection studies has been hotly debated, and several of PJM's recent queue reforms were designed to eliminate them," the study said. "In the sample, only one developer identified an interconnection queue request that had been suspended or paused because it was extremely similar to another project with a separate queue position. Given this issue has been a major theme in PJM discourse, it was surprising to find only a single instance of it among ... all the projects in the survey, though it is possible that developers are unwilling to self-report filing a duplicative or speculative interconnection request."

PJM spokesperson Jeff Shields disputed the report's finding that speculative projects did not contribute to the queue backlog, saying there were 734 projects eligible for study when the RTO began implementing the new study approach last year, 118 of which dropped out or did not meet the new readiness requirements.

He said most of the issues the report laid out are being addressed by the revised process, which has been on pace since implementation began last summer and is expected to clear about 72 GW of generation by mid-2025 and 230 GW over the next three years. The approach is designed to streamline the process for developers and provide more "transparency, certainty and equity," Shields said in an email.

"The delays for new projects are related to the fact that there are such a high number of megawatts in the queue ahead of them. What's more concerning is the 450-plus projects totaling nearly 40,000 MW that have cleared PJM's study process without moving to construction and operation due to siting, financing and/or supply chain challenges not related to PJM's process," he wrote.

Shields said network upgrade costs should pose minimal barrier for the 26 GW of projects sorted into the expedited process, which places proposals in a fast lane if they're allocated less than $5 million in upgrades. ■

PJM Members Committee Briefs

Stakeholders Re-elect 3 PJM Board Members Over Consumer Dissent

BALTIMORE — The Members Committee voted to re-elect three members of the PJM Board of Managers, placing Paula Conboy, David Mills and Vickie VanZandt on the board for additional three-year terms.

Board member and Nominating Committee Chair Dean Oskvig said all three candidates are completing their first term on the board and "hit the ground running" in his experience working with them. Conboy and Mills were first elected to the board in 2021, while VanZandt was appointed to the board in September 2022, following the resignation of board member Sarah Rogers.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), told the MC that several advocates were voting against their re-elections to express frustration and waning confidence with the board's handling of the clean energy transition, market power concerns and the lack of analysis on the cost impacts of transmission.

Poulos also stated there's uncertainty around the functioning of the capacity market and a feeling that the board rushed stakeholders to a vote on proposed revisions to the Operating Agreement and tariff to transfer filing rights over regional planning from PJM's membership to the board.

The MC voted against that proposal May 6 and on May 13 the board issued a notification that it's deferring action until after the May 13 FERC order on regional planning. (See *Members Vote Against Granting PJM Filing Rights over Planning*.)

Because the board tends to speak as a single body, Poulos said it's difficult to discern where individual board members stand on issues and the advocates' "no" votes were not against any of the candidates as individuals, but rather to signify dissatisfaction with the direction the board has taken.

Productive Year of Changes in 2023, Say Asthana and Midgley, Challenges Ahead

PJM CEO Manu Asthana opened the RTO's 2024 Annual Meeting stating the organization has had an exceptionally strong year of reliability and is in the process of implementing market redesigns drafted throughout 2023 to poise PJM to continue performing well.

Changes to the Reliability Pricing Model

PJM Board Member. Dean Oskvig | © *RTO Insider LLC*

(RPM) created through last year's Critical Issue Fast Path (CIFP) process calibrate market signals to the energy transition's new realities, he said. The changes also move ahead on improving generation accreditation, adding sophistication to risk modeling and enhancing testing of generator's capabilities, he added. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

Asthana said the January 2024 Winter Storm Gerri presented many of the same challenging conditions as the December 2022 Winter Storm Elliott, which pushed PJM into some of its most severe emergency procedures and was one of the contributing factors to launching the CIFP process. This time around, however, transmission and generation performance improved, and PJM's load forecasting was accurate in the days ahead of the storm. (See *PJM: 'Conservative Operations' Maintained Reliability During Jan. 2024 Storm*.)

"We learned from the experiences of Elliott, and we saw it come to fruition in Gerri," he said.

PJM also initiated the transition to a cluster-based approach to studying new generation interconnection requests in 2023, Asthana said, setting a goal of completing the fast-track queue this year.

"We're making a lot of process on generation interconnection, which I feel good about," he said.

The acceleration of the clean energy transition is catching the world flat-footed, and more work is needed at PJM, he said. Generation deactivations, new entries and the pace of load growth are surprising, particularly with the introduction of data centers, electric vehicle charging and hydrogen production load, Asthana said. The timing of the transition largely is out of PJM's control and policy tradeoffs likely will be needed but he said discipline and effort in the stakeholder process can reveal solutions.

"There is a lot of work that we still have to get right working together and time is not our friend," he said.

MC Chair Sharon Midgely, Exelon vice president of federal regulatory affairs, said the CIFP changes and a proposed regional planning paradigm will improve PJM's ability to meet rapid load growth and changes in the generation mix. PJM's proposed long-term regional transmission planning (LTRTP) process is being considered by the Markets and Reliability Committee, which deferred a vote April 25 to await the FERC regional planning order. (See "Stakeholders Defer Vote on Long-term Planning Proposal," *PJM MRC Briefs: April 25, 2024*.)

"I am cautiously optimistic that we will see some order of LTRTP implemented at PJM in the short term," Midgley said.

She also highlighted the proposal to transfer Federal Power Act Section 205 filing rights over the transmission planning protocol to PJM, stating PJM will need every tool at its disposal during the clean energy transition. PJM currently is the only RTO that does not have these rights over its planning rules.

Stakeholder collaboration also will need to be centered in PJM's efforts to navigate the transition, she said. "It is incumbent on everyone in the room to work together to ensure reliability through the energy transition."

PJM Panel Discusses Innovation and Technology

PJM held a panel on its efforts to use innovation to find solutions to the challenges posed by climate change, generation interconnection and control-room operations. The panel was moderated by Chief Communications Officer Susan Buehler and featured Chantal Hendrzak, executive director of IT operations and architecture; Dave Souder, executive director of system operations; and Emanuel Bernabeu, senior director of applied innovation and analytics.

As more intermittent resources come onto the grid and weather becomes less predictable, Souder said forecasting needs to look not only at the storms' magnitudes but also their precise timing to understand how weather may

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impact available generation, adding that even thermal resources can be affected by higher water and ambient air temperatures. He said PJM is looking at expanding its data science team to investigate factors such as the impact ice can have on wind turbines, wildfires interrupting solar output and high winds disrupting thermal generators.

Machine learning can be employed in the control room to analyze past outages and the responses taken to determine which solutions may be best employed in real-time operations. During the June 2022 derecho that caused outages in Ohio, Bernabeu said technology could have reduced load shedding by about 20% and allowed grid operators to make critical decisions more quickly.

Hendrzak said AI tends to be limited by its focus on learning from past experiences, but in the context of cybersecurity it can be used to develop a baseline pattern of normal user behavior to detect anomalous activity that could signify an intrusion.

Bernabeu said one of the challenges in using machine learning to improve operations is the infrequency of major events on the grid, increasing the importance of interregional information sharing about outages.

"It's a terrible thing to waste a blackout so I always go and inspect everything about them," he said.

Hendrzak said she foresees a role for AI in the generation interconnection process to aid developers in identifying the best locations to site resources with minimal grid impacts, as well as for PJM to run network upgrade studies in parallel and to identify which projects are the most likely to succeed in reaching commercial operation. Souder said this will become increasingly important as the resource mix changes and it becomes more difficult for transmission owners to take lines down for outages.

From left: PJM's David Souder, Chantal Hendrzak and Emanuel Bernabeu speak at the 2024 PJM Annual Meeting. | *© RTO Insider LLC*

One of the challenges PJM and the electric industry face when integrating new technologies is the availability of data scientists. Out of the hundreds of programs PJM has designed in-house or through contractors, Hendrzak said they tend to be written by the same groups of industry-specialized engineers.

Stakeholders Endorse GDECS Revisions

The committee endorsed a slate of *revisions* to PJM's governing documents recommended by the Governing Document Enhancement and Clarification Subcommittee (GDECS), the most notable of which was changing several references to "end-use customers" to be lowercased. Changes also included removing outdated terminology, grammatical corrections and updating cross references.

PJM Counsel Daniel Vinnik argued the uppercasing of end-use customer in multiple sections related to energy efficiency and demand response was an error and was not meant to limit participation in those programs to PJM members in the End-use Customer sector. He said PJM's implementation of the language has remained the same before and after the uppercasing and noted the formatting was inconsistent throughout the sections.

Paul Sotkiewicz, of E-cubed Policy Associates, said he's concerned about making substantive changes through the GDECS process rather than bringing the revisions through the stakeholder process with an issue charge. He argued that some of the uppercasing may not have been an error, particularly in Schedule 6 language around energy efficiency. ■

– Devin Leith-Yessian

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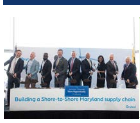

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PJM News

Consumer Advocates, Environmentalists Urge Holistic Thinking at PJM

By Devin Leith-Yessian

BALTIMORE — The Public Interest and Environmental Organization User Group (PIEOUG) discussed costly generation deactivations, RTO versus member filing rights over regional planning and long-term transmission projects with members of the PJM Board of Managers on May 8, the final day of the 2024 PJM Annual Meeting.

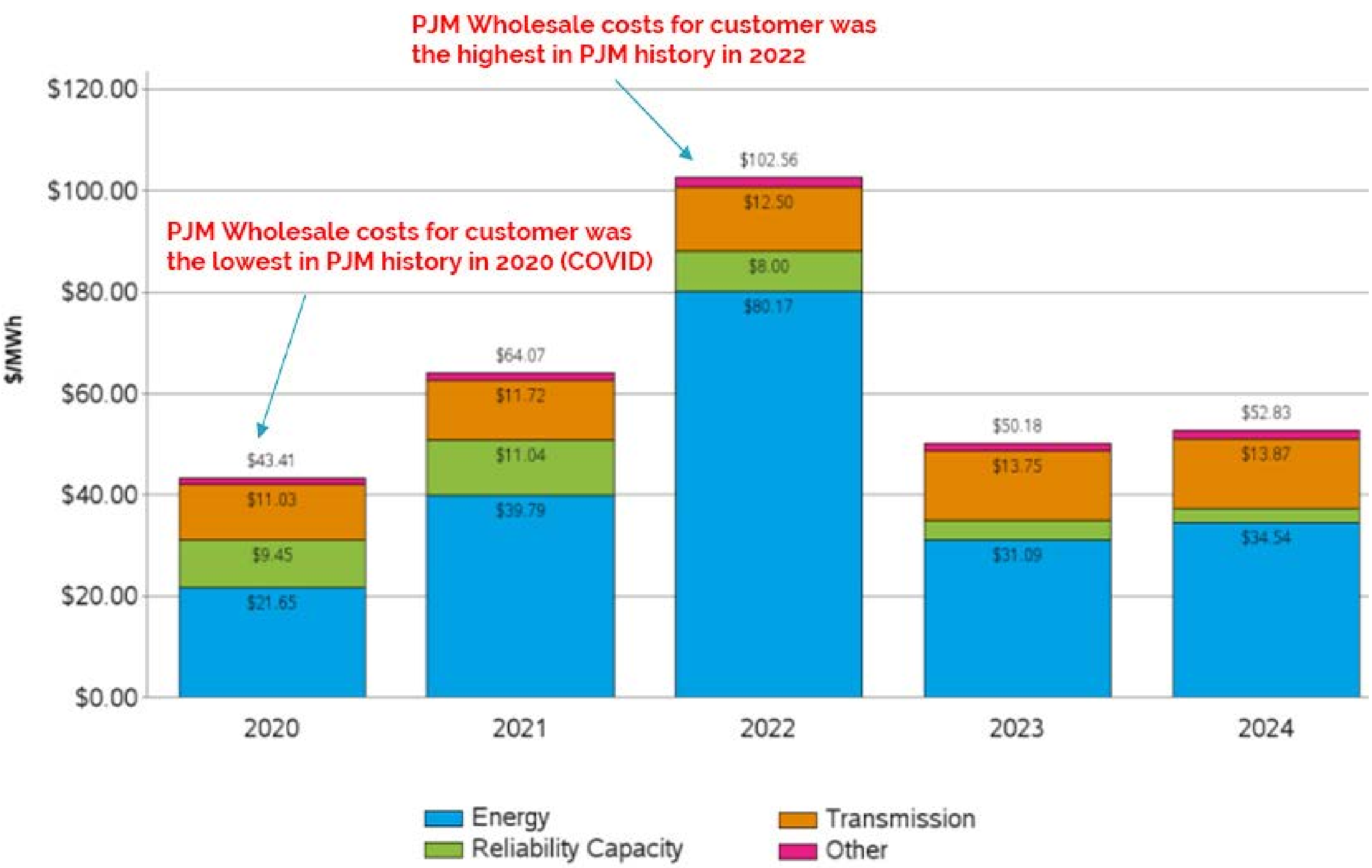
Much of the discussion centered around transmission, how PJM can increase the amount of regional planning it conducts, the cost of utility-designed supplemental projects and a proposal to shift filing rights over the Regional Transmission Expansion Plan (RTEP) from the Members Committee to PJM's board. (See *Members Vote Against Granting PJM Filing Rights over Planning*.)

Ari Peskoe, director of the Electricity Law Initiative at Harvard University, argued that proposed revisions to the Consolidated Transmission Owners Agreement (CTOA) to grant PJM sole filing rights over the RTEP under Federal Power Action Section 205 include language that would allow TOs to supplant PJM-initiated projects with more expensive plans introduced by utilities and would create a "shadow governance" where CTOA signatories could challenge PJM prospective Section 205 filings, PJM regional plans, or other PJM actions through a confidential mediation process.

Peskoe argued the CTOA revisions to allow utilities to declare their intention to build a similar project as one in the RTEP could interact with existing tariff language prohibiting PJM from "planning a duplicative project" to force PJM to remove components from its plan without consideration of the merits of each proposal or whether they are likely to be built. Following the PIEOUG meeting, he submitted a *letter* to the board recounting his comments.

"The CTOA creates new veto powers and broad rights of first refusal, as well as new opportunities for each utility to interfere with regional planning, PJM's FERC filings and other PJM actions. The new CTOA also subjugates PJM's RTO status to the CTOA, reduces transparency for PJM members and states, and limits PJM's options as it navigates the energy transition. It would create a new shadow governance system where utilities will have the advantages," he said in the letter.

The MC overwhelmingly rejected corresponding revisions to the PJM Operating Agreement and tariff to transfer filing rights May 6, which several members argued were being rushed through the stakeholder process and could lead to PJM being able to make unilateral economic determinations about the viability of generators. The transfer would



Consumer advocates spoke about the growing role transmission costs play in driving consumer rate increases during the 2024 PJM Annual Meeting. | *PJM*

PJM News

require revisions to both the CTOA through the agreement of the Transmission Owners Agreement-Administrative Committee (TOA-AC) and the PJM board, as well as the amendment of the OA and tariff. The board notified stakeholders May 10 it's deferring deciding on the CTOA revisions until after the FERC filing on long-term transmission planning, noting the MC's rejection of the changes.

Attorneys representing transmission owners supporting the CTOA revisions responded to Peskoe's comments in a May 9 *letter* to the board, stating the changes would not empower TOs to remove PJM-selected projects from the RTEP in lieu of their own, but rather would allow them to continue to move forward with projects at the risk of FERC finding them imprudent.

"Nothing prevents PJM from continuing with the RTEP project," the letter states. "PJM is obligated to go ahead with the regional project. If any change occurs, it would be PJM revising its project to address the Transmission Owner project need, in which case the risk would be on the Transmission Owner to move forward with its project, as outlined above."

The TO letter also states the new mediation process is similar to those approved by the FERC in the past and would allow PJM or TOs to be party to a complaint to dispute the results at the commission.

Consumer Advocates Call for More Holistic Thinking at PJM

Brian Lipman, of the New Jersey Division of Rate Counsel, *said* the number of stakeholder meetings and the pace at which consequential topics are discussed can make it difficult for consumer advocates to stay engaged. His concern about timing extends to the Base Residual Auction (BRA) schedule as well, which has been compressed from its usual three-year advance cycle to allow multiple market changes to be implemented. He said running auctions in close succession increases the odds of errors being introduced, as he said happened with the results of the 2024/25 BRA for the DPL South zone, where FERC ordered PJM to recalculate the results using parameters that caused a substantial increase in prices. (See related story *Following Court Ruling, FERC Reluctantly Reverses PJM Post-BRA Change*.)

"It's so important that we make sure that PJM is not making mistakes ... the timing, the rushing makes us nervous," he said.

Lipman said the advocates' outside position in the market and planning processes make it difficult for them to receive and analyze data about the drivers behind costs faced by consumers. Generation and transmission owners hold data about their assets and operations that can be difficult for advocates to request, even when it is shared with PJM.

Board Member Vickie VanZandt said determining the most reasonable cost requires breaking down silos and holistic solutions, but that transmission owners are best placed to understand the condition of their infrastructure. She questioned how the advocates view where supplemental projects fit into risk management.

Lipman responded that TOs look only at their own assets, whereas PJM can consider regional solutions that could meet the needs of multiple supplemental projects at a lower cost. However, it does not factor local transmission issues into its RTEP proposals.

"We're losing those opportunities, and frankly, they're costing ratepayers a significant amount of money," he said.

Environmentalists Call for More Flexibility Around Deactivations

Casey Roberts, of the Sierra Club, *said* PJM's lack of a proactive plan for replacing retiring resources is missing opportunities to improve the reliability and flexibility of the grid, speed the development of clean energy and save consumers money. She said deactivating generators tend to be older and have lower capacity factors that contribute to them receiving capacity market signals that they no longer are needed for resource adequacy. By holding onto those resources through RMR contracts to resolve transmission violations, she argued the reliability of the grid is dependent on resources that themselves are less reliable. (See *PJM Rejects Storage as Alternative to Brandon Shores RMR*.)

Generators operating on RMR contracts also prevent the redeployment of transmission capability, slowing the pace of new generation coming online, including those that might resolve the same violations necessitating the RMR contract.

She said a study conducted by Gridlab and Telos Energy looking at the feasibility of installing an 800-MW battery at the point of interconnection of the 1,295-MW Brandon Shores found that storage paired with transmission upgrades could resolve the violations at a lower cost than PJM's solution. And it would replace a 40-year-old coal generator with a battery boasting a quick ramp rate and other parameters that thermal generators may lack.

Introducing alternatives to operating generators on RMR contracts while lengthy transmission projects are completed would require a mechanism for CIRs to be transferred to new resources, a longer notification period for generation owners seeking to take units out of commission and TOs working grid-enhancing technologies (GETs), such as dynamic line ratings (DLRs), into their solutions.

Katie Siegner, of RMI, said FERC has made clear that its Order 2023 on generator interconnection should be seen as a floor by RTOs and encouraged PJM to not simply comply with its requirements. She said incorporating GETs into the network upgrade studies performed by PJM and developers for new resources could speed the entry of renewable resources and save customers $1 billion annually by reducing transmission congestion and integrating lower-cost resources onto the system. (See *RMI Report: GETs Could Speed Renewable Development, Save Consumers Billions*.)

Nick Lawton, of Earthjustice, said development of clean energy, deactivation of fossil generation and transmission planning are intricately linked, but are viewed through siloed stakeholder processes. He said about 5% of the energy produced in PJM is generated with renewable resources, while other regions are far ahead.

"It's hard for me not to conclude that PJM is behind," he said, adding that means the RTO doesn't need to reinvent the wheel because the success of others shows the path forward.

Lawton also argued the backlog of proposed generation projects in the interconnection queue has contributed to the slow pace of new entry in PJM and urged staff to continue improving the cluster-based approach the RTO initiated this year. (See *PJM Initiates Transitional Interconnection Queue*.)

"PJM can make the energy transition work but the pace of the transition depends on how quickly PJM acts," he said.

Board of Managers Chair Mark Takahashi said about 40 GW of generators have cleared the interconnection queue and have signed interconnection service agreements (ISAs). Most are renewables, but they haven't yet moved to construction.

Lawton responded that in many cases, the amount of time it took resources to receive an ISA affected their ability to hit the ground running once it arrived, particularly because of changing economic conditions. ■

PJM News

PJM General Session Covers Risk Management, Innovation

By Devin Leith-Yessian


Arushi Sharma Frank, principal of Luminary Strategies, speaks during the 2024 PJM General Session. | *© RTO Insider LLC*

BALTIMORE — Panelists during the General Session at PJM's Annual Meeting last week focused on the evolving security and climate risks the electric industry faces, as well as the potential for technology and a culture of creativity to provide new solutions.

Delivering the keynote speech, Elisabeth Braw, senior fellow at the Atlantic Council's Scowcroft Center for Strategy and Security, said hostile geopolitics are clashing with a globalized economy, putting companies across the world at risk of being caught in the crossfire.

Because cybersecurity threats are now global and often have more to do with national policies than the actual targets, she said individualized efforts at preparation can only go so far. Instead, she recommended organizations work together to identify vulnerabilities and share strategies.

That coordination should often include the public as well: One mistake Braw said many working in critical infrastructure make is being too tight lipped about the risks they face and their mitigation efforts. She pointed to the cyberattack that interrupted Colonial Pipeline operations in 2021, saying the impacts of the attacks were manageable but that an underinformed public began panic-buying gas and compounding constraints on the pipeline.

Braw was joined on a panel about the intersection of risk management with national and world events by NERC Vice President Manny Cancel and Paul Williams, president of the Electric Infrastructure Security (EIS) Council. The panel was moderated by PJM Chief Risk Officer Carl Coscia.

Cancel said joining a regional information sharing and analysis center (ISAC) can allow smaller organizations, such as municipal electric providers, to develop the broad expertise and awareness that large utilities often hold.

Williams said resilience is possible only through working with the communities an organization is part of. Understanding what services are most important to customers, and which business functions are needed to maintain those services, is key. As the former head of the Bank of England's Operational Risk and Resilience Division, he said ATMs may seem like a core need, but what is truly important to users is access to cash — an understanding that creates opportunities for building resilience even if ATM networks are disrupted.

Turning to climate risks, Cancel said the largest challenges are the siting, permitting and interconnecting of new generation and harmonizing the clean energy transition with reliability needs.

Maintaining the infrastructure the grid requires now and throughout the transition will require honest conversations with the public about what the costs will be, Williams said.

Innovation Potential and Challenges

Another panel on applied innovation largely focused on the double-edged sword of the rising capabilities of artificial intelligence.

Jonathan Glass, acting deputy director for commercialization at the U.S. Department of Energy's Advanced Research Projects Agency – Energy (ARPA-E), said AI could speed research into new storage and generation technologies — as well as improve the process for interconnecting them — but the electric industry will first need to get over the hump of rapidly increasing load growth over the next few years as data centers come online.

Arshad Mansoor, CEO of the Electric Power Research Institute (EPRI), said AI development is in the "first mile of a marathon" that could see unprecedented load growth over the next few years, potential business that could flow to other nations if the electric sector cannot keep up. He said the next three to four years will be the most important in laying that groundwork, which will have to involve expanding load flexibility while new generation and transmission are built.

"The country, the region that can power this infrastructure will win the AI race," he said.

Mansoor said there's a disconnect between the personnel working in the electric industry and on the data center side and that more understanding between the two is needed. Forecasting data center demand is constantly changing as computational needs increase and breakthroughs are made in the efficiency of hardware.

Consumer behavior also could be part of the solution, said Arushi Sharma Frank, principal of Luminary Strategies, such as creating virtual power plants using electric vehicle batteries, home storage systems and smart meters to reduce load during peak periods and shift it to more economical times.

Perfecting such technologies will require creative thinking and data analytics skills, Frank said, a pairing that is in demand across industries. Loosening regulations around hiring and immigration could allow individuals working overseas to contribute. ■

SPP Board of Directors/MC Briefs

CEO Sugg Warns of 'Serious Challenges' Facing the Region

AURORA, Colo. — SPP CEO Barbara Sugg warned the RTO's Board of Directors and stakeholders last week that the grid operator faces new and stronger headwinds, even as it met its corporate goals' first-quarter milestones.

In delivering her president's report to open the May 7 quarterly meeting, she said, "I tell people all the time what a great time [it is] to be in the electric utility industry, but it's not without challenges."

Sugg then listed those challenges: "significant" load growth in recent years and more "unprecedented" growth in the foreseeable future; still more variable energy resources in the generation fleet and interconnection queue; the transition to clean energy resources outpacing the technologies needed to support them for reliability; performance issues with traditional resources that have historically been "extremely dependable and responsive"; transmission constraints; struggling to get new transmission built in a timely fashion; and a backlog of generators with interconnection agreements that are not yet online.

"And if that wasn't enough, extreme weather events are becoming more the norm than the exception," Sugg said. "I say all this to say that what got us here will not get us there.

"We're facing serious challenges in the region. We must continue to work together to not only understand these challenges, but remain committed to resolving them."

SPP's corporate goals are tied to its strategic plan. Mitigating resource adequacy risks is tied for the No. 1 goal with cybersecurity, and no wonder: The grid operator has already issued five resource or conservative operations advisories since early March, the latest because of threats from solar storms.

The RTO's other goals are enhancing extreme weather event readiness, optimizing the generator interconnection queue's processing, advancing innovative transmission policies and continuing the western expansion.

"A vital element of these goals is to focus on affordability," Sugg said. "We are still looking for opportunities to increase value and decrease costs. … We are below budget so far this year. I'm knocking on wood in large part due to process improvements and exceptional negotiating skills. Of course, there are always things that come up throughout the year that may or may not have been on our radar or in our budget, but we're keeping a focus on affordability."

SPP's Board of Directors opens its May meeting. | *© RTO Insider LLC*

As if to emphasize the complexities ahead for SPP, the U.S. Department of Energy on May 8 released a list of 10 proposed transmission corridors that could be eligible for a share of $2 billion in federal loans and special permitting under FERC's backstop siting authority. (See related story, *On the Road to NIETCs, DOE Issues Preliminary List of 10 Tx Corridors*.)

Most of the *National Interest Electric Transmission Corridors* (NIETCs) lie squarely in SPP's current and planned footprints. They include the 645-mile Delta Plains and 780-mile Midwest-Plains corridors, both of which would link with MISO. The Northern Plains corridor could solve congestion issues in the Dakotas and Nebraska, while two more in New Mexico and Colorado could improve ties between the two major interconnections.

FERC on May 13 will unveil its plan to accelerate long-distance transmission line development to meet rising power demand and bring a backlog of planned clean energy projects to the grid.

Apparently, it's nothing SPP can't handle. The grid operator says that it will evaluate the order, DOE's NIETC notice and other "pertinent" rulings in coordination with its members and the Regional State Committee, which comprises state regulators.

"SPP is hopeful these initiatives will align with our strategic goals to continue removing the generator interconnection backlog and developing a long-range consolidated planning process," spokesperson Meghan Sever said.

Bylaw Changes for RTO West

SPP's membership unanimously approved recommended bylaw changes from the Corporate Governance Committee related to the RTO's western expansion and board compensation during a special member meeting.

The CGC said the revisions to SPP's bylaws and its membership are necessary to expand the RTO into the Western Interconnection. They include increasing the Strategic Planning Committee's membership, considering diver-

SPP News

sity between the two interconnections when selecting organizational group participants and expanding terms specific to the Western Area Power Administration's Upper Great Plains to the agency's other regions.

Separately, the board approved a package of 16 tariff revisions that include establishing a Western balancing authority area and managing transactions across the DC ties' 510 MW of bidirectional capacity between the two interconnections. Settlements will be based on transmission service reservations during the market's first four years. After that, they will be based on transmission congestion rights.

"We will use a single-market optimization using these DC ties to bring value across both the West and the East, with the goal to bring price convergence across the DC ties," said Bruce Rew, SPP's senior vice president of operations.

Lloyd Linke, WAPA-UGP's regional manager, abstained from the Members Committee's unanimous vote, saying he "fully supports" the changes but that the agency wants to keep its options open in addressing potential protests at FERC.

American Electric Power, Evergy and the Natural Resources Defense Council's Sustainable FERC Project also abstained.

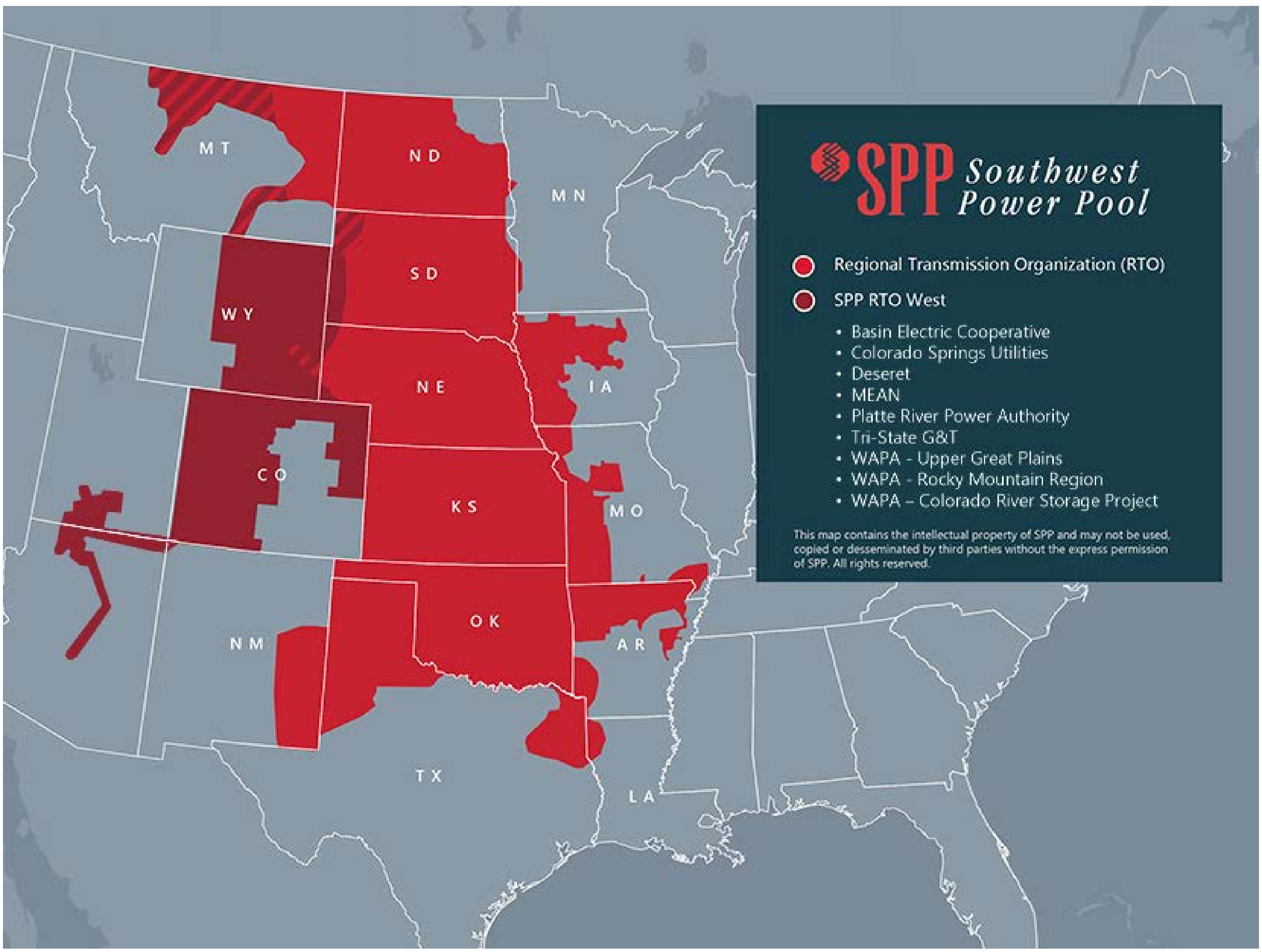
SPP has been working since 2020 with Western parties, some already members in the East, interested in joining the RTO: Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power, Municipal Energy Agency of Nebraska, Platte River Power Authority, Tri-State Generation and Transmission Association, and three WAPA divisions.

The prospective members would add Utah and Arizona to SPP's 15-state footprint.

SPP's RTO West is a "true expansion," in the words of board Chair John Cupparo. Markets+ is a contract service funded by its participants. RTO West is targeted to go live in April 2026.

The approved bylaw changes for directors' compensation will increase their annual retainer from $95,000 to $125,000. The CGC said the increase keeps SPP's board compensation competitive and helps attract top talent.

The committee said it slightly modified the compensation framework to eliminate fees paid for special board assignments, board advisory or liaison support, assigned meetings, and the board/committee meeting fee. Board members will receive additional fees for participating on nine committees and task forces,



SPP's current and proposed RTO footprints. | *SPP*

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increasing their compensation by 6 to 15%.

Sugg said the board's total 2024 compensation of $1.54 million is 11% above forecast. She said a compensation consulting firm recommended an even greater increase.

"You all are very well aware and witness on a near-daily basis just how engaged the board is and how collaborative they are and working with all of you," she told stakeholders.

The CGC will again review the compensation policy in 2025, Sugg said.

SPP, SPS Reviewing April Outage

Sugg told the board and MC that SPP is reviewing a small, local load-shed event in New Mexico and will bring a full report to the Markets and Operations Policy Committee's meeting in July.

The April 28 outage lasted for about two hours and represented about 3% of the area's load. Southwestern Public Service, the local transmission owner, said about 1,000 customers were without power.

"As with all operational events, we take these very seriously and are working through the after-action steps," Sugg said. She said SPP and SPS staff, along with the Operating Reliability Working Group, are involved in the review.

SPS said in a statement it was directed to reduce load to address voltage issues in the southern portion of its service territory.

"The specific drivers behind this event and steps to minimize recurrence remain a topic of discussion between SPS and [SPP]," it said.

2023 Annual Report Released

SPP has released its *2023 annual report* highlighting the previous year's accomplishments, which resulted in $3.6 billion in benefits to its members and a 20:1 cost-to-benefit ratio. Sugg said lower gas prices, "substantial" load growth and an increase in wind energy were the primary drivers.

Using a calculation vetted several years ago by stakeholders, the grid operator found members realized $2.25 billion in benefits from the markets and a combined $1.88 billion from transmission and operations and reliability. That was partially offset by $524.6 million in the transmission revenue requirement's costs.

"We certainly are delivering significant value to the region," Sugg said.

Dowling, Janssen Leave SPP

Sugg led standing ovations for Midwest Energy's Bill Dowling and Kelson Energy's Rob Janssen, who were both attending their last board meeting.

Midwest Energy's Bill Dowling (left) and Kelson Energy's Rob Janssen share a final moment together after their last board meeting. | *© RTO Insider LLC*

Dowling has announced his retirement, and Janssen's company is selling off its interest in Dogwood Energy, a 665-MW gas-fired generator in Oklahoma that serves as its only resource in SPP.

"Lots of people come and go from this committee, but we would be remiss if we didn't stop and recognize the fixtures, those people that really helped us become the organization that we are," Sugg said. "We'll miss both Bill and Rob."

Dowling and Janssen have both served as MOPC's chair and spent more than 20 years on the MC. Dowling was also a founding member of the Regional Tariff Working Group.

"I asked [Bill] if I could blame him for the 8,000 pages in our tariff, and he said, 'No. Only the first 3,000 pages,'" Sugg said.

Board Approves RSC Revisions

The board and MC approved three RSC revision requests that commissioners previously endorsed unanimously — as they did for all seven of their voting items — during their May 6 meeting:

- *RR607* implements policy changes to the safe harbor provisions approved last October to provide more flexibility for market participants. The measure replaces the original 125% peak load criterion to not exceed the transmission customer's projected system peak responsibility multiplied by the higher of 125% or the sum of 110% and the current planning reserve margin percentage. The policy reflects SPP's recent establishment of a PRM.
- *RR605* defines an authorized outage, adds requirements for resources' availability during both the summer and winter seasons (unless on an authorized outage), and helps load-responsible entities and generation owners better understand when to submit RA capacity when providing workbooks to meet the RA requirement.
- *RR616* ensures any outage not approved by the SPP balancing authority and not an outside management control event is accounted for in performance-based accreditation. Three renewable energy interests abstained from the MC advisory vote, with the Sustainable FERC Project's Christy Walsh expressing concerns over SPP's "piecemeal" approach to RA that could lead to additional tariff filings at the commission.

The board's consent agenda resulted in the approval of the 18-person industry expert pool that will judge bids for competitive projects within the SPP footprint. A panel of three to five experts will be chosen from the pool for each competitive upgrade. Sixteen of the members were renewed, and two new members were added.

Other items on the consent agenda included:

- *RR555*, which implements two recommendations FERC made to SPP after the 2021 winter storm: that transmission operators and balancing authorities include new guidelines in their emergency operating plans to facilitate rotating load shed and protect critical gas infrastructure.
- an out-of-cycle request by Evergy Kansas Central to re-evaluate a 138-kV terminal upgrade near Wichita.
- withdrawing a WAPA-UGP 345/230-kV transformer project in Fort Thompson, S.D. WAPA's estimate of $59.17 million exceeded the $36.34 million variance bandwidth and would have delivered the project 10 years late.
- approval of a $35.95 million refined cost estimate for SPS' Potter County 345/230-kV transformer project. SPS' estimate exceeded the $35.91 threshold, but staff said approving the economic project will allow the company to proceed and economically benefit the region. ■

— Tom Kleckner

SPP Regional State Committee Briefs

FERC's Christie Lauds State Regulators, RSC

AURORA, Colo. — FERC Commissioner Mark Christie, who still refers to himself as a state regulator after 17 years on the Virginia State Corporation Commission, offered words of praise and encouragement for SPP's state regulators in his first appearance before the RTO and its Regional State Committee.

"I've always been very admiring of this RSC structure," Christie told the RTO's regulators and stakeholders during the RSC's May 6 meeting. "I'm pleased to be here watching the action of this committee I've heard about for 20 years now that I've been so envious of.

"Your job is incredibly important. I'm obviously very adamant about the state role of RTOs. Someone once told me, 'You're like a state regulator on loan to FERC,' so I'll take that," he added. "But I'm adamant about the state's role because I'm adamant about protecting consumers. Everything that as a state regulator we do, and you all on the front lines, should be about putting consumers first."

As most of the state commissioners that constitute the RSC listened attentively, Christie described resource adequacy as the key element of grid reliability, one of two major issues facing state regulators.

"Resource adequacy means what generation resources will get built, which ones get retired," he said. "You — I should say, we — at the state level are on the frontlines because you're the ones who are approving the construction of new generating resources. You're the ones who are overseeing retirements. That's why your role is actually the most important in the whole regulatory universe."

Christie said the second major issue facing state regulators is consumer confidence because they're "on the front line of rising power prices."

"They're going up, and they're going up at a higher rate than it was 10 years ago," he said. "When you approve a rate increase, and I know this from 17 years of having been a state regulator, it's going to go right into people's monthly bills. That's one thing about being a state regulator is that you hear about it. You live among the people who you're impacting, and that's why state regulators are so important. I trust you all to know what is best for your state."

The feeling was mutual. RSC President John Tuma of Minnesota thanked Christie for attending, saying: "We still welcome you as a full state commissioner, ever though you carry that other title."


RSC President John Tuma honors ex-Texas PUC Commissioner Will McAdams for his service. | *© RTO Insider LLC*

RSC Celebrates 20 Years

The RSC's agenda, which included the quarterly stakeholder briefing, was scheduled for four hours. It went three-plus. Credit Tuma, who ran a tight ship that shaved off more than an hour of discussion. "Today may be a new land speed record," cracked John Cupparo, SPP's board chair.

The early finish allowed attendees to begin their *commemoration* of the RSC's 20th anniversary 45 minutes early.

"I can't believe it's been 20 years for the RSC," CEO Barbara Sugg said. "There's lots for us to celebrate."

"As someone who spent a good chunk of their career in the non-RTO West and experienced regional issues and trying to pull together participation from the regulatory community and others, this is a very challenging effort," Sugg said. "That continues today. From that experience, the RSC group that we have is a special and powerful thing."

The Advanced Power Alliance's Steve Gaw was the only one of the RSC's original six founding members present for the event. A Missouri regulator at the time and also involved in standing up the Organization of MISO States, Gaw said both groups first had to determine how much legal authority they had.

Former FERC Chair Pat Wood's *standard market design*, released after the 2003 Northeast blackout, helped set some guardrails for future RSC members. It took about 18 months for the group to agree on the committee's bylaws and its responsibilities.

"The key to the success of these groups has been about … collaboration and about building bridges and being dedicated [to] trying to find a way to work together to come up with things that would produce a positive result," Gaw said. "If the commissioners had gone with an attitude of saying, 'I have to have my state's interest and it's … the only thing that I'm in here for,' nothing would have ever moved forward."

SPP credits the committee with developing and implementing funding mechanisms that have helped build more than $12 billion of transmission lines since 2006; producing policies governing cost allocation for upgrades facilitating the integration of more than 33

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GW of wind energy in the region; and for its role in helping refine resource adequacy methodologies.

"When the RSC was formed, critics questioned whether representatives of such a diverse group of states could reach consensus on anything," SPP general counsel Paul Suskie, the RSC's staff secretary, said in a *news release*. "For more than two decades, the group has navigated complex challenges, fostered innovation in our industry and contributed to the resilience of an electric grid that serves millions of customers across the central United States."

REAL Team Work Approved

Despite the shortened meeting, the RSC still approved several revision requests, including two brought forward by its Resource and Energy Adequacy Leadership (REAL) Team. Both passed unanimously, as did all seven of the committee's voting items.

The tariff changes, *RR605* and *RR616*, were approved by the Markets and Operating Policy Committee in April. They are the result of RSC directives last October to clarify resources must be available if they're going to be accounted for in the resource adequacy construct and in some load-responsible entities' accreditation.

RR605 would define an authorized outage and criteria, add requirements for resources' availability during both the summer and winter seasons (unless on an authorized outage), and help load-responsible entities and generation owners better understand when to submit resource adequacy capacity in providing workbooks to meet their obligation. RR616 would ensure any outage not approved by the SPP balancing authority and not an outside management control event is accounted for in performance-based accreditation.

The RSC also endorsed the REAL Team's price-formation policy to dispatch resources based on the true obligation and price of the system using the obligation without the impact of the load shed and emergency energy assistance. The policy protects resources that hold day-ahead positions.

South Dakota's Kristie Fiegen, who chairs the REAL Team, said it is close to approving a winter planning resource margin and a fuel assurance policy. Both should be coming to stakeholders, regulators and staff during their July and August meetings. (See *SPP, Members Close in on Fuel Policy, Base PRM*.)

"We've had a lot of policies, but [the winter PRM] is the most time-consuming," Fiegen said.

FERC Commissioner Mark Christie visits with SPP's David Kelley (left) and Paul Suskie. | *© RTO Insider LLC*

The REAL Team has spent six months on the PRM tariff revision, but it's had its side effects.

"I feel like we've become a family this past year," she said.

"Chair Fiegen has done a wonderful job leading these family discussions of the REAL Team," COO Lanny Nickell said. "We haven't yet evolved into a food fight, so that's a good thing."

JTIQ NTCs Possible This Year

Casey Cathey, SPP's new engineering vice president, told the RSC that staff hopes the Board of Directors will issue construction permits by year's end for the five projects in the Joint Transmission Interconnection Queue.

SPP and MISO staffs and potential transmission owners are pursuing a direct billing approach that would require SPP to modify a revision request (*RR620*), which would implement RSC-approved cost-allocation policies for JTIQ projects. MOPC delayed taking action on RR620 during its April meeting.

"We need to ensure we have the revision request locked up," Cathey said, noting staff determined its current approach would be the most efficient way to administer the JTIQ settlement process.

SPP and MISO have agreed to assign 90% of the JTIQ portfolio's $1.06 billion in costs for its five projects to generation. Load will cover the remaining 10%. (See *MISO, SPP Propose 90-10 Cost Split for JTIQ Projects*.)

RSC Welcomes Missouri's Hahn

The committee welcomed Missouri's Kayla Hahn, who chairs the state's Public Service Commission, as its 47th member over the past 20 years and honored the service of recent RSC members Will McAdams (Texas) and Scott Rupp (Missouri).

Two potential future members also were present for the meeting: Mary Throne, chair of the Wyoming PSC, attended in person, while Utah Commissioner John Harvey listened in virtually.

"We look forward to your participation in the RSC and Wyoming's participation in the RSC as part of the RTO West expansion into the Rocky Mountain area," Sugg told Throne.

Wyoming is one of four states that, with Colorado, will make up much of SPP's RTO footprint in the Western Interconnection. Arizona and Utah will increase the grid operator's footprint to 17 states. ■

— Tom Kleckner

Company Briefs

GM to End Production of Chevy Malibu

General Motors on May 8 said it will end production of its gas-powered Chevrolet Malibu car later this year to produce new electric vehicles.

The automaker also announced it is investing $390 million at its Kansas assembly plant to build Chevrolet Bolt EVs.

More: *Reuters*

Rivian Loses $1.45B in Q1

Rivian on May 7 announced it lost $1.45 billion in the first quarter of this year.

The EV manufacturer brought in $1.2 billion in revenue, coming in just under its record haul from the prior quarter, according to its first-quarter earnings report. Rivian's revenue grew 82% from the $661 million it generated in the first quarter of 2023.

Still, the company's shares fell more than 4% during after-hours trading.

More: *Tech Crunch*

Green Energy Production in Italy Boosts Enel's Q1 Results

Italian utility Enel on May 9 said its first-quarter profits rose 12% year-over-year driven by a strong recovery in Italian renewable energy production.

Enel's Italian business benefited from both a recovery in hydroelectric production and growth in its generation and trading business. The performance of its grids business was slightly up year-over-year.

More: *Reuters*

Federal Briefs

FERC Approves Cape Cod Canal Water-powered Turbines Test Site

Marine Renewable Energy Collaborative, a nonprofit promoting sustainable development of renewable energy in New England waters, secured an 8-year pilot license from FERC on May 10 to test prototypes of turbines that harness tides to create energy.

The testing will be done in the Cape Cod Canal at the Bourne Tidal Test Site. Any energy produced will be transmitted to ISO-NE by way of Eversource substations. The Bourne test site was installed in 2017 and has been providing a platform for testing standalone, small-scale tidal turbine prototypes and other marine-related technologies under a permit from the U.S. Army Corps of Engineers.

More: *Cape Cod Times*

TVA Board Asserts Power to Overhaul CEO's Salary

At its quarterly meeting May 10, the Tennessee Valley Authority Board of Directors unanimously approved changes to its compensation plan increasing its oversight and bringing CEO payouts in line with other TVA executives.

TVA CEO Jeff Lyash's total income, which reached $10.5 million in 2023, makes him the highest-paid federal employee. His pay is about 29% less than the median CEO at peer energy companies, according to the TVA board. The board denied Lyash a raise and docked executive payouts in November in response to TVA's first rolling blackouts during a December 2022 storm.

More: *Knoxville News Sentinel*

Report: Trump Pressed Oil Execs for $1B for Campaign

Former President Donald Trump asked oil industry executives in April to donate $1 billion to aid his presidential campaign, three people familiar with the conversation told *POLITICO*.

The request, first reported by *The Washington Post*, occurred during a meeting of industry executives at the former president's home in Palm Beach, Fla. Trump said the $1 billion would fuel his presidential campaign, but some executives believed the money would also be used to pay lawyers defending him in various court cases.

More: *POLITICO*, *The Washington Post*

State Briefs

CALIFORNIA

PUC Rejects PG&E Plan to Sell Generation Assets

The Public Utilities Commission on May 9 denied Pacific Gas & Electric's (PG&E's) plan to sell a multibillion-dollar stake in the utility's power generation fleet to New York-based investment firm KKR.

PG&E recently said it was working on an exclusive deal to sell a minority stake (49.9%) of its hydropower, natural gas, solar and battery energy storage assets to KKR, one of the world's largest infrastructure investors. The deal, which involved about 5.6 GW of capacity, including 3.8 GW of hydropower, was estimated to be worth $3.5 billion.

The assets also include 1.4 GW of gas-fired generation, along with 152 MW of solar and 182 MW of battery energy storage.

The PUC said "PG&E has done no substantive analysis to support the claim that the proposed transaction will be a superior alternative" to other ways to fund its operational plan.

More: *POWER Magazine*

KANSAS

Kansas Gas Service Seeks $93.1M Revenue Increase

Kansas Gas Service recently filed a $93.1 million revenue increase request with the Corporation Commission.

The request included a $58.1 million escalation in base rates and the transition of a $35 million "gas system reliability" surcharge into the base rate.

The increase would raise monthly residential bills by less than $10.

More: *Kansas Reflector*

MICHIGAN

AG Plans to Sue Fossil Fuel Companies over Climate Change

Attorney General Dana Nessel on May 9 announced her department is seeking proposals from outside lawyers and law firms to pursue litigation suing the fossil fuel industry over climate damages caused by its products.

The move adds Michigan to a list of dozens of cities and states suing companies like Exxon Mobil and BP, arguing their decadeslong efforts to conceal the perils of burning fossil fuels were criminal. Nessel said she hopes to recoup some of Michigan's costs, holding fossil fuel companies accountable for "jeopardizing Michigan's economic future and way of life."

Legal experts say billions of dollars are on the line in the suits. As huge as the financial stakes may be, a successful suit likely would not come close to covering the full cost of fossil fuel pollution, $3.1 trillion globally, as estimated in the journal *Nature*.

More: *Bridge Michigan*

Nessel Challenges Private Jet Expenses Included in DTE Rate Case

Attorney General Dana Nessel on May 7 filed testimony in DTE's most recent rate increase request, calling the $266 million request "excessive and unnecessary."

In testimony submitted by the Attorney General's Office, business consultant Sebastian Coppola said DTE's proposed gas rate hike would increase the average customer's bill by 6.5%. Coppola also pointed to DTE's estimated $74,769 jet travel costs included in the company's projected expenses submitted as part of the rate case, and the company's reporting it leased private aircrafts for executives. He recommended the Public Service Commission disallow recovery of costs for jet use.

The Department of Attorney General argued that DTE should receive a rate increase of no more than $112.2 million, resulting in about a 4% increase in customers' bills.

More: *Michigan Advance*

NEBRASKA

AG Sues Everlight Solar over Alleged Deceptive Sales Practices

Attorney General Mike Hilgers on May 8 filed a lawsuit again Everlight Solar, citing unlawful door-to-door sales tactics and deceptive practices in the sale of solar panel systems.

The lawsuit alleges that Everlight's salespeople have been misleading consumers by falsely representing the potential savings associated with solar panels. The company was also accused of using misleading savings models that omitted relevant information and accurate data.

Hilgers is seeking court orders to stop Everlight's sales tactics and impose penalties.

More: *Nebraska Television Network*

NEW JERSEY

PSE&G Seeks Double-digit Rate Increase

Public Service Electric and Gas on April 29 asked the Board of Public Utilities to approve double-digit rate increases for its residential electricity and natural gas customers.

In its filing, PSE&G said the average residential customer's bill would increase 10.48%. Meanwhile, the average heating customer's bills would increase 14.64%.

If granted, the electric and natural gas rate increase would add $462 million and $364 million, respectively, to PSE&G's annual operating revenue.

More: *70and73.com*

VIRGINIA

DEQ Issues 13 Violations to MVP

The Department of Environmental Quality on May 10 issued 13 fines to the Mountain Valley Pipeline, totaling $31,500.

The violations took place Dec. 11 through March 10 and include pollution into a creek in Franklin County and accumulation of fill material into Blackwater River. Most of the incidents were corrected within 24 hours, according to the DEQ.

More: *WVTF*

WASHINGTON

Avista to Begin Blackouts During Storms to Avoid Fires

Avista Utilities on May 7 announced it will begin rolling blackouts to combat wildfires.

The shutoffs would only be used during the summer when fire conditions become the most dangerous, and Avista would use forecasts to give alerts beginning with a "watch" as much as a week out, changing to a "warning" within a couple days and an "imminent" announcement if utility mangers plan to cut power.

More: *The Spokesman-Review*

WISCONSIN

Tx Line Through Mississippi River Refuge Approved by Appeals Court

A three-judge panel from the 7th U.S. Circuit Court of Appeals on May 9 struck down an injunction, allowing American Transmission Co., ITC Midwest and Dairyland Power Cooperative to build a transmission line and cross the Upper Mississippi River National Wildlife and Fish Refuge.

The utilities are in the final stages of constructing a 102-mile transmission line linking Iowa's Dubuque County and Wisconsin's Dane County. About a mile of the line would cross the refuge.

U.S. District Judge William Conley initially issued a preliminary injunction while he weighed the merits of the case. However, the appeals court struck down the injunction, saying Conley didn't find that the conservationists were likely to win the case — a mandatory determination to win a preliminary injunction.

More: *The Associated Press*

WEC Asks to Recoup Costs of Natural Gas Plants, LNG Facility

In recent filings by its subsidiary We Energies, WEC Energy Group has asked the Public Service Commission for permission to bill ratepayers for two new natural gas power plants, a liquified natural gas storage facility and a 33-mile pipeline to supply the proposed plants.

That filing also cites WEC's plans to convert two coal plants, the Elm Road Generating Station and Unit 4 at its Weston plant, to natural gas.

More: *Energy News Network*