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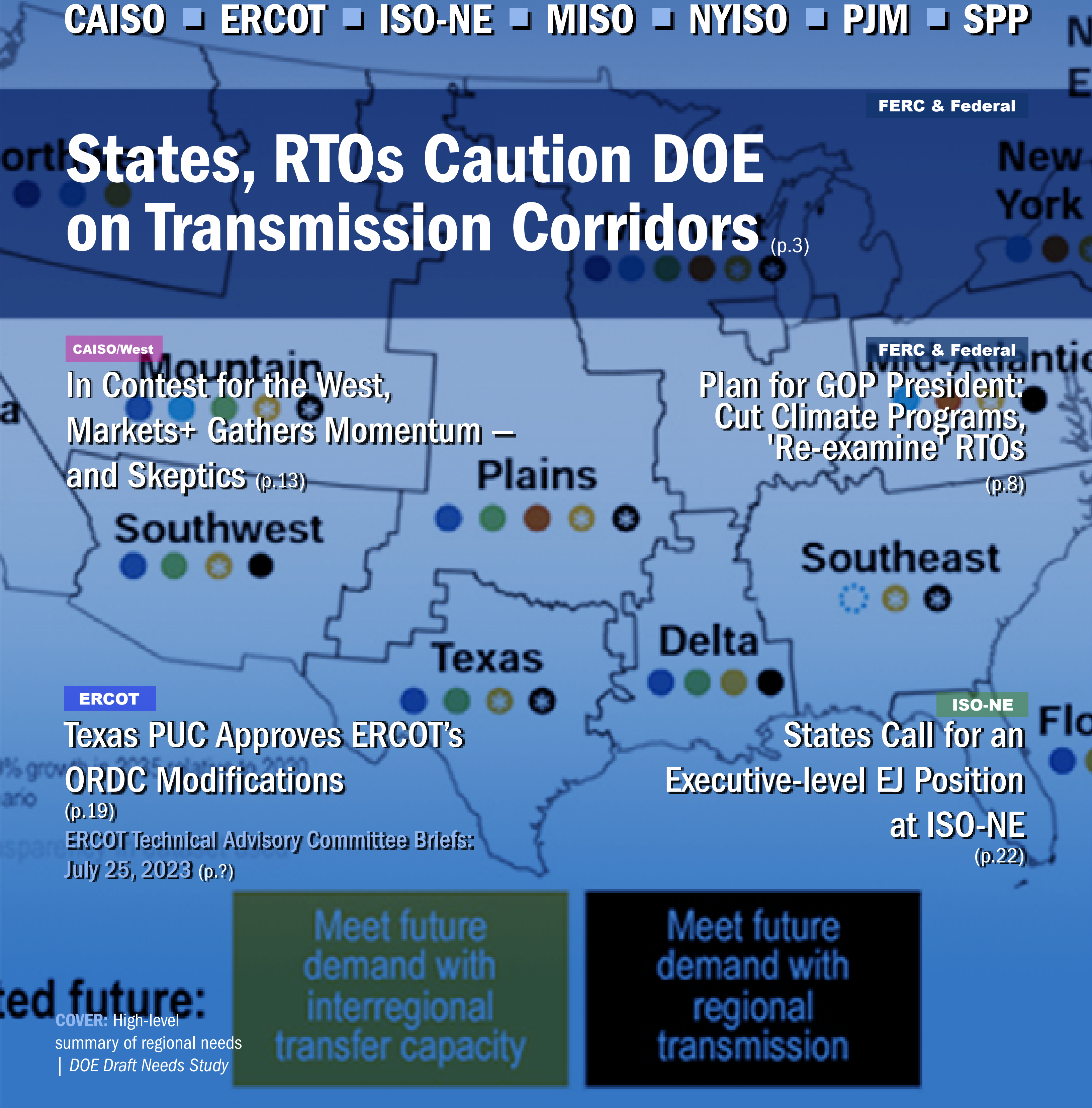
RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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



FERC & Federal

States, RTOs Caution DOE on Transmission Corridors (p.3)

CAISO/West

In Contest for the West, Markets+ Gathers Momentum — and Skeptics (p.13)

FERC & Federal

Plan for GOP President: Cut Climate Programs, 'Re-examine' RTOs (p.8)

ERCOT

Texas PUC Approves ERCOT's ORDC Modifications (p.19)

ERCOT Technical Advisory Committee Briefs: July 25, 2023 (p.?)

ISO-NE

States Call for an Executive-level EJ Position at ISO-NE (p.22)

COVER: High-level summary of regional needs | *DOE Draft Needs Study*

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Your Eyes and Ears on the Organized Electric Markets
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In this week's issue

FERC/Federal News

States, RTOs Caution DOE on Transmission Corridors

Eligibility, Ranking Process Questioned

By John Norris, Holden Mann, Amanda Durish Cook and Rich Heidorn Jr.

State officials, RTOs and public interest groups warned the Department of Energy last week not to let transmission developers dominate the development of National Interest Electric Transmission Corridors (NIETCs), saying the program should not overrun states' interests and existing regional transmission planning processes.

DOE received 112 *comments* in response to its May Notice of Intent/Request for Information on the proposed designations, which DOE says would "unlock new financing and regulatory tools" as well as federal siting and eminent domain authorities. (See *DOE Rolls out New Process for Designating Key Transmission Corridors*.)

Public officials, RTOs and trade and environmental groups were generally supportive, although many asked DOE to ensure it chooses only projects that improve resilience, enable connection of renewable generators or produce cost savings. There was wide agreement that DOE should prioritize interregional projects, and some commenters said the department should also encourage use of grid-enhancing technologies (GETs).

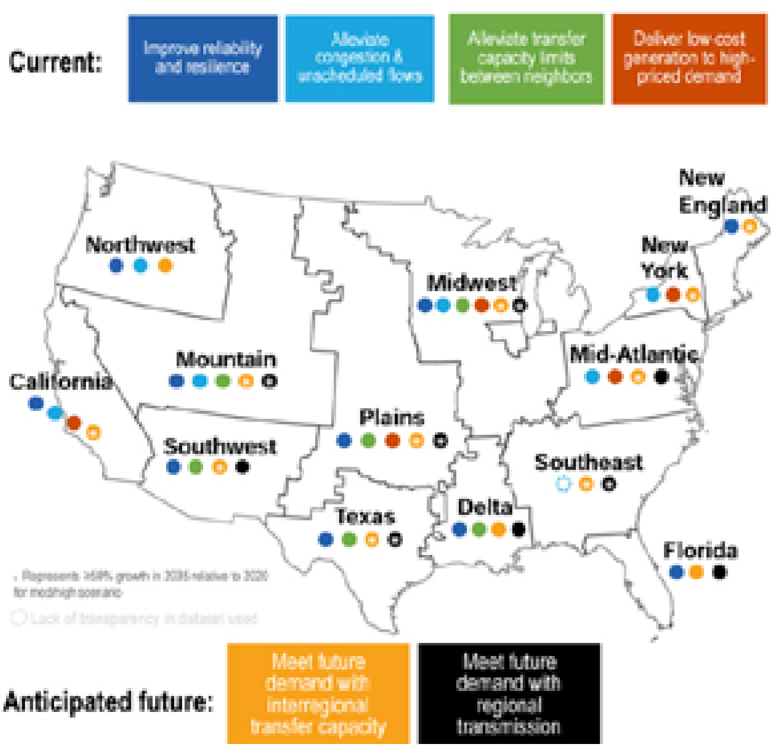
But some commenters challenged the legality of DOE's proposed "applicant-driven, route-specific" approach. Individual landowners were almost universally opposed, criticizing the potential use of eminent domain by "greedy developers."

Below, based on a review of the comments, is a summary of concerns and questions raised.

Eligibility Questions, States' Role

The Infrastructure Investment and Jobs Act (IIJA) created the Transmission Facilitation Program, giving DOE $2.5 billion for public-private partnerships to co-develop transmission projects located within NIETCs. The Inflation Reduction Act (IRA) created the $2 billion Transmission Facility Financing program, allowing DOE to offer loan support to transmission facilities designated by the Energy Secretary as being in the national interest.

DOE said it expects that most proposed routes will be "associated with specific transmission projects under active development, meaning



High-level summary of regional needs | *Department of Energy Draft Needs Study*

What are National Interest Electric Transmission Corridors and Why Do We Need Them?

Corridor Program Can Help with Things Like Siting, Commercialization

By Rich Heidorn Jr.

On May 15, the Department of Energy's Grid Deployment Office issued a Notice of Intent to create a process for designating "route-specific" National Interest Electric Transmission Corridors (NIETCs), an initiative to support transmission projects that address congestion, connect renewables or advance other policy goals. The accompanying Request for Information sought comments on DOE's proposed design for the program and suggestions for other elements that should be included.

Application Requirements

Applicants must provide sufficient information about the potential route to allow DOE's review under the National Environmental Policy Act.

DOE said it may also allow tribal authorities, states, transmission-dependent utilities, local governments, generation developers and others to submit proposals.

Applicants will be required to show that their proposed route is defined "with sufficient specificity to allow for meaningful evaluation of the potential energy and environmental impacts," including the geographic boundaries of potential corridors, and the rationale for those boundaries.

Benefits of NIETC Designation

Under the Infrastructure Investment and Jobs Act (IIJA) and Inflation Reduction

FERC/Federal News

States, RTOs Caution DOE on Transmission Corridors

that a potential applicant has progressed beyond the preliminary concept and has begun actively routing the project and engaging in community and landowner outreach, land surveys or initiation of environmental compliance work."

Although DOE said it expects most NIETC applicants to be transmission developers with a project under development, "no particular stage of development is required" for designation.

Public interest groups including the Natural Resources Defense Council, Earthjustice, the Southern Environmental Law Center and Environmental Defense Fund said DOE "must exercise independent judgment" in evaluating developers' proposed corridors, warning that DOE's proposed approach "risks conflating developers' commercial interests with the national interest."

"Although developers' NIETC proposals may reveal where there is the greatest commercial interest in transmission development, there is no guarantee that developers will propose corridors that are truly in the 'national interest,'" they wrote. "For example, they may hope that a NIETC designation will unlock financing that makes a transmission project easier to build or more profitable."

State regulators submitted comments ranging from supportive to highly skeptical, with many expressing concern that DOE's proposal would make private companies the only entities capable of applying to have NIETCs recognized. DOE said it may also allow tribal authorities, states, transmission-dependent utilities, local governments, generation developers and others to submit proposals.

The Mississippi and Louisiana public service commissions expressed strong opposition, saying the Federal Power Act grants the designation authority to the Secretary of Energy only, and contains "no language that authorizes the DOE to allow independent developers to make the NIETC designations based upon those developers' own economic self-interests."

They said the NOI could harm ratepayers. "Construction of transmission … can have enormous cost consequences on affected transmission facilities. Those consequences … must be remedied and financed by the entities causing those impacts."

The Pennsylvania Public Utilities Commission also questioned allowing "private transmission developers to be the driving force" in designating NIETCs, adding that the NOI's route-specific approach could create a presumption that transmission lines are the best solution to congestion and discourage investigation of other alternatives.

California's Public Utilities Commission and its Energy Commission supported the plan overall, but urged DOE to open the application process to states, tribes and transmission operators. They also suggested creating an "applicant-driven ministerial certification process" for projects that address the purpose and needs of a given NIETC, which would encourage developers to participate in such projects while leaving state authorities and FERC in charge of the permitting process.

'Clear and Prominent Role'

The New England States Committee on Electricity said DOE's designation process "should provide a clear and prominent role for states," allowing them to file applications for potential routes "where one or more potential transmission projects have clear state support" as well as providing input on others' proposals. "Such an approach would recognize the primacy of the states' role in siting transmission infrastructure and their authority over investments made to satisfy their own mandates and legal requirements," NESCOE said.

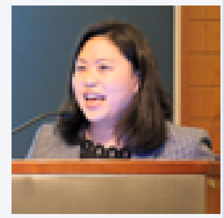
The National Association of State Energy Officials (NASEO) said that, in light of the role of state energy offices in facilitating transmission upgrades and expansion, DOE should allow them to apply for NIETC designation as well. NASEO said state energy offices "have the tools, resources and knowledge to identify potential corridors that would benefit their states, regions and the nation."

In a joint comment, the utility commissions of Michigan, New Jersey, North Carolina and Virginia pointed out that because "a NIETC designation has the potential to boost a project's chance of being constructed considerably," there is a danger that transmission developers could use the designation "strategically" to gain an advantage over projects "that may be better or more cost-effective." The commissions also feared that the designation might help "shovel-ready" projects lose ground to less prepared developers.

The Edison Electric Institute said DOE's process is "reactive" and would "unnecessarily limit DOE's evaluation of corridors to only

Act (IRA), DOE said the NIETC program "can assist in focusing commercial facilitation, signal opportunities for beneficial development to transmission planning entities, and unlock siting and permitting tools for transmission projects."

The IIJA created the Transmission Facilitation Program, giving DOE $2.5 billion for public-private partnerships to co-develop transmission projects located within NIETCs. (See *DOE Seeks Input on Tx Loan, 'Anchor Tenant' Programs*.)



Maria Robinson, director of DOE's Grid Deployment Office | *© RTO Insider LLC*

The IRA created the $2 billion Transmission Facility Financing program, allowing DOE to offer loan support to transmission facilities designated by the Energy Secretary as being in the national interest.

The IIJA also amended Section 216(b) of the Federal Power Act to give FERC the authority to overrule states when they deny a certificate for a line within a NIETC.

DOE's notice included a caveat that designation of a NIETC "does not constitute selection of or a preference for a specific transmission project for financial, siting or industry planning purposes; selection for these other purposes will continue to occur through established planning and regulatory processes."

However, some commenters expressed concern that NIETC could usurp existing transmission planning processes. (See related story, *States, RTOs Caution DOE on Transmission Corridors*.)

Reason for NIETC Program

DOE's notice cites the importance of electric transmission to national "economic, energy and national security" and says more transmission capacity is needed to survive more frequent extreme weather, provide access to renewable energy and serve rising demand from electrification of transportation and industry.

The Biden administration's goal of a 100% clean electric power sector by

FERC/Federal News

States, RTOs Caution DOE on Transmission Corridors

the areas, or indeed projects, submitted by applicants."

Rather, it said DOE should, "proactively identify the geographic areas exhibiting the most significant or persistent need for immediate transmission development."

The American Public Power Association said DOE should also allow transmission-dependent utilities to apply for NIETC designation and participate in joint ownership of projects, which it said could save ratepayers money and help win local support.

"The diversity gained by including public power in joint ownership arrangements can help with the acquisition of rights-of-way and permits, by having a broader and more diverse set of utilities advocating for projects at the state level. Engaging more rural communities and helping to bridge urban-rural division, as well as being more inclusive of rural communities, are additional public policy benefits of joint ownership arrangements that include public power," APPA said.

Respect Existing Planning Processes

CAISO, PJM and the MISO Transmission Owners were among those insisting that any procedures the DOE settles on should complement existing transmission planning efforts.

WIRES, a trade association representing transmission providers, developers, customers and regional grid managers, cautioned DOE against allowing the NIETC designation process to "inject unhelpful uncertainty into regulated transmission planning processes." It said ongoing planning initiatives like MISO's long-range transmission planning shouldn't be undermined by DOE "potentially elevating" inefficiently planned projects over those contemplated in FERC-approved planning processes.

"That situation could slow progress and erode stakeholder support for these plans and/or make it more difficult to move ahead with regionally planned portfolios that have been in the works for years," WIRES said.

WIRES, state regulators and PJM said DOE should require projects be included in a regional transmission plan before they can receive a NIETC designation.

"The NIETC process should not be used to circumvent [RTOs'] transmission planning processes. If a project is proposed as part of the RTO planning process and does not meet RTO planning or benefit criteria, then [its] proponent should not have recourse to the NIETC process to push that project into construction," regulators from Michigan, New Jersey, North Carolina and Virginia said in a joint comment. "Both are federal processes — one subject to a FERC-accepted tariff, the other this application process. Having two conflicting federally approved processes would deter, rather than promote, responsible transmission planning."

APPA agreed. "Failure of a proposed project to participate in a regional, interregional or even local planning process should weigh heavily against NIETC designation, particularly since a NIETC designation (and the prospect of FERC backstop approval) might otherwise encourage transmission developers to circumvent regional transmission planning and/or interregional coordination," APPA said.

PJM said that without an "orderly, sequential NIETC process" that recognizes the authority of RTOs and ISOs, "DOE could find itself having to referee among developers/applicants who are seeking to end-run the detailed RTO/ISO analyses and competitive planning processes … Absent such a clearly defined and sequential process, the roles of an RTO/ISO as a Planning Authority could be blurred with DOE potentially granting a NIETC designation that is at odds with the reliability, market efficiency and state public policy analyses undertaken by the RTO/ISO in choosing among competing projects."

Invenergy said DOE should solicit interregional merchant transmission projects, "which have the potential to solve critical interregional needs while largely avoiding contentious discussions on cost allocation, but which face unique barriers and hurdles."

"DOE must ensure that the process is equally accessible to transmission developers and transmission projects regardless of their business model and inclusion (or not) in a FERC-approved regional transmission planning process. Since many of the FERC-approved regional transmission planning processes exclude from consideration merchant transmission projects, as well as any other transmission projects not seeking cost allocation, inclusion in such a plan must not be a criteria in the NIETC process. … FERC-approved regional planning processes tend to be narrowly focused, considering only benefits that accrue

2035 would require increasing transmission system capacity. DOE cites a Princeton University analysis projecting that transmission systems may need to expand by 60% by 2030 and triple by 2050.

The IIJA and IRA investments "will not be realized fully unless the United States can quickly expand enabling electric transmission infrastructure," DOE said.

Identifying Corridors

A "key input" into the designation of NIETCs will be DOE's triennial study of electric transmission constraints and congestion. Although previous studies were limited to considering only historic congestion, the IIJA expanded the scope to also consider anticipated future capacity constraints that could affect consumers.

DOE issued a draft Needs Study in February and expects to issue the final study this summer. The draft found that nearly all regions in the U.S. would see improved reliability and resilience from additional transmission and that those with high electricity costs — the Plains, Midwest, Mid-Atlantic, New York and California — also would benefit from access to cheaper generation.

The study said interregional transmission would produce the largest benefits, particularly new lines across interconnection seams — between the Mountain and Plains regions and between Texas and its neighbors.

It predicted that needs will shift over time to reflect impacts from the clean energy transition, evolving regional demand and increasingly extreme weather. "Significant transmission deployment is needed as soon as 2030 in the Plains, Midwest and Texas regions. By 2040, large deployments will also be needed in the Mountain, Mid-Atlantic and Southeast regions. The same is true for interregional transmission deployment; by 2040, there is a significant need for new interregional transmission between nearly all regions," it said.

The IIJA added several outcomes, in addition to reducing congestion, that could justify transmission corridors, including impacts on a region's "economic vitality" and growth; diversifying electric supplies; helping generators connect to the grid;

FERC/Federal News

States, RTOs Caution DOE on Transmission Corridors

to that particular region and specific needs identified by the region."

ERCOT meanwhile made clear it wants no part of NIETC, saying DOE should ensure that "a proposed NIETC does not include any portion of the ERCOT region."

Metrics and Priorities

EEI criticized the NOI/RFI for lacking information on how DOE will compare and prioritize NIETC applications. "Section 216 of the Federal Power Act does not limit the number of national interest corridors that DOE may designate, but reason demands that DOE cannot designate every submitted application (or even many applications) as a NIETC," EEI said. "An explanation with respect to how DOE will evaluate the magnitude and effects of the transmission needs in proposed corridors would ensure that DOE designates the corridors of greatest need. This would further ensure prudent management of the financing tools created by the Infrastructure Investment and Jobs Act and Inflation Reduction Act."

Idaho Power said DOE should use available transmission capacity as an indicator of areas with constraints. "The amount of transmission service requests that entities receive for a given corridor and the cost of required transmission upgrades identified in transmission service request studies is also a potential metric," the company said. LMP data from the Western Energy Imbalance Market could be used to identify areas with large reoccurring price spreads in the Western Interconnection, it added.

The New York Transmission Owners said DOE's pending Transmission Needs Study should incorporate existing transmission planning processes rather than relying solely on National Renewable Energy Laboratory modeling for projecting future transmission expansion. DOE issued a *draft* Needs Study in February and expects to issue the final study later this summer.

"It is important that the study's findings are reconciled with existing transmission planning, including existing planned project solutions, in DOE's consideration of NIETC designations," the TOs said.

NRDC and the other public interest groups said DOE should favor proposals that "provide the greatest and most immediate benefits in terms of increasing interregional transfer capacity and diversification of regional resources to speed the development of wind, solar and storage resources ..." and "highly prioritize GHG reductions."

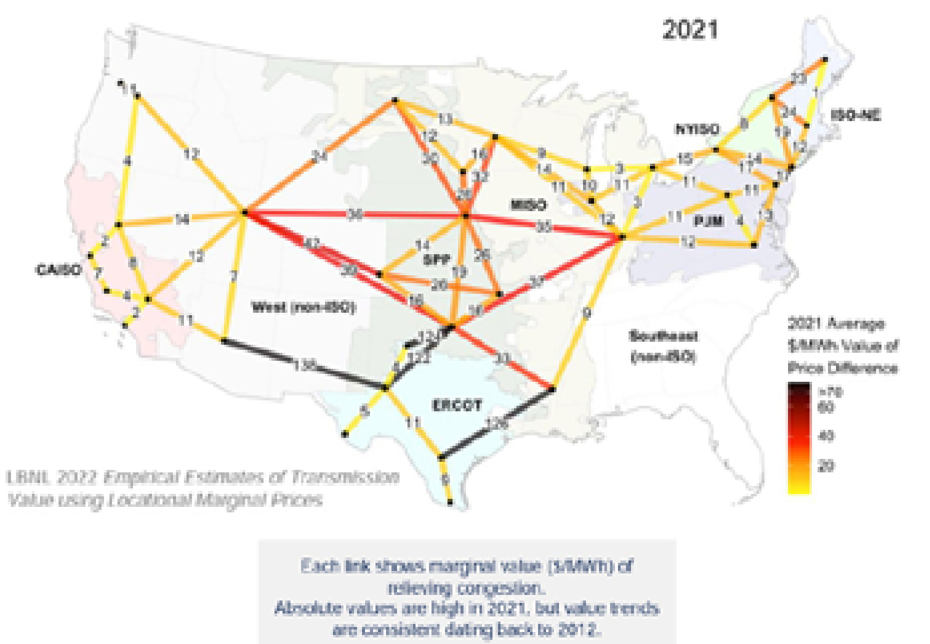
The groups said interregional transmission has shown strong benefit-to-cost ratios and cited *calculations* by MIT researchers who found that "interstate coordination and transmission expansion [including across regions and interconnections] reduces the system cost of electricity in a 100%-renewable U.S. power system by 46% compared with a state-by-state approach, from $135/MWh to $73/MWh."

"Because [interregional] projects provide great benefits but face great obstacles, they provide the best opportunity for DOE to maximize the positive impacts from NIETC designations," the groups added.

Broad or Specific Designations?

The Rail Electrification Council and NextGen Highways, which suggested NIETC designations for existing railroad or highway rights of way, praised DOE for focusing on narrower areas and specific projects than in the first NIETC effort, "an ambitious approach in 2006 that set itself up for rejection by the courts."

In 2011, the Ninth Circuit Court of Appeals vacated the first National Electric Transmis-



Largest congestion value of new transmission is across the interconnects and during extreme weather events. | *Lawrence Berkeley National Lab*

and aiding the nation's "energy independence or energy security" or "national defense and homeland security."

The IIJA also directed DOE to maximize existing rights-of-way, avoid "sensitive environmental areas and cultural heritage sites" and consult with "affected states, Indian tribes and regional grid entities."

The RFI sought comment on how DOE should evaluate the impact of a potential NIETC on generating host community benefits, "encouraging strong labor standards," improving energy equity and achieving environmental justice goals, and maximizing the use of products and materials made in the U.S.

Related Authorities of FERC and Other Federal Agencies

DOE pledged to coordinate with FERC to avoid redundancy and promote efficiency in environmental reviews.

In December, FERC issued a Notice of Proposed Rulemaking to explore how it implement its "backstop" siting authority (*RM22-7*). (See *FERC Moves to Implement New Backstop Transmission Siting Authority*.) ■

States, RTOs Caution DOE on Transmission Corridors

sion Congestion Study and its designation of the Mid-Atlantic Area national corridor and the Southwest Area corridor.

"The regional breadth of prior designations … made adequate identification and consultation with stakeholders extraordinarily difficult because of the volume and variety of landowner, environmental, economic and other issues involved," the groups said.

However, Power From the Prairie, a proposed 4,000-MW interregional HVDC line from southern Wyoming to northwestern Iowa, asked DOE to define NIETC corridors "broadly," not tying them to any established routes. It also said DOE could consider establishing a separate "promising NIETC candidate project in-waiting" category for lines in the early stages of development.

NRDC and its allies supported DOE making NIETC designations not associated with a project under development. "DOE is well situated to identify corridors that are in the national interest but where private development alone may be too challenging," they said.

EEI said DOE should reconcile an apparent conflict in the NOI/RFI between the department's assurance that it "does not intend to identify preference for specific projects within the corridors" and its assumption that proposed NIETCs will likely be "route-specific."

PJM said if DOE opens NEITC applications to generation and merchant transmission developers it should limit it to those with executed interconnection agreements.

But Con Edison said DOE should not reject projects in the early stages of development that lack details on routing and environmental impact. "Projects in the conceptual or preliminary stages of development may have significant value and stakeholder support to address emerging clean energy needs, and therefore should be accommodated and not overlooked or delayed through the DOE process due to their nascent status," the company said.

Balancing Climate and Conservation

The Arizona Game and Fish Department said while DOE is on the right track to include state, tribal and local authorities in NIETCs planning, it should also explicitly state that applicants consult with state wildlife agencies and other natural resource agencies to select routes that minimize habitat damage.

"State wildlife agencies can provide specific recommendations and information from subject matter experts on sensitive resources, species occurrence and distributions, areas of concern, wildlife connectivity, and more, as well as advise on potential conservation measures to avoid, minimize or offset potential impacts," the Arizona agency said.

Conservation organization the Land Trust Alliance urged the DOE to write in explicit protections for conserved lands; incentivize proposals that utilize existing rights of way and minimize the land use footprint of transmission corridors; and only accept route-specific applications for consideration to avoid "orphaned NIETCs that are never built out due to conservation needs being identified too late in the process."

"We must not undermine our nation's investments in and future needs for conservation by siting energy transmission infrastructure in such sensitive environmental areas as conserved lands or lands with high conservation or agricultural values. For our nation to achieve its climate goals, there must be a balance of planning for clean energy through smart siting that recognizes conservation goals."

A group of cities and communities across PJM and MISO called on DOE to develop a replicable and transparent designation process with community workshops and roundtables. They also asked DOE to require applicants to submit community benefits plans and address equitable siting issues.

"The process should seek to balance the need for timely transmission and infrastructure development with community priorities," the PJM and MISO communities said.

Legal Questions

Several commenters raised legal questions over DOE's proposed approach.

The sponsors of the Southeastern Regional Transmission Planning Process (SERTP) — including Southern Company, Duke Energy and Louisville Gas and Electric Co./Kentucky Utilities Co. — said the applicant-driven, route-specific NIETC designation is "inconsistent" with the Federal Power Act and could override state resource plans or regional transmission planning.

EEI challenged DOE's contention that the NIETC process is only guidance, saying the department must adhere to the notice-and-comment rulemaking requirements of the Administrative Procedure Act.

"DOE has taken the position that the designation of NIETCs constitute informal adjudications under the APA, not informal rulemakings. While that may be a defensible interpretation as to any given designation of a specific NIETC, that is not what DOE intends to accomplish in the planned 'guidance' that the NOI lays the groundwork for," EEI said. "Rather, the planned 'guidance' would establish a prospective, broadly applicable framework for the designation of all route-specific NIETCs. DOE must do so through a rulemaking."

Farm bureaus from multiple states — aware that their members may have lands seized through eminent domain — argued that the DOE doesn't have the authority under the FPA to prescribe applicant-driven, route-specific framework for corridors, which would "put the cart before the horse," they said. Rather, they said the DOE should "solicit input regarding specific geographic areas that should be designated as NIETCs, but not specific projects needed to alleviate congestion or constraints in those areas."

DOE cannot solicit projects that are already under development and draw a corridor around them, the farm bureaus said. Instead, they said the department must defer to states and regional planning authorities.

Some commenters questioned DOE's proposal to limit applicants' "Affected Environmental Resources and Impacts Summary" to 20 single-spaced pages, not including maps. The filing is required to detail engagements with "Communities of Interest," the status of regulatory approvals and whether the project has been included in any local or regional transmission plans. DOE also asks applicants to explain if they are using transmission technologies such as advanced conductors that allow more capacity in smaller corridors.

The Arizona Game and Fish Department said the limit should be removed.

Next Steps

DOE's NOI/RFI doesn't say how soon it will finalize its guidance on the NIETC program after reviewing comments. It has said it expects to post the final Needs Report in late summer 2023. ■

FERC/Federal News

Plan for GOP President: Cut Climate Programs, 'Re-examine' RTOs

Ex-Commissioner McNamee Offers Recommendations in Heritage Foundation 'Mandate'

By Michael Brooks

Bernard McNamee sits before the Senate Energy and Natural Resources Committee in November 2018 for his confirmation hearing to be a FERC commissioner. | © *RTO Insider LLC*

If former FERC Commissioner Bernard McNamee has his way, the next Republican president will eliminate the Department of Energy's clean energy programs and lead the repeal of the two bills enacted under President Joe Biden to combat climate change. McNamee also would direct FERC to introduce "reliability pricing" in the wholesale electric markets.

McNamee offered his recommendations as part of the conservative Heritage Foundation's recently published "*Mandate for Leadership*," a book-length guide for incoming Republican presidents to reduce the size and scope of the federal government.

McNamee authored the *chapter* on DOE and its related agencies, which calls for the president to direct FERC to "re-examine the premise of RTOs."

In an interview Aug. 1 with *RTO Insider*, McNamee did not deny climate change, but he also would not say what, if anything, a Republican successor to Biden should do. Instead he argued that the costs of the Inflation Reduction Act are out of proportion to its projected reduction in greenhouse gas emissions. He cited the Congressional Research Service's *report* on the law that said the IRA could reduce U.S. GHG emissions by 32 to 40% by 2030 compared to 2005 levels; without it, the U.S. was already on a path to reducing emissions by 24 to 35%.

"So the issue is, what's the cost-benefit to the American people [and] how do these programs impact energy security for the American people?" McNamee said.

In the forward to its most recent Mandate, its eighth, Heritage argues that "the long march of cultural Marxism through our institutions has come to pass. The federal government is a behemoth, weaponized against American citizens and conservative values, with freedom and liberty under siege as never before."

In his chapter, McNamee argues that climate change policies are threatening U.S. energy security, creating an artificial scarcity crisis that is leading to unwarranted higher costs to consumers.

"Under the rubrics of 'combating climate change' and 'ESG' (environmental, social and governance), the Biden administration, Congress and various states — as well as Wall Street investors, international corporations and progressive special-interest groups — are changing America's energy landscape," he writes. "These ideologically driven policies are also directing huge amounts of money to favored interests and making America dependent on adversaries like China for energy.

"In the name of combating climate change, policies have been used to create an artificial energy scarcity that will require trillions of dollars in new investment, supported with taxpayer subsidies, to address a 'problem' that government and special interests themselves created."

Instead, the department — which McNamee says should be renamed the Department of Energy Security and Advanced Science (DESAS) — should go back to focusing on the core missions it was created to complete, including cleaning up former Cold War nuclear material sites, working on "fundamental advanced science" and developing new nuclear weapons.

It should also prioritize studying cyber and other threats to the electric grid and pipeline networks and develop new technology to prevent disruptions, he argues.

To that end, McNamee calls for eliminating the offices of Clean Energy Demonstrations, State and Community Energy Programs, Energy Efficiency and Renewable Energy, and Grid Deployment; the Loan Program Office; and the Advanced Research Projects Agency-Energy (ARPA-E).

"ARPA-E is effectively funding projects that the private sector is unwilling to fund," he writes. "Taxpayers should not in effect be picking winners and losers — and having their dollars at risk but not gaining the economic rewards of success. ... The agency is unnecessary, risks taxpayer dollars and interferes with risk-benefit decisions that should be made by the private sector."

Ending Green Subsidies

A nominee of former President Donald Trump, McNamee served on FERC from December 2018 to September 2020. Prior to that, he worked as DOE's deputy general counsel for energy policy. In that role, he worked on the department's Grid Resiliency Pricing Rule, a

FERC/Federal News

Plan for GOP President: Cut Climate Programs, 'Re-examine' RTOs

controversial Notice of Proposed Rulemaking that would have directed FERC to order RTOs and ISOs to compensate the full operating costs of generators with 90 days of on-site fuel.

He was narrowly confirmed by the Senate, 50-49, with all Democrats in opposition, including Sen. Joe Manchin (W.Va.). (See *Senate Confirms McNamee to FERC*.) Manchin had initially supported the nomination but rescinded his approval when a video surfaced that showed McNamee criticizing renewable energy and questioning the science of climate change when he worked at the Texas Public Policy Foundation.

In his interview, McNamee noted that China is the global leader in emissions and that its government this year *approved* 106 GW of new coal-fired capacity. "So, the issue is really about making sure the American people have reliable and affordable energy."

McNamee writes that the administration should work with Congress to repeal the IRA and the Infrastructure Investment and Jobs Act, both of which he frames as intended to subsidize "renewable energy developers, their investors and special interests."

"DOE should be focused on fundamental research and science," McNamee told *RTO Insider*. The offices established by the laws, as well as ARPA-E, support technologies that have "been developed, but it's hard to get financing from the private sector to bring it to market. ... That's not appropriate for taxpayers to be taking that risk, covering that burden, covering that potential loss, especially when we're $32.6 trillion in debt. Let the private sector do it."

FERC

Many of McNamee's suggestions for FERC are familiar from when he was a commissioner and are similar to concerns made by current Republican Commissioners James Danly and Mark Christie.

"RTOs no longer seem to work for the benefit of the American people," McNamee writes. "Marginal price auctions for energy are not ensuring the reliability of the grid and are not passing the full economic benefits of subsidized renewables on to customers. FERC needs to re-examine the RTOs under its jurisdiction to make sure that they procure reliable and affordable electricity for the benefit of the American people."

States-subsidized renewable resources are jeopardizing reliability in RTO regions, so FERC should direct "RTOs to establish reliability pricing for eligible dispatchable generation resources or require intermittent resources to procure backup power for times when they are not available to operate," he writes. "A grid that has access to dispatchable resources such as coal, nuclear and natural gas for generating power is inherently more reliable and resilient."

Trump has pledged to rein in "out-of-control" independent agencies if he is returned to office and his allies have already drafted an executive order requiring agencies to submit actions to the White House for review, the *New York Times* *reported* last month. That pledge applies to FERC, *according to* *The Washington Post*. ■

FERC/Federal News

Environmentalists Call on Utility CEOs to Split with EEI on EPA Rule

Climate Groups Claim EEI Will Slam Rule in Comments; EEI Offers Mixed Assessment

By James Downing

A coalition of environmental groups wrote a letter to every Edison Electric Institute member CEO last week asking them to support EPA's proposed emissions standards for power plants. (See *EPA Proposes New Emissions Standards for Power Plants*.)

The groups say that EEI is going to come out against the rule when it files official comments by today's deadline. The letter was signed by 29 organizations but was spearheaded by Evergreen Action, a group founded by staffers of Washington Gov. Jay Inslee's (D) 2020 presidential campaign.

"During the hottest summer ever recorded, EEI is attempting to tear apart one of our best chances at ramping down the pollution that's fueling the climate crisis," Evergreen Action Executive Director Lena Moffitt said in a statement. "The power sector is the second largest contributor of the greenhouse gas emissions that are warming our planet and placing hundreds of millions of Americans under extreme heat warnings. EPA's proposed carbon standards are both common sense and one of the most powerful tools we have to ramp down that pollution."

The coalition — which includes the League of Conservation Voters, Sierra Club and Southern Environmental Law Center — claims EEI's comments will "flatly attack" EPA's proposal, especially in how it treats natural gas plants.

"We are asking you to communicate to EEI leadership that your company will not sign or endorse EEI's comments unless they commit to collaboration; and to publicly confirm that your company will engage constructively with EPA to support carbon standards for not only existing coal but also for new and existing gas plants in their final form," the groups said.

An EEI spokesperson said Wednesday that the investor-owned utility trade group was working with its "members to finalize extensive comments that are intended to help EPA develop final rules that support the ongoing clean energy transition, prioritize customer affordability and are legally durable."

"There are elements of the proposal that are favorable, and we are making recommendations to strengthen them; elements that are fixable with additional flexibilities; and elements that miss the mark," the spokesperson said. "Throughout this rulemaking process, EEI has provided EPA with extremely detailed and constructive feedback, and our filing next week will offer the same."

The environmentalists argued that utilities could leverage the billions of dollars available under the Inflation Reduction Act and other laws to control pollution, build a clean energy grid and sell to new customers as electrification efforts grow.

"On the other hand, if you align with the fossil fuel industry, rather than with clean electricity — and hide behind EEI's deeply misguided comments — the public will know where your company stands," the groups wrote. "You can expect ratepayers, regulators, climate advocates and government funders to question whether your decarbonization commitments are serious; whether you are properly mitigating ratepayer and investor risk in light of the growing crisis; and whether federal and state funds should flow towards companies doubling down on yesterday's unstable power system."

EPA's latest attempt to regulate greenhouse gas emissions from power plants has led to some criticism so far, but it also has some clear support from some industry. Advanced Energy United in June wrote a letter to EPA arguing that the grid's transition to clean energy could bolster reliability and that the proposed rule can be implemented without issue.

"Advanced energy technologies offer a variety of grid- and residential-scale solutions to weather-related and demand-side disruptions that fossil fuels do not," AEU said. "Proven methods such as demand response and energy efficiency have bolstered vulnerable grids in times of need." ■

| *Shutterstock*

TVA's Cumberland Coal-to-gas Plans Press on over Resistance

Lawsuit Seeking to Stop TVA Says it Defied NEPA

By Amanda Durish Cook

Cumberland Fossil Plant | *TVA*

The Tennessee Valley Authority's plan to swap a retiring coal plant with a new natural gas facility is making progress despite opposition from environmental groups.

The Tennessee Department of Environment and Conservation (TDEC) in late July issued an Aquatic Resource Alteration Permit to Tennessee Gas Pipeline Co. The Kinder Morgan subsidiary is proposing to build a new methane gas pipeline across three counties in Tennessee to supply TVA's proposed 1,450-MW Cumberland gas plant. (See *Nonprofits Urge TVA to Reconsider Gas-fired Options*.)

The newest permit paves the way for the Army Corps of Engineers to issue a Section 404 permit under the Clean Water Act and for FERC to move forward with its own permitting. On June 30, FERC issued a favorable, final environmental impact statement (EIS) for a natural gas pipeline to supply the plant.

Angela Mummaw of Appalachian Voices said she thought TDEC's permitting process was rushed.

"They did not take the time to seriously consider the detailed comments they received. Community members and subject experts submitted hundreds of pages of concerns, and they made a decision just five days after the comment period ended," Mummaw said in a statement. "There was no response about the new species of crayfish we discovered, or the stream that would be crossed three times in short succession, compounding the negative impacts of the open-trenching method that Tennessee Gas Pipeline Co. plans to use. Despite all the reasons we gave them not to, TDEC issued the permit anyway."

Assuming the pipeline is fully permitted, TVA will be a customer for its proposed plant.

TVA plans to retire the first of two coal burning units at the 50-year-old Cumberland plant by the end of 2026 and expects to have the planned gas plant operating before then to replace production. The Cumberland Fossil Plant failed during the December 2022 winter storm, contributing to the rolling blackouts TVA was forced to authorize.

"Natural gas is an important part of our energy system of the future. It offers flexibility to meet load demand as we add more generation, like solar power, to the mix without risking reliability and grid stability," TVA spokesperson Elizabeth Gibson said in an emailed statement to *RTO Insider*.

The Sierra Club, Appalachian Voices and the Center for Biological Diversity, represented by the Southern Environmental Law Center, filed a *lawsuit* in mid-June in U.S. District Court in Nashville hoping to stop TVA's plans to substitute one fossil fuel for another.

The lawsuit claims TVA defied the National Environmental Policy Act by committing to a new natural gas plant too early in the process, failing to seriously consider carbon-free alternatives and ignoring the climate harms and volatile fuel costs the community will bear. The groups allege TVA signed a contract with the pipeline company before completing the requisite review.

"We know that renewables with battery storage and robust energy efficiency continue to beat out fossil fuels in cost around the country, so a federal agency should be held accountable when it fails to meet the most basic requirements of the National Environmental Policy Act," Sierra Club's Amy Kelly said in a statement at the time.

The groups have said if the Cumberland replacement plant is allowed to proceed, it will emit an estimated 2.8 million tons of greenhouse gases annually. They also said TVA didn't consider the cost of mitigating air pollution from the plant in its analyses.

Appalachian Voices' Brianna Knisley said TVA struck "an early deal with an international corporation and then produced a faulty study of alternatives that was designed to favor that backroom agreement."

When TVA retires Cumberland's second coal-burning unit by the end of 2028, it may supplant the output with a separate, 900-MW gas plant in Cheatham County, Tenn., and a 400-MW battery storage system.

TVA insists it "has not yet made any decisions about replacement generation for the second unit at Cumberland Fossil Plant," according to Gibson.

However, TVA has filed a *notice of intent* to prepare an environmental impact statement for the smaller, gas-fired plant. ■

FERC/Federal News

Clean Energy Group Urges Utilities to Replace Peakers with VPPs

By James Downing

Virtual power plants can economically replace many of the country's 217 GW worth of peaking power plants, which emit pollution like nitrous oxide and are often located in population centers, the *Clean Energy Group* (CEG) said in a webinar Thursday.

VPPs are portfolios of distributed energy resources that include resources like demand response, rooftop solar, smart water heaters, plugged-in electric vehicles, batteries and other resources that are controlled by utilities or independent aggregators, said Brattle Group Principal Ryan Hledik. He authored a study released earlier this year finding VPPs were the cheapest option for resource adequacy. (See *Brattle Group Finds VPPs Cheapest Alternative for Resource Adequacy*.)

"The idea with a virtual power plant is that a utility or an aggregator will control those distributed energy resources," Hledik said. "And then ultimately, the control of those resources is done in an orchestrated, managed way to provide benefits to the power system."

Using the pre-existing resources is cheaper up front than installing peaking power plants or energy storage systems, and it helps cut emissions. Those benefits are split between the firm running the VPP program and its customer participants, Hledik said.

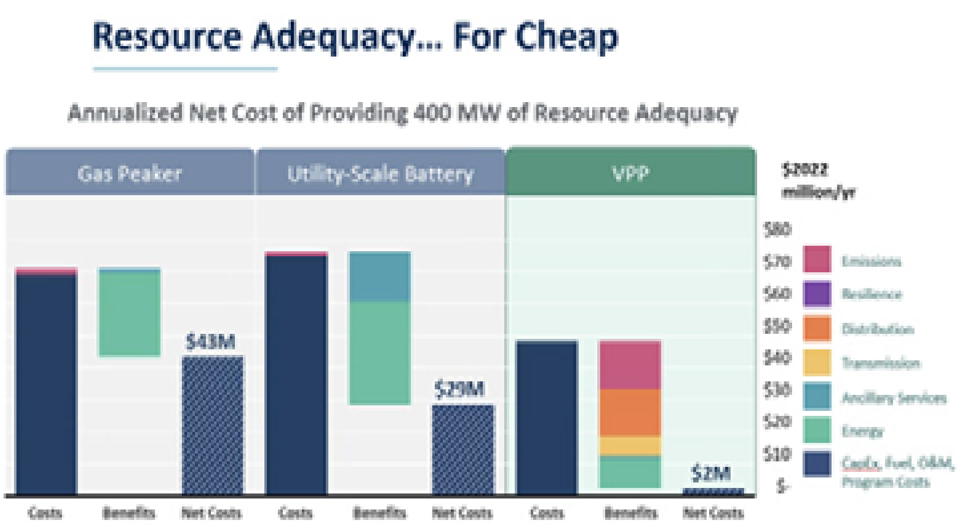
VPPs are gathering momentum because many of the costs of the DER technologies they rely on are coming down, and the expectation is that this will continue over the long run. The Inflation Reduction Act provides incentives for many of the resources, while policies like FERC Order 2222 require markets be open to aggregations of DERs.

The industry spent $120 billion on capacity that was needed to maintain resource adequacy in the last decade, and most of that went to natural gas plants, though in recent years batteries have seen an uptick in investment, said Hledik.

Brattle's analysis found that a utility with about 1.7 million customers could use a 400-MW VPP to maintain reliability. The VPP in that scenario would help lower load in both summer and winter, and be dispatched in seven months for a total of 63 hours, up to seven hours at one time, said Hledik.

While some utilities have adopted VPPs already, with the Upper Midwest's Otter Tail Power and Vermont's Green Mountain Power being listed as examples on the webinar, others are more cautious about relying on VPPs for the same level of reliability as power plants or grid-scale batteries.

"A lot of times we do encounter utilities or system operators who don't yet trust the ability of VPPs to operate and perform the way a gas peaker might or utility-scale battery might," Hledik said. "Just pushing the button and getting it to run is a little different when you think about the fact that there are customers on the other end of this."



| The Brattle Group

That kind of resistance can be overcome by doing pilot programs and seeing other utilities already successfully relying on VPPs, he added.

The shift to VPPs from gas-fired peakers can have major health benefits because some 154 GW of the power plants are in urban areas, and 32 million Americans live within three miles of one and their NO_x emissions, said CEG's Shelley Robbins.

"Because of the way they run, you pretty much can't capture that NO_x," said Robbins. "Because they don't run at a baseload level, the systems that capture pollutants don't work on these plants."

NO_x is a small particle that easily gets into the entire body through the lungs and is associated with conditions such as asthma, inflammation, cognitive decline, Parkinson's, Alzheimer's, premature birth and other medical conditions.

The peaking power plants are often located in urban areas, with a map CEG produced showing their locations overlaid on the most populous areas of the country. New York City is home to about 6 GW of peaking capacity, including some plants that are more than 55 years old, said CEG President Seth Mullendore.

To grow VPPs going forward, one policy that states could adopt is what CEG calls the "Connected Solutions Model," said its senior project director, Todd Olinsky-Paul.

"Through this mechanism, homes and businesses with batteries and other types of renewable resources can supply capacity and energy to the grid during peak demand times and also retain the use of those batteries for resilience and other needs," said Olinsky-Paul. "And in return, they get paid by the utility; whereas the utility would ordinarily pay a peaker plant, now they're paying participating customers for these services."

Customers would purchase distributed resources and sign multiyear contracts with utilities to be able to dispatch them using a VPP model, he added. It is important that such programs offer some upfront equity because often the people who want to participate the most and save on their monthly bills can least afford the upfront payments for DERs. ■

CAISO/West News

In Contest for the West, Markets+ Gathers Momentum — and Skeptics

Some Stakeholders 'Charmed' by SPP's Effort, but Others Urge Union with CAISO

By Robert Mullin

PORTLAND, Ore. — It's taken CAISO's Western Energy Imbalance Market (WEIM) nearly nine years to expand to cover about 80% of the load in the Western Interconnection since being launched with PacifiCorp as its first participant.

But after a little more than a year of outreach, SPP is contesting much of that ground as it hustles to attract participants to Markets+, a fast-rising competitor that is drawing strong interest in the West just as CAISO moves to broaden the real-time WEIM into the long-awaited Extended Day-Ahead Market (EDAM).

The near-term issue for the region's electric industry participants is which day-ahead market to choose, but their decisions likely will set the course for the eventual development of a Western RTO — or multiple RTOs.

"Once we move to a day-ahead market, that is a much larger footprint [of energy transactions]. It is much harder to transition from one day-ahead market to a separate [market] to get to an RTO/ISO," Alex Swerzbin, director of transmission and markets for PNGC Power, a Portland-based generation and transmission cooperative, said during a July 14 meeting to kick off the Bonneville Power Administration's (BPA) effort to choose a day-ahead market.

The deep interest in Markets+ was evident at a packed June meeting SPP hosted at BPA's Portland headquarters.

Attending the two-day event were about 60 people representing utilities and other organizations from across the West, including Arizona Public Service, Black Hills Energy, BPA, Portland General Electric (PGE), Puget Sound Energy, Salt River Project, Tacoma Power, The Energy Authority, Renewable Northwest and Northwest Energy Coalition (NWEC), among others.

Notably absent was PacifiCorp, which already has committed to CAISO's EDAM. The Portland-based utility controls more than 17,000 miles of transmission and 11,500 MW of generation in six states.

SPP officials running the meeting quickly got deep into the weeds, with the first day consisting of exhaustive lessons on organized market concepts (such as reliability unit commitment,

SPP presented to a packed meeting room at BPA's Portland headquarters in June. | © *RTO Insider LLC*

co-optimization, settlements and virtual transactions), peppered by back-and-forth among participants about what they would seek in the early stages of a rollout. An outside observer could be excused for assuming Markets+ already was a going concern.

"I sent some information to CAISO saying, 'Hey, you know, they're so interested in this stuff that they're considering virtuals as a starting proposition,'" Scott Miller, executive director of the Western Power Trading Forum, told *RTO Insider* in an interview shortly after the meetings.

"I think it has a lot of momentum," said one meeting participant, who is not authorized to speak on behalf of their employer, a Western utility. "They may not beat WEIM to a day-ahead market, but they have more momentum for a Western RTO."

"I think if there was one word to describe the Markets+ zeitgeist, it's 'momentum,'" Miller agreed.

"SPP is making a lot of progress," he said. "Its stakeholder process has so charmed people that it's added to that momentum."

Not all attendees were caught up in the zeitgeist.

"I can't see how we can have two markets in the West, particularly with PacifiCorp going with EDAM — and possibly PGE," one attendee said on the sidelines. That attendee also pointed out that California is by far the region's biggest player and that two competing markets would put "a big seam" in the West.

But as Miller pointed out, governance continues to be a stumbling block for CAISO's effort to expand into a Western RTO. Under California law, the ISO's governing board must be appointed by the state's governor, an unacceptable political arrangement for other Western states that bristle at prospect of yielding control of their grids to the biggest state in the nation.

California lawmakers have three times failed to pass bills authorizing an independent board, and yet another bill to address the issue has stalled in committee during the current session.

The governance problem took on a new sense of urgency last month when BPA launched its

CAISO/West News

In Contest for the West, Markets+ Gathers Momentum — and Skeptics

day-ahead market stakeholder process, committing to making a decision in the first quarter of next year.

"With EIM, we watched that market develop for several years before we even began our process of evaluating whether to join," Russ Mantifel, BPA director of market initiatives, said at the July 14 kick-off meeting. "That is very much explicitly and intentionally not what Bonneville is doing here. Our intent here is to try to be proactive, as much as possible, both in the development of these markets, and in terms of making a decision at an earlier point, in order to position ourselves to join a market earlier in the lifecycle of these markets."

In other words, with 15,000 miles of transmission and nearly 17,500 MW of generating capacity in the Northwest, BPA wants a seat at the head of the table for planning a market that likely will become the foundation for a full RTO. And for statutory reasons, CAISO's state-run governance is a clear non-starter for the federally operated BPA.

Changing Expectations

But even if California lawmakers do act on governance, Miller said, that no longer may be the pivotal issue for BAs considering a commitment to CAISO. Market participants will seek deeper cultural shift in the ISO, one that would transform its staff-driven policy process into a stakeholder-driven one like those in other multistate RTOs such as SPP, MISO and PJM.

"Now they've been exposed to a stakeholder process that the stakeholders run, and there still hasn't been a stakeholder process [in CAISO] that is developed much differently, even in the context of the EIM," Miller said.

BPA's Russ Mantifel (background, center) speaks during a June Markets+ meeting. | © *RTO Insider LLC*

"So, CAISO hasn't figured out that everybody's expectations have changed, because they haven't had a chance to yet because they've been so focused on writing their [EDAM] tariff — understandable — and trying to work with the legislature to see if they can get the governance change."

But not every Western stakeholder is so charmed by SPP's stakeholder process. Vijay Satyal, deputy director of Western energy markets at Western Resource Advocates (WRA), a Colorado-based environmental non-profit, thinks that process doesn't give fair play to perspectives from outside the electric sector.

"They're taking all the feedback of market participants, but the definition of market participants for SPP is the people who bring generation or load or both — that are utilities or customers," Satyal said in an interview. "But in the Cal ISO process, anybody can bring any issues to the table and they get addressed, and then we get responses back."

Satyal pointed out that the WEIM's Regional Issues Forum (RIF), a stakeholder body he chaired last year, will exercise new authority under EDAM "to deliberate on trending issues before they become stakeholder proposals" in CAISO.

"Can you find me a RIF design in Markets+? There isn't one conceived yet. That's an area we want to push," he said.

Satyal also offered a more generous take on CAISO's existing governance, pointing out that the WEIM's Governing Body consists of five members who are not selected by California's governor but elected by stakeholder sector committees.

"That's independence. That's parallel authority. That has truly not yet been appreciated," he said.

Furthermore, Satyal questioned the independence of the Markets+ Independent Panel (MIP), the body SPP established earlier this year as "the highest level of authority for decisions related to Markets+." He noted that the five-member MIP includes two SPP board members: Steve Wright, a former BPA administrator, and John Cupparo, previously a senior executive with Berkshire Hathaway Energy and PacifiCorp. MIP decisions are, in turn, still subject to approval by the full SPP board.

Echoing Satyal's concern was Fred Heutte, a senior policy associate with the Northwest Energy Coalition.

CAISO/West News

In Contest for the West, Markets+ Gathers Momentum — and Skeptics

"Are we the only ones who are concerned about the fact that Markets+ has a process going forward where the Markets+ board and the SPP board, neither of which have had any voice whatsoever in their selection from the West, will be actually making the decisions in this initial phase?" Heutte said at BPA's July 14 meeting. "Are there governance issues on both sides?"

The Matter of Seams

NWEC and WRA share another key concern: the impact of dividing the West into two separate markets that potentially would be cut through by a tangle of seams, depending on where various BAs choose to put themselves.

Both organizations have long been advocates for creating a single West-wide RTO that includes California to realize the full potential of sharing renewables across the region, in order to avoid curtailments and ensure a maximum reduction of greenhouse gas emissions. In that scenario, California's daytime solar surpluses are seen as a complement to a potentially vast buildout of wind energy resources in other parts of the West, as well as the existing hydro resources in the Northwest.

"We want one large market in the West," Satyal said. "There is tons of evidence that one large market will eliminate extra transaction costs, information management and different business practices where the different definitions exist in two markets."

WPTF's Miller said the seams issue could be managed by an enforceable agreement between the two markets.

"FERC would force whatever entities there are to have a joint operating agreement so that you could still sell either day-ahead or energy imbalance into each other's systems," he said.

But Heutte is skeptical about such an arrangement.

"The evidence from the East is very strong: that seams agreements are big, complicated things that never reach perfection, require a considerable amount of attention [and] include transaction costs and so forth," he told BPA officials at their July meeting.

For Satyal, the economic case for a single RTO can be found in the 2021 state-led market study that estimated that the U.S. portion of the Western Interconnection could realize $2 billion in savings a year by 2030 if it adopted one market. The study's two-market scenarios yielded considerably lower savings for the region as whole. (See *Study Shows RTO Could Save West $2B Yearly by 2030*.)

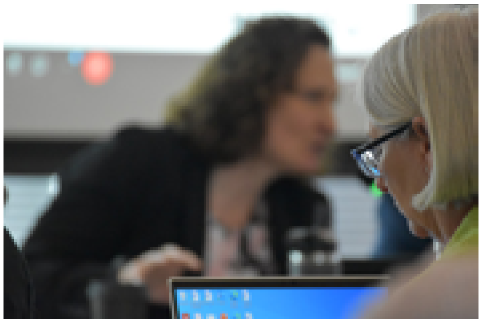
But results from a company-specific study, conducted by the Western Markets Exploratory Group (WMEG), paint a more complicated picture, industry sources have told *RTO Insider*. Those findings, released last month to individual entities, remain confidential, but the sources said they indicate California would be the biggest beneficiary of a single market, while others — but not all —actually could reap greater economic benefits from a two-market solution.

Individual utilities are expected to make those results public at their own discretion, with some required to disclose the data to their regulators before a public release, one source said. Andy Meyer, a public utility specialist with BPA, told attendees at the July 14 meeting that BPA might begin to "trickle out" its own study results starting in September, but he offered no guarantee.

"The state-led market study had a very thorough public review," Heutte said at the meeting. "Given the nature and potential impact of this decision, we hope that Bonneville will put all your cards on the table, not just the ones that lead one way or the other, whichever way, because it's really important for us to have a full understanding of what the consequences could be."

Lifeline for CAISO?

With CAISO stymied on governance, it's unclear whether the proposal last month by a group of Western utility commissioners to create an independent RTO based on the ISO's operating framework will gain traction. (See *Regulators Propose New Independent Western RTO*.)



Washington UTC Commissioner Ann Rendahl (front), a member of the Markets+ State Committee, at the June SPP meeting in Portland | © *RTO Insider LLC*

Under the plan, laid out in a July 14 *letter* to the chairs of the Western Interstate Energy Board (WIEB) and the Committee on Regional Electric Power Cooperation (CREPC), "a non-profit entity governed by representation from across the West would be formed" to contract for RTO services with CAISO, "including eventual assumption of the Extended Day-Ahead Market (EDAM) and the Energy Imbalance Market (EIM)."

The letter, signed by regulators from Arizona, California, New Mexico, Oregon and Washington, emphasized the transaction cost benefit of avoiding seams. Among the signatories was Washington Utilities and Transportation Commission member Anne Rendahl, who sits on the Markets+ State Committee and formerly chaired the WEIM's Body of State Regulators. Rendahl declined to comment for this story, saying her commission may be asked to weigh in on the market proposals in future utility proceedings.

The Western utility source who spoke to *RTO Insider* not for attribution said some industry participants outside California are skeptical that their interests would have equal footing with those of the most populous U.S. state under the arrangement.

That's a view apparently shared by former WPTF head Gary Ackerman, who in the July 21 *edition* of his widely distributed *Friday Burrito* newsletter wrote: "An independent entity with a contractual link to the CAISO will not easily satisfy multi-state governance issues because of the lopsided weight of the CAISO load relative to all the other balancing authorities outside of the CAISO. Sure, it's worth trying but expectations must be kept in check."

"The more diversity, the fewer seams you have, the more effective [a market is] going to be — I can't disagree with that," BPA's Mantifel said. "I think … the other reality is what it takes to get there, and sort of the sacrifices and compromises people are willing to make in order to achieve that, and whether that's ultimately viable."

SPP will hold meetings of its MIP and Markets+ Executive Committee Aug. 8-9 in Portland. CAISO, along with the Balancing Authority of Northern California, NV Energy, PacifiCorp and Southern California Edison, will host an EDAM forum in Las Vegas, on Aug. 29. BPA's next set of day-ahead market meetings will be held at the agency's Portland offices Sept. 11-12. ■

CAISO/West News

WEIM Tops $4B in Benefits Months After Hitting $3B

CAISO was a Major Net Exporter of Energy in the Interstate Market this Spring

By Hudson Sangree

CAISO's Western Energy Imbalance Market topped $4 billion in cumulative benefits for its participants in the second quarter of 2023, just six months after it topped the $3 billion mark at the end of 2022, the ISO said last week.

The WEIM generated nearly $799 million in benefits in the first half of this year, including $380 million in Q2, bringing its total benefits to $4.2 billion since it began in 2014. It reached $3.4 billion in cumulative benefits in the fourth quarter of 2022.

The market's benefits come primarily from transfers of lower-cost energy between Western entities, as well as operational efficiencies and increased uptake of solar and wind power.

The benefits of the WEIM, a real-time interstate trading market, grew rapidly as more participants joined in recent years. It now includes 22 entities in 11 states and British Columbia that collectively represent about 80% of load in the Western Interconnection.

Those with the most benefits in Q2 were CAISO, with $70 million in benefits; NV energy, with $46 million; and PacifiCorp, with $37.5 million.

The second-quarter results were notable for the large quantities of exports from California. CAISO had net exports of 2,758,377 MWh, nearly five times as much as the next-highest exporter, Arizona's Salt River Project, which had 564,023 MWh. NV Energy came in third with 531,979 MWh. Net exports for all other WEIM participants fell well below those figures.

Inexpensive solar energy flowing from California in the middle of the day was a likely cause of CAISO's vast net exports. The state has been adding utility-scale solar arrays at a fast pace as it tries to meet its 100% clean energy goal by 2045.

California's ample spring sunshine and moderate temperatures combined to produce an excess of solar energy in the second-quarter months from April to June.

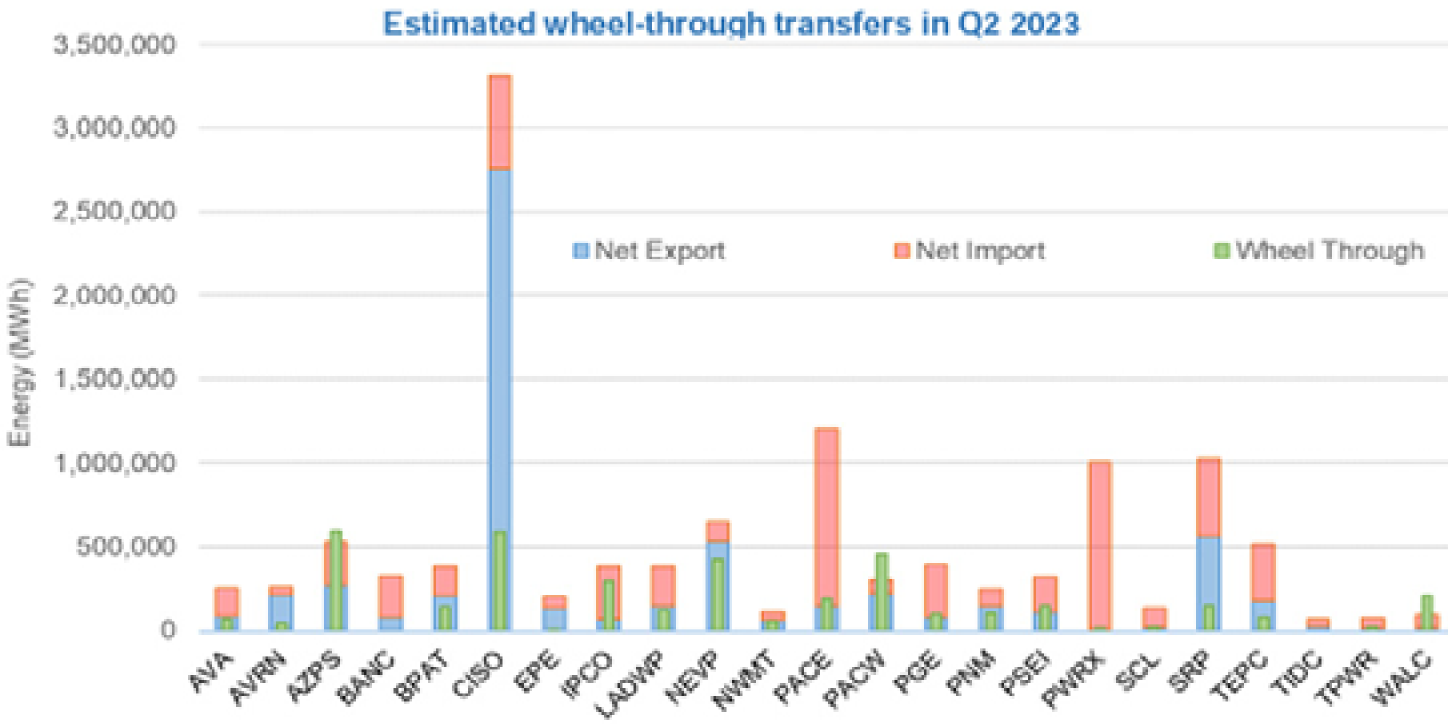
CAISO statistics show that solar output peaked May 23 at more than 15,000 MW, exceeding a 14,000-MW peak in May 2022. Then, on June 13, the ISO again broke its record for solar production with 15,718 MW.

With the latest numbers in, CAISO is hoping the proven benefits of the WEIM will convince participants to sign up for its planned extended day-ahead market (EDAM). The WEIM EDAM is likely to face stiff competition from SPP's Markets+ offering, which is planned to include real-time and day-ahead markets.

CAISO expects to file its EDAM tariff language with FERC this month. It recently *announced* a public EDAM Forum on Aug. 30 in Las Vegas, which it will co-host with PacifiCorp, NV Energy, Southern California Edison and the Balancing Authority of Northern California.

WEIM cofounder PacifiCorp has already committed to join the EDAM and several other entities are nearing a decision, CAISO said.

"The forum's panel discussions will allow a broad spectrum of utility and thought leaders to delve into the potential benefits and outstanding questions regarding EDAM participation, its evolution, and how it could transform and optimize energy delivery in the future," CAISO said in its announcement. ■



CAISO was by far the largest net exporter of energy in the WEIM during the second quarter. | *WEIM*

CAISO/West News

FERC OKs CAISO Interconnection Queue Deadline Changes

Time Extensions Intended to Deal with 'Massive' Queue Clusters 14 and 15

By Hudson Sangree

FERC last week accepted CAISO's proposed tariff revisions designed to help it deal with the overwhelming number of interconnection requests it received in 2021 and again this year (*ER23-2058*).

During the filing window for Cluster 14 in April 2021, the ISO saw a 241% increase above its previous record for interconnection requests, and 20% more projects than expected stayed in the queue for the second phase of the cluster study.

"CAISO notes that the increase required CAISO to revise its interconnection study deadlines for Cluster 14, which the Commission approved in September 2021, shortly after Cluster 14 began," FERC said Aug. 1.

The ISO received 544 interconnection requests totaling more than 350 GW in its Cluster 15 window this year, "a 45% increase above the Cluster 14 interconnection requests and a new record-high," the commission noted.

CAISO contended that studying Clusters 14 and 15 at the same time was unworkable for the ISO and its transmission owners. It asked FERC to approve changes to its tariff that extend remaining Cluster 14 deadlines by two months and to pause Cluster 15 studies until it finishes with Cluster 14, which "which effectively puts Cluster 15 on hold until September 26, 2024," FERC said.

"CAISO represents that the unprecedented volume of interconnection requests in both Clusters 14 and 15 require additional time and process to complete," it said.

Intervenors did not object, and FERC said it found the new timelines reasonable.

"CAISO explains why it is not possible to process Clusters 14 and 15 under the existing time frame in its tariff and proposes revisions that establish a transparent and reasonable approach for addressing the unprecedented challenges raised by Clusters 14 and 15," FERC said. "Accordingly, we agree with CAISO that its proposal to extend the interconnection study deadlines for Cluster 14 will help ensure that, under the circumstances, CAISO and its transmission owners have sufficient time to study these interconnection requests."

'Unbearable' Delays

Commissioner Allison Clements concurred, saying the time extensions sought by CAISO made sense to allow the ISO to deal with its "massive Cluster 14 interconnection queue cluster and to pause its even more massive Cluster 15 interconnection queue cluster."

She added that the issues CAISO faces "are emblematic of the unbearable queue delays and costs that interconnection customers and utilities are facing around the country."

"Order No. 2023, 'Improvements to Generator Interconnection Procedures and Agreements,' includes reforms that will improve interconnection processes across the country," Clements said. "However, as I noted in my concurrence, while the rule 'can be expected to improve matters, more will be necessary to solve the problem.' Therefore, I urge all transmission providers to consider the additional reforms and improvements to generator interconnection processes that I discuss in detail in my concurrence to Order No. 2023."

She appended her concurrence to last week's CAISO *decision*.

FERC approved *Order 2023* on July 27, revising its *pro forma* generator interconnection queue rules to help clear up an immense national backlog of resources waiting to interconnect to the transmission grid. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

"The final rule is one of the largest in FERC's history," acting Chair Willie Phillips said in a press conference after FERC's open meeting last month. "It represents the largest and most significant set of interconnection reforms since the *pro forma* interconnection procedures were created two decades ago."

"Our country has a severe interconnection backlog. Currently there are 2,000 GW of resources in interconnection queues, the largest backlog in history," he said.

Clements concurred in Order 2023.

"As of the end of 2022, a staggering 10,000 projects representing over 2,000 GW of potential generation and storage capacity are stuck in line to connect to the grid," she wrote. "That is nearly double the 1,250 GW of total installed capacity in the United States today."

Order 2023 will improve the situation, but more is needed, she said.

Her 23-page concurrence discussed "deeper reforms that get at some of the remaining fundamental challenges with interconnection processes." It also addresses "additional nuts and bolts changes that could enhance the effectiveness of a variety of interconnection processes, but which were not part of the proposal giving rise to this final rule," Clements said. ■

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CAISO/West News

BPA Keeps Rates Flat, Plans $2B in Grid Upgrades

By Hudson Sangree

The Bonneville Power Administration said last month that it would keep its power and transmission rates flat for the next two years, even as it pursues a $2 billion grid modernization effort.

"BPA will hold the average Tier 1 power rate and all transmission rates, including ancillary and control area service rates, flat for the next two-year period beginning Oct. 1, 2023," it said in a news release July 28. "This determination was part of the final record of decision for the BP-24 power and transmission rate case released today."

The *BP-24* rate case reflected a settlement between BPA and most of the rate case parties in a proceeding that began in November.

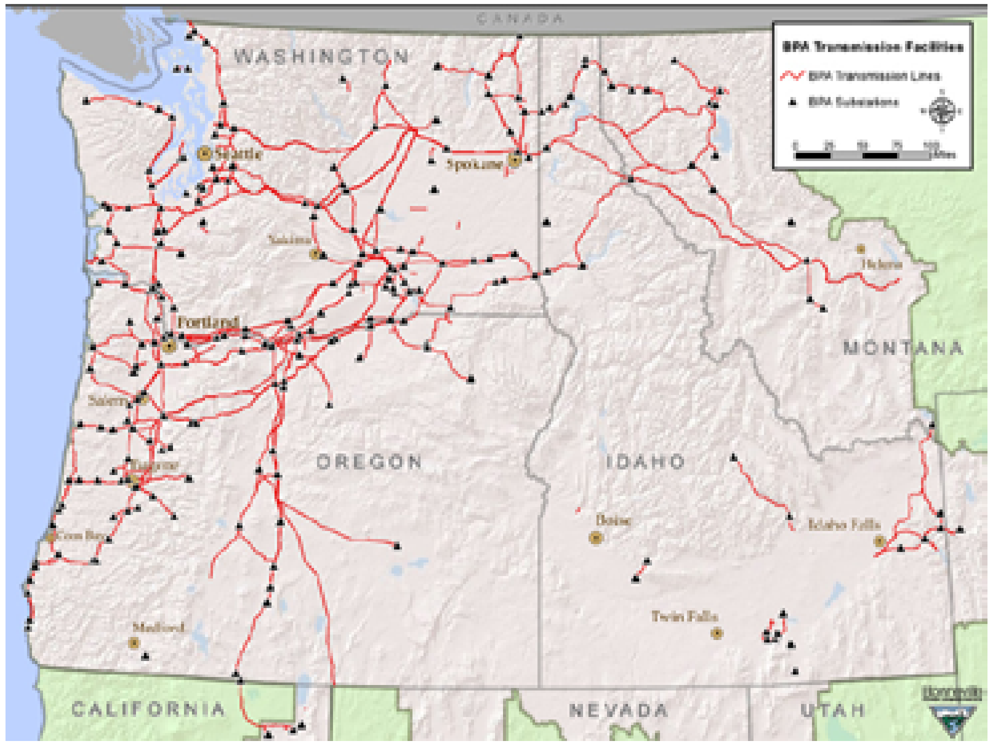
"The great collaboration with our customers and other rate case parties helped us to offer rates that are stable, predictable and low while preserving BPA's strong financial health," Administrator John Hairston said.

Tribal governments and environmental groups continued to object to the settlement agreement, saying it insufficiently funds efforts to increase salmon and steelhead runs and protect the tribes' fishing rights in the Columbia River watershed.

"BPA's BP-24 Rate Proposal takes steps to defund fish and wildlife protection, mitigation and enhancement, affording neither equitable treatment nor consistency," to bolster fish populations, the Confederated Tribes and Bands of the Yakama Nation and the Confederated Tribes of the Umatilla Indian Reservation argued in their initial brief.

"The BPA administrator should reject the BP-24 Rate Proposal and significantly increase fish and wildlife funding in the BP-24 rate calculation to ensure sufficient progress towards measurable increases in adult salmon and steelhead returns in the coming years," the brief said.

But Hairston said in the news release that "BPA is well positioned to meet our customers' needs across our service territory, including reinforcement of our existing grid and new infrastructure to meet anticipated load growth and the further proliferation of renewable resources coming into the region."



| BPA

On July 13, BPA said it was "moving forward with more than $2 billion in multiple transmission substation and line projects necessary to reinforce the grid. These projects are intended to increase capacity and accommodate regional growth, as well as an abundance of new, clean energy resources."

Six of the projects will "reinforce existing major BPA transmission lines that run from east to west, allowing the flow of energy from the east side of the region to load centers such as the Puget Sound area and Portland," it said. Projects in Central Oregon, "where utilities are experiencing significant growth and are attracting large commercial customers," include a new transmission line and substations, with an estimated cost of $839 million.

BPA said *grid modernization* helps it participate in CAISO's Western Energy Imbalance Market, which it joined last year. It is also participating in the development of CAISO's proposed extended day-ahead market for the real-time WEIM and in SPP's development of its planned Markets+ offering in the West, which includes a day-ahead market.

To pay for the infrastructure projects, BPA received a $10 billion boost in its borrowing authority with the U.S. Treasury under the Infrastructure Investment and Jobs Act of 2021, which raised BPA's borrowing line from $7.7 billion to $17.7 billion.

BPA is self-funded; it must repay the Treasury with revenues from its power and transmission rate revenues.

"BPA sets its rates to ensure the probability of repaying its annual U.S. Treasury debt is at least 95%, which is the last payment it makes after all other obligations are paid," it said. "BPA has made its Treasury payment on time and in full for the past 39 years. With the increased funds [$258 million] set aside for risk and its other sources of liquidity, the probability of making the Treasury payment over the BP-24 rate case period is more than 99%."

The rate case takes effect Oct. 1 and runs through Sept. 30, 2025.

"BPA will file the case with the Federal Energy Regulatory Commission, requesting interim approval for the rates while awaiting final FERC approval," it said. ■

ERCOT News

Texas PUC Approves ERCOT's ORDC Modifications

Price-floor Adders Designed to Incent New Generation, Reduce RUCs

By Tom Kleckner

Texas regulators last week endorsed ERCOT's proposed modifications to the operating reserve demand curve (ORDC) designed to retain and attract dispatchable generation.

"I believe that near-term action is important to retain our long-duration, dispatchable thermal generation assets that I believe are extremely necessary to maintain reliability during extreme weather conditions," Commissioner Lori Cobos said during the Public Utility Commission's open meeting Thursday.

Under ERCOT's multistep proposal, price adders of $20/MWh and $10/MWh will be set when operating reserves hit floors of 6,500 MW and 7,000 MW, respectively. Staff's analysis indicates the floors would have increased revenues to generators by about $500 million during the 2020 and 2022 pricing years. Thermal generators would have received 80% of those revenues.

ERCOT says the ORDC increasing during substantial operating reserve surplus periods will improve pricing signals, help retain existing assets, add new dispatchable generation and reduce the frequency of reliability unit commitments (RUCs).

Cobos filed a *memo* before the meeting explaining the need for a "market-based tool" that incents generators' self-commitment in the real-time market to help reduce RUCs. To ensure the ORDC modification's goals are met, she also laid out three metrics ERCOT will be required to track and report back to the commission (*53298*):

- The amount of new revenue specifically resulting from the adders;
- The specific type of generation resources that received the new revenue; and
- Performance data showing whether the adders have reduced ERCOT's use of RUC.

"I think these metrics will help us keep track of whether or not this action is accomplishing what we set out to do," Cobos said.

Texas PUC Commissioner Lori Cobos lays out her metrics to evaluate the results of the ORDC changes. | *Public Utility Commission of Texas*

She also recommended the PUC re-evaluate the need for the price-floor adders after ERCOT deploys dispatchable reliability reserve service in December 2024 to check that RUCs are reduced by the amount of the new ancillary service ERCOT procures.

Commissioner Jimmy Glotfelty said he struggled with ERCOT's proposal but joined the PUC's unanimous decision.

"It's not clear to me that we are creating a bridge solution to eliminate RUC or that we're creating a bridge solution to bridge us to a reliability capacity issue to solve our resource adequacy issue," he said. "If we want to eliminate RUC, I think we should be looking at all of the solutions that could eliminate RUC, not just one. I know RUC is problematic for generators, but what I don't want is another out-of-market solution to solve an out-of-market solution that we created which solved a conservative operations out-of-market solution that we created. We're just piling on by trying to fix the market with other modifications."

The PUC in January directed ERCOT to propose a bridge to the commission's proposed market redesign, a performance credit mechanism (PCM). However, the design's chief proponent, former commission Chair Peter Lake, stepped down from his post in June after Texas lawmakers suggested other market structures during their recent legislative session. (See *Texas PUC's Lake Steps Down as Chair*.)

The grid operator's stakeholders and Board of Directors approved the staff's proposal in April. (See *ERCOT Stakeholders Endorse Staff's Bridge to PCM*.)

ERCOT's ORDC values the wholesale market's operating reserves on their scarcity, reflecting that value in energy prices.

The curve has been modified several times since it became part of the market in 2014. The value of lost load, which is set equal to the system-wide offer cap, was changed from $9,000/MWh down to the $2,000/MWh low-system-wide offer cap after the 2021 winter storm, then back up to $5,000/MWh in January 2022. The minimum contingency level also was increased last year from 2,000 MW to 3,000 MW.

Entergy Texas Gets Rate Increase

In other actions, the PUC approved an unopposed settlement that increases Entergy Texas' base rate revenues by $54 million, resulting in a nonfuel revenue requirement of $1.23 billion. PUC staff, the Office of Public Utility Counsel and Texas Industrial Energy Consumers were among the signatories to the agreement (*53719*).

At the same time, the commission severed into a new proceeding two contested issues related to Entergy's proposed electric vehicle charging riders. The PUC will determine whether it is appropriate for a vertically integrated utility to own EV charging facilities or other transportation electrification and charging infrastructure.

The commission also rejected rehearing requests by Texas Energy Association for Marketers, Alliance for Retail Markets and Texas Competitive Power Advocates over the approval of a partial settlement that reduced CenterPoint Energy's distribution cost recovery factor by $7.8 million (*53442*). ■

ERCOT: Normal Ops As Demand Hits Records

More Extreme Heat Expected this Week, into next

By Tom Kleckner

The ERCOT grid continues to operate under normal conditions, the grid operator said Monday, even as this summer's peak demand is 4.3% higher than last summer's.

The Texas grid operator recorded a new high for hourly peak demand average of 83.59 GW on Aug. 1. On Saturday, it recorded an unofficial high for weekend peak demand when load averaged 83.46 GW during the interval ending at 5 p.m.

In comparison, ERCOT set a then-record for peak demand of 80.15 GW last summer. Average hourly demand has exceeded that mark 90 times this summer, through Sunday.

ERCOT on Monday extended through Friday a weather watch, its fourth of the year, that it had issued for Sunday and Monday because of forecast higher temperatures and demand and the potential for lower reserves. It *projected* demand to break 86 GW on Monday and peak demands above 84 GW and higher through Friday.

Weather watches are issued when possible significant weather is expected along with high demand. They do not require public conservation. However, several utilities have been asking customers to reduce their usage.

"Grid conditions are expected to be normal," ERCOT *tweeted*.

"Copy and paste. More heat and more sun," *Space City Weather* said Friday in warning that Texas' oppressive heat won't break until next week at the earliest. "Any changes that take place in the weather pattern would not materialize before next weekend. So, buckle in."

The sprawling Houston region finds itself underneath the brutal heat dome that is causing *abnormal problems for vehicles*. The National Weather Service issued excessive heat warnings for several counties in the region Friday as heat indexes soared as high as 113 degrees Fahrenheit.

In an email response to an interview request with ERCOT staff, the grid operator said it was not scheduling interviews and pointed to its new *Texas Advisory and Notification System* as a way to stay updated. (See "New Grid Notifications Added," *ERCOT Monitor Recommends New Market Design in Report*.)

However, *during a recent presentation* last month in San Antonio to the Texas Public Power Association, ERCOT CEO Pablo Vegas said he is concerned about the grid's long-term reliability, given the continued influx of wind, solar and storage resources. At the same time, he credited renewable energy with helping staff meet record demand.

"Peak demand kept growing," Vegas said. "We're in a place now where we are dependent upon renewables to meet demand."

Solar resources produced a record 13.46 GW of energy Wednesday and, with wind, accounted for more than 31 GW of energy last month, according to *GridStatus*. ERCOT has more than 55 GW of solar and wind capacity and an additional 3.5 GW of battery storage.

Thermal outages have averaged around 6 GW in recent weeks. Still, prices settled as high as $2,886 at 5 p.m. Friday and didn't drop from quadruple digits until after 8 p.m. Prices briefly reached $26.25 Sunday evening. ■

ERCOT Technical Advisory Committee Briefs: July 25, 2023

Members Endorse $329M CPS Energy Reliability Project

ERCOT will ask its Board of Directors to approve a $329 million reliability project in the San Antonio area following an endorsement from stakeholders last month.

The Technical Advisory Committee approved the project as part of its combination ballot during its July 25 meeting, agreeing with staff's recommendation that the project is critical to the ERCOT system's reliability.

The project addresses thermal overloads in the San Antonio area and has been designated as a Tier 1 project because of its estimated capital costs of $100 million or more, thus requiring board approval. The board next meets Aug. 30-31.

CPS Energy, San Antonio's municipal utility, submitted the project for the Regional Planning Group's review in December. The staff-led RPG is the grid operator's primary forum for discussion, input and comment on planning issues.

ERCOT staff studied five options for the project, shortlisting three. They determined the chosen option improves long-term load-serving capability and operational flexibility and provides an additional transfer path from South Texas into the San Antonio area.

The preferred option does lead to congestion on a line, but upgrading the line does not yield economic benefits, staff said, and it will not be included in the project.

The project involves building 50 miles of new double-circuit 345-kV lines and rebuilding an additional 25 miles of 345- and 138-kV lines. CPS expects to complete the project by June 2027.

The CPS Energy reliability project | *ERCOT*

RTC Stakeholder Group to Form

Now that work has resumed on real-time co-optimization (RTC), ERCOT wants to reconstitute the stakeholder group that produced seven nodal protocol revision requests (NPRRs) and two other changes to guide the grid operator's implementation of that market

ERCOT Technical Advisory Committee Briefs: July 25, 2023

tool that procures energy and ancillary services every five minutes. (See *ERCOT Technical Advisory Committee Briefs: Nov. 18, 2020*.)

ERCOT's Matt Mereness, who guided the RTC Task Force, will chair the proposed working group. A vice chair has not yet been identified. Work is to begin in September, with a targeted delivery of 2026.

The group will use the NPPRs to develop business requirements for RTC and single-model batteries. It also will review a state-of-charge concept for batteries. Staff are drafting a charter for this month's TAC meeting.

The RTC Task Force was disbanded at the end of 2020 following completion of its work. The disastrous and deadly 2021 winter storm and the ensuring drain on staff postponed further work on RTC and batteries until recently.

Combo Ballot

TAC members approved a change to the Verifiable Cost Manual (*VCMRR034*) despite concerns from generators that it will create confusion over what can be included in the fuel adders. The revision provides that actual fuel purchases used to determine the reliability unit commitment guarantee will not be included when calculating fuel adders.

The measure passed 26-1, with Luminant casting an opposing vote and Calpine, ENGIE and Jupiter Power all abstaining.

The committee also considered a separate motion on *NPRR1165*, which would strengthen ERCOT's market entry eligibility and continued participation requirements for qualified scheduling entities, congestion revenue right account holders and other counterparties. The measure passed 29-1, with only CPS Energy in opposition.

NPRR1165 would remove minimum capitalization requirements, require counterparties to post independent amounts, remove references to guarantors, clarify financial statement requirements and reference International Financial Reporting Standards rather than retired International Accounting Standards.

TAC's combination ballot included three additional NPRRs, two revisions to the nodal operating guide (NOGRRs), another binding document request (OBDRR) and a change to the planning guide (PGRR). If approved by the board, these changes would:

- *NPRR1176* and *NOGRR252*: revise the Energy Emergency Alert (EEA) procedures to require a declaration of EEA Level 3 when physical responsive capability (PRC) cannot be maintained above 1,500 MW and require ERCOT to shed firm load to recover 1,500 MW of reserves within 30 minutes. The NPRR also would modify the trigger levels for EEA Level 1 and EEA Level 2, change the trigger for ERCOT's consideration of alternative transmission ratings or configurations from advisory to watch when PRC drops below 3,000 MW, and restore a frequency trigger for the EEA Level 3 declaration if the steady-state frequency drops below 59.8 Hz for any period of time.
- *NPRR1182*: incorporate controllable load resources and energy storage resources (ESRs) into the constraint competitiveness test's long-term and security-constrained economic dispatch (SCED) versions. Controllable load resources will not be mitigated but will be used to identify whether a market participant has market power in resolving a transmission constraint; other resources' registration data will be used in the long-term CCT process, and real-time telemetry will be used in the SCED CCT process.
- *NPRR1183*: revise rules for and make publicly available on ERCOT's website general information documents that don't include ERCOT critical energy infrastructure information (ECEII), remove a reference to the Freedom of Information Act from the ECEII's definition and remove antiquated or duplicative language related to reliability must run.
- *NOGRR247*: increase the under-frequency load shed (UFLS) program's load-shed stages from three to five and change the transmission operator load-relief amounts to uniformly increment by 5% for each stage, add a UFLS minimum time delay of six cycles (0.1 seconds) and add 59.1 Hz to the list of UFLS stages, and revise the gray-box language from *NOGRR226* to provide that the TO load value used to determine load at each frequency threshold will be the TO's load at the time frequency reaches 59.5 Hz.
- *OBDRR047*: clarify treatment of unused funds from previous emergency response service standard contract terms.
- *PGRR108*: update language to reflect the current practice of posting regional transmission plan and geomagnetic disturbance (GMD) assessment plans and update data sets. ■

— Tom Kleckner

ISO-NE News

State Officials Call for an Executive-level EJ Position at ISO-NE

By Jon Lamson

Environmental justice activists in Peabody, Mass., protesting the construction of a new oil and gas peaker plant | © RTO Insider LLC

High-level energy officials from Connecticut, Maine, Massachusetts, Rhode Island and Vermont asked ISO-NE to establish an executive-level environmental justice position, in a *letter* last week.

"At the highest level, this position would provide an EJ and equity lens to ISO-NE's management and staff, inform the development of ISO-NE initiatives, rules and operations and engage EJ communities and stakeholders," the officials wrote Aug. 1.

The officials said responsibilities of the position could include advising the ISO-NE Board of Directors and senior management on market rules, transmission planning, operations and new initiatives, along with performing outreach to environmental justice communities and facilitating internal training.

The environmental justice needs at ISO-NE may require multiple positions, the commissioners and energy officials said.

"As community engagement and responsibilities grow, this executive position could build out and manage additional team members providing EJ expertise to ISO-NE and enhancing community, government and industry engagement," the letter says.

All the states represented in the letter have environmental justice provisions written into law intended to protect communities that disproportionately face the negative effects of energy infrastructure. These communities frequently are lower-income, non-white and non-English speaking. New Hampshire, which did not sign the letter, is the only New England state that does not have an environmental justice statute.

The state officials' request came in response to ISO-NE's presentation to the New England states in June on the preliminary operating and capital budgets. ISO-NE proposed a 21.5% budget increase for 2024 in its presentation to the NEPOOL Participants Committee. The RTO framed the budget increase in part as "ramping up its capabilities" to help facilitate the transition to clean energy resources. (See *ISO-NE Considers Major Capacity Market Changes*.)

"There is a gap in ISO-NE's budget proposal and its current management team without a position reflecting EJ experience," the letter says. "A successful clean energy transition cannot happen without community engagement and a meaningful role for EJ communities in helping to shape decisions that impact wholesale power and transmission rates and affect how the benefits and burdens of our electric system are apportioned."

The letter acknowledged that such a position may be unprecedented at RTOs across the country.

"We understand that if ISO-NE creates a dedicated EJ position, it may be the only independent system operator or regional transmission organization in the country that has established such a role," the state officials wrote. "We encourage ISO-NE to be first in this critical area."

In response to the letter, ISO-NE said it is open to input from the states on environmental justice issues.

"We've received the letter and look forward to continuing our conversations with the New England states and stakeholders on issues related to environmental justice and the clean energy transition, both in the context of our annual budget and beyond," ISO-NE said in a statement to *RTO Insider*.

Mireille Bejjani, co-executive director of the environmental justice organization Slingshot, applauded the state's proposal, saying it's an important step.

"ISO New England doesn't have a track record on environmental justice; it hasn't been something they have taken into account," Bejjani said, noting that ISO-NE's main considerations have been limited to cost and reliability. "The potential creation of the position is really exciting because it could change the conversations that are happening so that when reports are being put together and decisions are being made, we're taking into account the human side of the grid."

Bejjani said it is important to give the position real authority and decision-making power, and not to use it as justification for a business-as-usual approach. She also echoed the need to expand the role beyond a single position.

"It's too much work for one person to manage all of the environmental justice concerns for an entire grid operator," Bejjani said.

Susan Muller, senior energy analyst for the Union of Concerned Scientists, said it's especially important to give environmental justice communities representation in the NEPOOL process, which was not specifically mentioned in the letter.

"The NEPOOL stakeholder process is where most of the decisions are made," Muller said. "The person in this position should be thinking about how to make the NEPOOL process accessible to the impacted communities … right

ISO-NE News

State Officials Call for an Executive-level EJ Position at ISO-NE

now, it would be almost impossible for most communities to participate in the NEPOOL committee process."

Muller added a distinction must be made between outreach to energy infrastructure host communities and energy consumers. ISO-NE's Consumer Liaison Group meets to engage with energy consumers four times a year. She added that ISO-NE is not alone among the country's ISOs and RTOs in its historical lack of consideration of environmental justice.

In June, a coalition of climate and environmental justice organizations (including the Union of Concerned Scientists) submitted to MISO a set of "equitable grid principles," calling on the organization to prioritize human rights, accessibility, and climate resilience in its decision-making processes. (See *MISO Stakeholder Activists Propose Equity Principles*.)

MISO responded by acknowledging the importance of the principles but argued that their members and state regulators were better situated to address the issues. ■

NEPOOL Approves ISO-NE DASI Proposal

RTO Plans to Integrate DASI into Wholesale Markets by March 2025

By Jon Lamson

NEPOOL approved a set of tariff changes related to ISO-NE's Day-Ahead Ancillary Services Initiative (DASI) proposal at the August Participants Committee meeting, held virtually Thursday. The vote gave final NEPOOL approval of the DASI proposal, as the changes previously had been approved by the Market, Reliability and Transmission Committees.

"ISO New England has been working with stakeholders on … DASI for almost a year and we're pleased NEPOOL approved DASI," ISO-NE told *RTO Insider* in a statement following the vote. "We plan to prepare and file our DASI proposal with FERC in October of this year. Our plan is to have DASI integrated into New England's wholesale markets by March 1, 2025."

The DASI proposal is intended to procure and price ancillary services to ensure the reliability of the day-ahead market. (See *ISO-NE Plans 2025 Launch for Day-Ahead Ancillary Services Initiative*.)

In a July *memo*, ISO-NE wrote that the current Day-Ahead Energy Market, which clears just one energy product based on supply offers and demand bids, leaves gaps when unforeseen generation and infrastructure issues arise and when the market clears less supply than forecasted load.

"The DASI proposal creates a Day-Ahead Ancillary Services Market that, together with today's Day-Ahead Energy Market, creates a single, jointly optimized Day-Ahead Market," ISO-NE wrote. "These new day-ahead ancillary services will encourage reliable resource performance and prepare the system on a day-ahead timeframe with the flexibility needed to manage operational uncertainties."

While approving the proposal, members of the Markets Committee have asked ISO-NE to reassess the strike price adder when more data is available following implementation. NEPOOL members also have raised concerns related to the DASI's effects on peaker plants, as well as concerns about the elimination of the Forward Reserve Market (FRM). ISO-NE plans on removing the FRM when DASI takes effect in March 2025.

"The FRM is no longer necessary in its suite of markets, given the development of the new Day-Ahead Ancillary Services and in light of the significant transmission and market improvements that have been made over the last decade to relieve locational constraints and reward resource flexibility and performance," ISO-NE said.

Also at the August PC meeting, the committee voted to approve ISO-NE's proposed Order 881 compliance changes drafted in response to a June 15 FERC order (*ER22-2357*), as well as tariff changes related to FERC's request for further compliance with Order 2222 (ER22-983). (See *FERC Gives ISO-NE Homework on Order 2222, Order 881 Timelines Need Explaining, FERC Says*.) ■

FERC Approves Updates to ISO-NE Inventoried Energy Program

Program Goal: Pay Generators to Store Fuel During Winter

By Jon Lamson

| Shutterstock

FERC on Friday approved a series of updates to ISO-NE's Inventoried Energy Program (IEP), replacing the IEP's fixed forward and spot rates with indexed rates intended to reflect natural gas price changes (*ER23-1588*).

The commission sided with ISO-NE over the protests of the official consumer advocates for Massachusetts, Connecticut, New Hampshire and Maine, as well as a group of environmental nonprofits, which argued that the changes would increase electricity costs for consumers.

"The revisions maintain the overall structure of the commission-approved Inventoried Energy Program, while updating the tariff to help ensure that the Inventoried Energy Program can fulfill its purpose of incenting resources to maintain inventoried energy during periods when reliability is most threatened," the commission wrote, making the revisions effective Aug. 4, as requested.

The goal of the IEP is to pay generators — mostly oil and gas power plants — to keep up to three days of stored fuel on-site during the winter to ensure reliability for the region.

FERC agreed with ISO-NE that the updated rates more accurately reflect market conditions, noting that the changes will do away with fixed payment rates based on 2019 fuel price data. (See *Gas Volatility Leads ISO-NE to Seek Update to Inventoried Energy Program.*)

"Current fuel prices exceed these fixed payment rates, which could reduce incentives to participate in the Inventoried Energy Program," FERC said.

In joint comments to FERC opposing ISO-NE's IEP proposal, the Sierra Club, the Conservation Law Foundation and the Union of Concerned Scientists argued that the changes to the program would lead to substantially increased costs for ratepayers. The organizations noted the IEP updates could increase the total cost of the program from $300 million to $800 million over two years according to the upper-bounds analysis of ISO-NE, "all for suggested, but deeply uncertain, benefits to consumers."

The state consumer advocates pressed the commission to consider the high costs of the Mystic cost-of-service agreement before authorizing the likely increase of costs related to the IEP. (See *Public Power Groups Seek Information on Mystic Agreement.*)

"The commission cannot and should not ignore the magnitude of impact that the Mystic COSA has had on consumers in determining the justness and reasonableness of the IEP Redesign," the consumer advocates wrote. "The IEP Redesign includes very little support despite imposing potentially massive costs on ratepayers, which is especially egregious in the context of the COSA's similarly massive costs."

The commission said it had already settled many of the issues the protestors raised.

"The proposed revisions at issue here reflect only narrow modifications and provide no basis to revisit past findings related to the Inventoried Energy Program's core structure, which will remain unchanged," it said.

FERC also disagreed with the contentions that ISO-NE did not adequately demonstrate the need for the IEP, that the IEP could result in windfall payments for oil generators and that the costs to consumers would likely outweigh the benefits.

'Funny Fuel Supply'

ISO-NE applauded the commission's ruling.

"With the commission's acceptance, we're moving forward on promptly implementing these updates into the upcoming winter," the grid operator said in a statement to *RTO Insider*, adding that the updates "will align the program with current market conditions."

Meanwhile, the Sierra Club, the Conservation Law Foundation and the Union of Concerned Scientists expressed displeasure with the ruling.

"CLF is disappointed by the commission's decision, which approves changes to an ISO-NE program that extends our region's overreliance on expensive, imported and polluting fossil fuels at a time when we need to be deploying clean energy resources," Phelps Turner, senior attorney for the Conservation Law Foundation, told *RTO Insider*.

"The fossil-fuel-fired generators that it seeks to incentivize appear to already have a legal obligation to be fuel-ready and, in any event, they have substantial economic incentives to be ready and to perform, without the need for consumer subsidy," Turner added.

Casey Roberts, senior attorney for the Sierra Club, said the FERC-approved changes could ultimately amount to a handout to the gas and oil generators covered in the IEP.

"A major vulnerability of gas and oil generators … is that they have this funny fuel supply situation that it can be challenging to get their fuel during the times it matters most," Roberts said. "FERC is basically compensating them for that, instead of having those generators bear that risk and pay those true costs.

"That really distorts the market."

Roberts and Turner said the environmental groups are still considering next steps, including whether to file a request for rehearing. ■

MISO News

Illinois Regulators Open NOI on Ameren MISO Membership

Study: Illinois Would Lose Billions if MISO Utilities Left for PJM

By Amanda Durish Cook

The Illinois Commerce Commission last week instituted a Notice of Inquiry over the potential benefits of Ameren Illinois quitting MISO to join PJM.

The ICC's NOI focuses on a recent Ameren Illinois *study*, prepared by Charles River Associates, which concluded that if all MISO Zone 4 utilities left for PJM, it would cost the State of Illinois $3.4 billion over the 10-year period from 2025 to 2034 (*23-NOI-01*). The firm recommended Ameren Illinois stay on with MISO after it analyzed energy trade benefits, transmission expansion costs, capacity costs, RTO administrative fees, and exit and integration fees.

"Joining PJM did result in some benefits, such as reduced emissions and increased resiliency, but these benefits are outweighed by the significant economic costs," the study authors wrote.

Ameren commissioned the cost-benefit analysis at the behest of the ICC last July after MISO's 2022/23 capacity auction unearthed a 1.2-GW shortfall across its Midwest region. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*; *MISO Reacts to Ill. Legislators' Criticism of Capacity Shortfall*.)

"Safe, reliable and affordable electricity is always top of mind at the commission, and with the ongoing changes to our power system, it makes sense for the ICC to consider how the workings of our electric grid operators are or are not benefiting Illinois consumers," ICC Chairman Doug Scott said in a press release. "This study is a helpful resource in determining if continued participation in MISO makes the most sense for Illinois and Ameren Illinois customers."

Construction of an Ameren Illinois substation | *Ameren Illinois*

The ICC said that without reform, "structural market shortcomings" in MISO could lead to insufficient supply and a spike in bills for ratepayers in central and southern Illinois.

ICC's NOI includes a three-month comment period for interested parties, with initial stakeholder comments due Oct. 2 and reply comments due Nov. 1.

The ICC said comments will "inform any future or potential commission action regarding the state's ongoing participation in its two power grid operators." The ICC emphasized that its NOI proceeding is not a rulemaking. It said the information it receives "may or may not form the basis for the initiation of a formal ICC rulemaking or other purposes."

On Aug. 3, Ameren reported a profit of $237 million ($0.90/share) for the second quarter, compared with $207 million ($0.80/share) this time last year. It said more significant investments in transmission and distribution infrastructure boosted its fiscal performance.

MISO declined to comment on Ameren Illinois' cost-benefit analysis, whether it thinks the ICC might have a change of heart on its capacity market structure if it adopts changes such as a sloped demand curve, and whether it will file comments in the NOI. ■

MISO News

Renewable Developers Challenge MISO's Lower Congestion Limit

Developers Say Tariff is Unjust, Unreasonable; MISO Cites Cost Sharing, Improved Reliability

By Amanda Durish Cook

A group of renewable energy developers lodged a complaint at FERC last month over MISO's pursuit of a smaller system impact threshold on interconnecting generation, which will induce more network upgrades.

The group of eight developers, including National Grid Renewables, Invenergy and NextEra Energy, said MISO's new rule — which halves some interconnecting generation's allotted distribution factor (DFAX) to 10% — means the RTO is making "sweeping" cost allocation decisions while circumventing FERC approval (*EL23-85*). The grid operator did not run the change past FERC, entering the stricter cutoff into a Business Practices Manual (BPM) rather than its tariff. (See *MISO, Stakeholders Debate Lower Congestion Limit*.)

The new rule applies to MISO's basic and unguaranteed level of interconnection service, called energy resource interconnection service (ERIS). The DFAX, which represents how much a generator impacts transmission congestion, is used to assign the costs of transmission upgrades to ERIS customers. The RTO is applying the more stringent DFAX threshold to customers within certain subregions and at certain transmission voltage levels.

The developers argued that MISO's tariff is unjust and unreasonable because it is silent on cost allocation criteria for interconnection customers. They asked FERC to order MISO to revise its tariff to incorporate the previous 20% DFAX standard and only allow a smaller threshold if the RTO makes a formal proposal before the commission with evidence that the change is reasonable and necessary.

The developers argued that the Federal Power Act and FERC policy require that MISO keep its cost allocation criteria for interconnection customers on file with the commission.

"Should a public utility be permitted to change the cost allocation criteria that it uses to assign interconnection customers hundreds of millions of dollars in costs each year without commission oversight and without complying with the filing requirements of the FPA?" the developers asked rhetorically in their July 25 complaint. "MISO's use of a BPM to make drastic changes to its cost allocation criteria reflects a fatal defect in MISO's tariff: The tariff does not include the cost allocation criteria applied by MISO to determine the rates that a customer must pay to obtain interconnection service."

MISO has said the lower tolerance on congestion contributions will allow upgrade costs to be shared among more interconnection customers and result in fewer unaddressed reliability issues passed on to later queue cycles or turning up in the RTO's annual transmission expansion plans.

But the developers contended MISO has flouted statutory requirements by dodging the filing process on a proposal that will "materially affect the costs that customers are required to pay to obtain interconnection service and access the wholesale markets." They said it didn't respond to stakeholders' requests that it justify its proposal.

"Although MISO may believe that a selectively applied 10% standard represents an improvement over prior practice, the only standard that has been shown to be within the range of reasonableness is the longstanding 20% standard. MISO has not provided any empirical data that shows the 20% DFAX standard is unjust, unreasonable or unduly discriminatory," the developers said.

They also charged that MISO's goal is reducing congestion for the sake of economics, not supporting reliability. The RTO should also employ a DFAX threshold uniformly, the developers argued. ■

MISO Wraps Incident-free June

Average Load Fell; Real-time LMPs Plummeted

By Amanda Durish Cook

MISO presided over routine operations in June, with an average 81-GW load and diminished wholesale prices.

Average load was down 3 GW compared to June 2022. MISO's real-time locational marginal prices fell more dramatically, from about \$75/MWh to \$28/MWh year over year. Most of the drop was attributed to natural gas prices falling from about \$8/MMBtu to \$2/MMBtu within the year.

Average daily generation outages also were lower than last June, at about 38 GW instead of 41 GW. MISO operated with a fuel mix of 44% natural gas, 29% coal, 15% nuclear and 9% wind.

The grid operator realized a 3-GW solar peak June 20, when solar generation served 3% of total load at midday.

Heat arrived in the latter half of the month, forcing multiple rounds of conservative operations instructions and MISO's 111-GW peak on the evening of June 29. The monthly peak was 10 GW short of last June's peak.

MISO said it will internally review a more than 7% error in its load forecasting for June 29. The grid operator attributed the load estimate error to severe weather in the footprint's central region that ultimately shaved 10 to 20 degrees from initial weather forecasts.

So far, summer hasn't held any emergency procedures for the footprint. MISO managed to avoid a maximum generation emergency last month during a systemwide heat wave. (See *MISO Preps for Heat Wave, Anticipates Annual Demand Peak*.)

MISO ultimately issued two separate maximum generation alerts for its Midwest region two days before the expansive heat wave intensified July 27 and again July 28. Those followed MISO's issuance of conservative operations instructions, a hot weather alert and a capacity advisory July 23.

The grid operator said July 25 that it was facing risks from above-normal temperatures and forced generation outages. It had warned that its forecasted high loads could have caused it to come within 500 MW of its operating obligations for July 27.

"With increased risk and uncertainty, it may be necessary for MISO to escalate further based on changing system conditions," MISO said at the time. ■

NYISO News

FERC Sets Niagara Mohawk Transmission Rate for Hearings

National Grid Subsidiary Sought Special Rates for its Share of Public Policy Line

By James Downing

FERC on Friday partially approved new rates from Niagara Mohawk for its portions of the AC Transmission Public Policy Transmission Project, which is designed to increase transfer capability across central east New York.

To pay for its share of the project (LS Power and the New York Power Authority are building most of it), the National Grid subsidiary proposed to include a new rate in its transmission service charge, called Rate Schedule 20.

The project, which is expected to be completed later this year, includes changes to some of Niagara Mohawk's facilities. The firm plans to spend between $38 million to $55 million upgrading a substation and reconductoring some transmission.

FERC accepted the firm's cost-allocation proposal, which is in accordance with the 25/75 method used in NYISO where 75% of the costs go to zones that directly benefit from such lines and the last 25% is allocated across the entire market.

The much larger, $1.2 billion project mostly involves new infrastructure, but utilities retain the right to add any upgrades to their systems required by such projects. While FERC already had found that utilities had that right back in 2019, the NYISO tariff did not include language to implement generally, so the developers executed the "Segment A" agreement with Niagara Mohawk to make the required upgrades.

The cost-allocation method is in line with what FERC has approved for public policy lines, but the commission said the rest of the proposal has not been shown to be just and reasonable and set the matter for hearing procedures to gather more information.

The charges Niagara Mohawk proposed went into effect Aug. 5 but are subject to change and refunds based on the outcome of the hearings.

The utility said its proposed charges would lead to the same returns on all its other transmission investments under its transmission service charge (TSC). But since its Segment A charges were on top of those, the revenue from it would be credited to the standard TSC to avoid double counting.

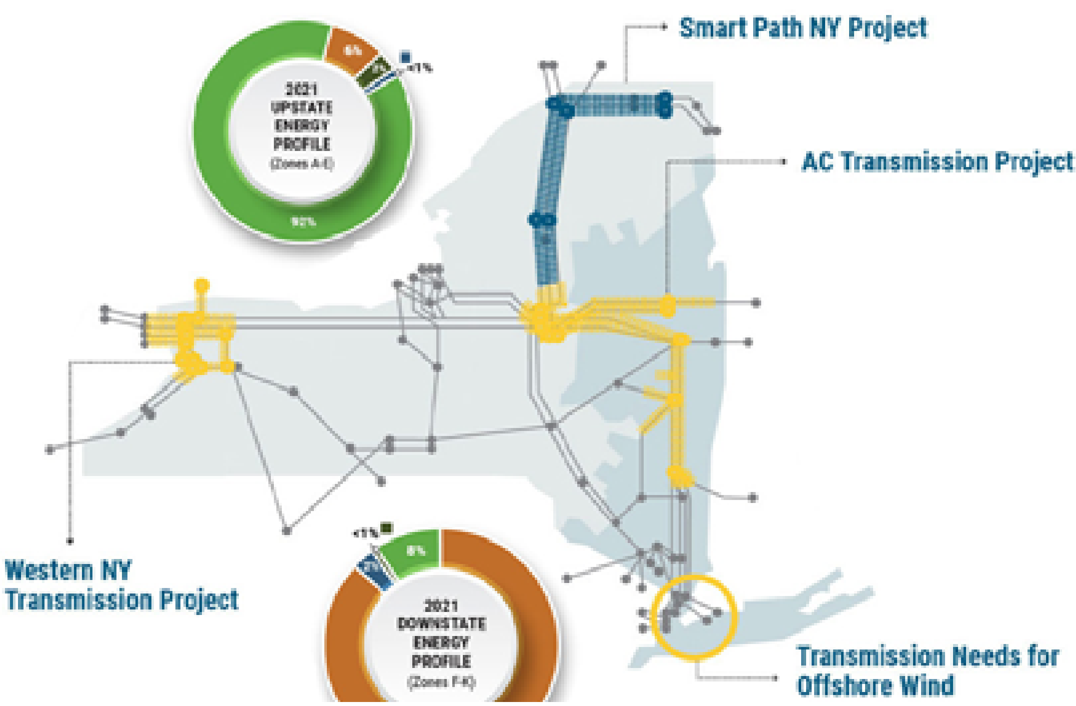
FERC sent a deficiency letter to the utility seeking answers on its proposal, including whether ratepayers would continue to pay a return on investment once the facilities are fully depreciated.

Niagara Mohawk said its carry charge uses average systemwide cost ratemaking, and that leads to ratepayers paying a return as calculated over its useful life. The method is not precise, but the utility said tracking and calculating the costs of specific low-capital assets (like the $38 million it would spend on Segment A) can be administratively burdensome and lead to higher costs for ratepayers.

In the order Friday, FERC still questioned why the carrying charge included retirement obligations, which generally are not permissible in transmission rates. The utility said it would make another filing removing the retirement fees, but FERC said it was not clear whether that approach was appropriate.

The fact that the small segments Niagara Mohawk is building will be recovered using an average of its entire transmission base means that Segment A will never fully depreciate for rate purposes, and the utility failed to show it would ensure its costs are recovered in a systematic and rational manner.

While FERC set the matter for hearing, it encouraged a settlement and will wait to pick an administrative law judge for 45 days to give a chance for settlement talks to occur. ■



| NYISO

NYISO News

NYISO 'Still Digesting' FERC Order 2023

Order Would Financially Penalize Developers for Late Studies

By John Norris

RENSSELAER, N.Y. — NYISO last week shared its first impressions of FERC Order 2023 with stakeholders in a high-level *overview* of the landmark ruling, though it remained reluctant to delve too deeply into how it might impact its work (*RM22-14*).

Thinh Nguyen, NYISO senior manager of interconnection projects, told members of the Transmission Planning Advisory Subcommittee that "we are still digesting all of this information from FERC but plan on coming back to the next TPAS or sooner to discuss this order in more detail."

FERC's July 27 order seeks to unclog backlogged generator interconnection queues by imposing financial penalties on developers whose projects fail to complete studies on time. (See *FERC Updates Interconnection Queue Process with Order 2023* and *FERC Interconnection Rule Sets Penalties, Ends 'Reasonable Efforts' Standard*.)

Stakeholders praised NYISO for how quickly it developed its presentation and acknowledged that the ISO was unlikely to discuss the order in detail, given the timing. But they still pressed staff for as much information as possible during the meeting.

Anthony Abate, lead energy market adviser for the New York Power Authority, asked how FERC's prescriptions will impact the ISO's ongoing work to improve its queue. (See *NYISO Stakeholders Still Questioning Interconnection Queue Proposal*.)

"We're still sifting through this … 1,400-plus page document … but the order is not preventing ISOs or RTOs from reforming their interconnection process procedures, so I think that we could use some of FERC's suggestions, though we haven't mapped all this out yet," Nguyen responded.

Howard Fromer, who represents Bayonne Energy Center, asked how projects currently in the queue would be affected by the order.

Nguyen said "business will continue on as is," with studies underway continuing under the current tariff, but promised to come back with more information. The next TPAS meeting is scheduled for Aug. 21.

Compliance filings are due within 90 days of the rule's publication in the *Federal Register*. In the order, FERC said, "We recognize that many transmission providers have adopted or are in the process of adopting similar reforms to those adopted in this final rule. We do not intend to disrupt these ongoing transition processes or stifle further innovation. On compliance, transmission providers can propose deviations from the requirements adopted in this final rule — including deviations seeking to minimize interference with ongoing transition plans — and demonstrate how those deviations satisfy the standards discussed above, which the commission will consider on a case-by-case basis." ■

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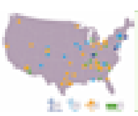

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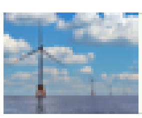

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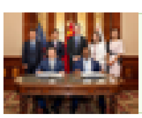

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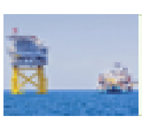

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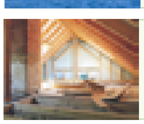

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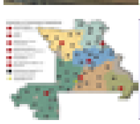

AECI To Pay $42K in NERC Penalties — ERO Insider

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

FERC Approves PJM Change to Emergency Triggers

By Devin Leith-Yessian

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FERC has approved PJM's request to revise its tariff to tighten the triggers for a performance assessment interval (PAI), requiring that a primary reserve shortage be in effect paired with a set of emergency actions (*ER23-1996*).

In its May 30 filing, PJM argued that adding the primary reserve shortage would better align the timing of PAIs with their intended generator performance when it would be most beneficial to reliability. For a PAI to be declared, a shortage would have to be in place as well as a voltage reduction warning paired with any of the following actions: reduction of critical plant load, manual load dump warning, maximum emergency generation action or the curtailment of non-essential building loads and voltage reduction. The July 28 order stated that the changes would provide dispatchers with more certainty during stressed conditions.

The emergency actions necessary for the declaration of a PAI also were reduced to no longer include pre-emergency demand response, which PJM argued should be available for dispatchers to utilize without initiating a full emergency declaration.

"We also find that it is appropriate to remove the deployment of pre-emergency load response and emergency load response from the trigger for a PAI because PJM cannot verify the amount of response these resources are providing until 60 days after an event, and therefore it may be prudent for PJM operators to maintain load response even after capacity shortage conditions pass," the order says. "As PJM explains, its proposed revisions will enable PJM operators to efficiently and effectively operate the grid without second guessing their decision to keep emergency procedures in place during non-capacity shortage instances, such as the hours between morning and evening peaks during extreme winter conditions."

In directing the board to file the proposal, the PJM Board of Managers took one of three components of a package endorsed by stakeholders during the May 11 Members Committee meeting. The other two portions of the package would have based the penalty for resources that perform below their capacity obligation and the annual stop-loss limit on the Base Residual Auction (BRA) clearing price for the locational deliverability area (LDA) that the resource is located within. (See *PJM Board Rejects Lowering Capacity Performance Penalties*.)

Several organizations filed in support of the change to the trigger, but asked that the commission remain open to the possibility of changes to the penalty rate and stop loss in the future.

Though it supported the change to the trigger, the Independent Market Monitor argued that PJM did not make a satisfactory case for not including the full stakeholder-endorsed proposal and suggested that the commission should open a Federal Powers Act (FPA) 206 proceeding to evaluate if the charge rate is just and reasonable.

PJM filed a response stating that commission action is not needed as stakeholders are considering changes to capacity market design, including the penalty charge rate and stop loss limit, through the critical issue fast path (CIFP) process. American Municipal Power (AMP) argued in response that it's unknown what the result of the CIFP process may look like, whether the commission will approve any resulting filing and whether changes will be effective for the next auction.

The latest version of PJM's CIFP proposal, presented during the Aug. 1 stakeholder meeting, did not include changes to the penalty charge rate or stop loss limit.

The Public Service Commission of West Virginia protested the filing, arguing that the change to the trigger would create unbalanced obligations between load and generation. Under the proposed language, it said load will receive voltage reduction and load shedding warnings encouraging consumers to reduce their consumption, but capacity resources will not be notified that they need to be ready for dispatch.

Vitol argued that the tariff revisions would violate the filed rate doctrine and rule against retroactive ratemaking if it were to be applied to auctions that already have concluded. The company stated that market sellers include their expectations about the number of PAIs and how they will impact their generators when forming the capacity performance quantified risk (CPQR) component of their market offers, which goes on to influence their bids and the ultimate auction clearing price.

PJM responded that it is not aware of any unit with a CPQR component that did not clear in either auction which has been concluded for

FERC Approves PJM Change to Emergency Triggers

future delivery years that would be affected by the tariff language, nor did the marginal unit in either auction contain a CPQR component to its offer.

The commission stated in its order that insufficient evidence had been provided that the proposed language would have had any impact on capacity offers. In considering the balance of settled expectations for those auctions, the order states that the commission found that the benefits of more accurately aligning PAIs with stressed grid conditions where generator performance impacts reliability outweighed market participants' expectations based on the emergency action definition.

"There is insufficient record evidence, and no evidence from parties that raise such arguments, that such risk had a material impact on final capacity offers, especially given the other major uncertainties that affect suppliers' assessments of PAI penalty risk, such as weather, fuel availability or equipment failures," the order says.

In supporting the filing, the PJM Power Providers Group (P3) argued that it would allow PAIs to be more reflective of when emergency conditions exist on the grid and avoid "false positives" that have been seen in PJM's history.

The order directs PJM to submit a compliance filing within 30 days to correct clerical errors and capitalize the phrase "Primary Reserve requirement" to more explicitly refer to the parameter defined in the RTO's manuals by the same name.

The Ohio Federal Energy Advocate and Earthrise argued there was ambiguity in PJM's filing around whether the primary reserve requirement by which a shortage is measured against referred to the manual defined reserve requirement or to the broader reserve requirement for primary reserves, which includes the extended reserve requirement. The primary reserve requirement is set at 150% of the synchronized reserve reliability requirement, which itself is based on the single largest contingency on the grid.

Earthrise argued that the filing should be read to refer to the primary reserve requirement without extended reserves and that PJM should be required to make a compliance filing specifying its intent. PJM filed that it preferred to include extended reserves in its definition and included new proposed tariff language in its response.

The commission's order stated that the language of PJM's original filing referred to the primary reserve requirement without the inclusion of extended reserves and its intent or preference to include extended reserves was not reflected. ■

PJM Refines Risk Modeling; Stakeholders Begin Final CIFP Presentations

Performance Assessment Proposal Would Change Penalty Structure, Balancing Ratio

By Devin Leith-Yessian

PJM detailed changes to the performance assessment structure and risk modeling in its critical issue fast path (CIFP) proposal Aug. 1, followed by presentations from Constellation Energy and Vistra.

While an additional meeting has been scheduled for Aug. 14, several stakeholders expressed concern there would not be enough time to get through the remaining stakeholder presentations and hold a dialogue about them before sponsors propose to the board and the Members Committee votes on the proposals Aug. 23. (See *PJM Updates Proposal as CIFP Nears End*.)

Paul Sotkiewicz, president of E-Cubed Policy Associates, questioned if it would be possible to delay the Stage 4 presentation to the board and subsequent MC vote to allow more Stage 3 meetings to be held.

"We're trying to do too much in too short a time, and I just don't see how we're going to get through this all," he said.

PJM Director of Stakeholder Affairs Dave Anders said staff are investigating all the ways of ensuring stakeholders have the information they need to make an informed vote. He told *RTO Insider* that any delay of the meetings would need to be made at least seven days prior to their scheduled date but that PJM would intend to announce any such changes as early as possible to respect stakeholders' travel arrangements.

PJM Modifies Performance Assessment Proposal

Presenting how PJM could measure performance during emergencies and how it would determine penalty charges and bonuses, Pat Bruno said the proposal would retain the current capacity performance framework, while making changes to the penalty structure and balancing ratio and creating a new bilateral trading system.

The proposal would use the same performance assessment interval (PAI) trigger as was included in a filing PJM made in May, which allows an emergency to be declared only when there is a primary reserve shortage, voltage reduction warning and at least one of several additional emergency actions, including a manual load dump warning or maximum emergency generation action. The commission approved the filing July 28.

The penalty rate and stop loss will remain status quo under PJM's proposal. Both were components of a proposal endorsed by the Members Committee in May, but which the board decided not to include in its filing. (See *PJM Board Rejects Lowering Capacity Performance Penalties*.)

Resources' performance in the balancing ratio would be capped at their installed capacity (ICAP) rating, meaning a resource with a capacity obligation of 70 MW and 100 MW ICAP would receive a maximum overperformance bonus equal to 30 MW. The status quo rules do not include a cap.

PJM's Pat Bruno said energy prices likely would be sufficiently high during an emergency to continue to incentivize resources to perform above their ICAP if they are able.

Energy-only and uncommitted capacity resources would be ineligible to receive bonus payments, but the latter would be eligible to take on committed capacity resources' obligations through a new hourly financial capacity trading option. Capacity resources would be able to sell a portion of their obligation to another resource, so long as the buyer had accredited capacity that was not committed. The buyer would be eligible for capacity perfor-

PJM Refines Risk Modeling, Stakeholders Begin Final CIFP Presentations

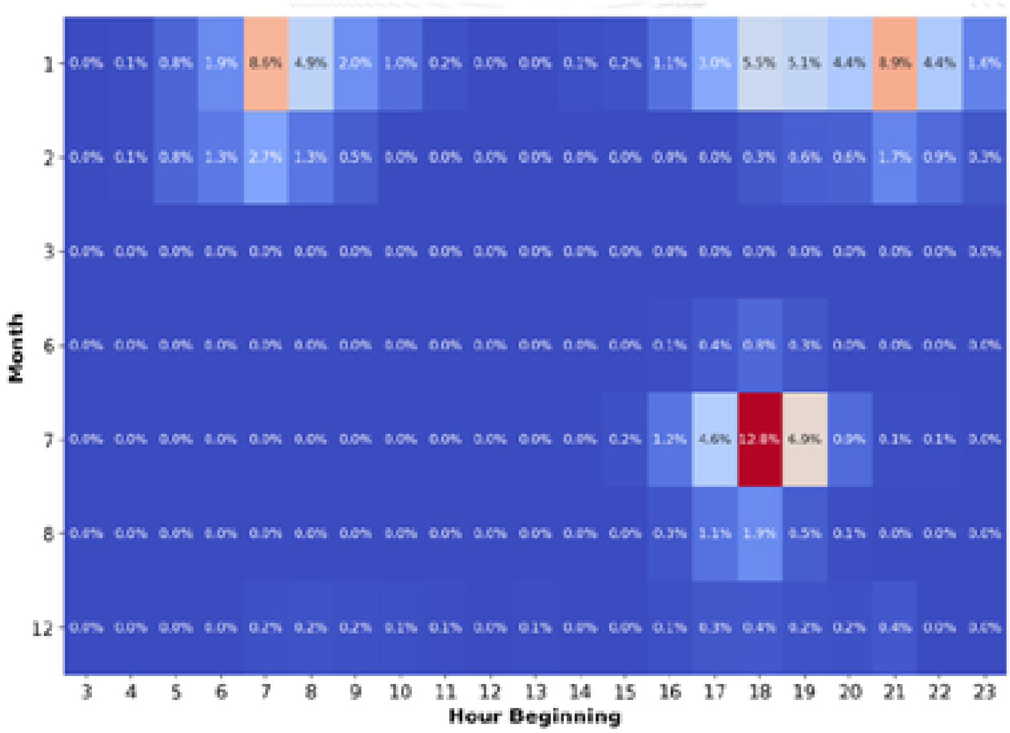
mance bonuses and penalties and the seller would be required to indemnify PJM if the buyer could not perform and could not pay the penalty.

David "Scarp" Scarpignato of Calpine said PJM's analysis of the December 2022 winter storm showed that 70% of the over-performance was from capacity resources and generators. Around 30% was from uncommitted capacity and energy-only resources, which are not eligible for bonuses under PJM's proposed new rules because they are categorically excluded.

Scarp said the "non-committed capacity" resources might find it uneconomical to provide desired emergency energy, especially after the timely gas nomination period has passed.

"I'm not sure you want the uncommitted capacity generator having to make a decision about losing money to help out. The energy market revenues are not enough in some instances, such as when competing for emergency energy imports," he said. "I'm worried that in adhering to PJM's strict 'committed capacity' theory, we're ignoring the reality that the huge quantity of energy-only and uncommitted resources are absolutely needed by PJM for reliability."

PJM also proposed to modify the fixed resource requirement (FRR) penalties by lowering the insufficiency charge from 2 times the cost of new entry (CONE) to 1.75 times net CONE. The daily deficiency charge would be changed from 1.2 times the Base Residual Auction (BRA) clearing price to 1.75 net CONE.



Expected unserved energy (EUE) reliability risk for each hour of the day across the year | *PJM*

PJM Updates Risk Modeling Calculation

PJM's Patricio Rocha Garrido presented updated risk modeling figures focused on where the RTO believes the balance between winter and summer risk lies. The new "base case" the proposal uses is based on weather data going back to 1993, does not include any adjustment for climate change, a proposed change in how demand response and storage are dispatched and updated planned outage data.

The latest modeling places 68% of the annual expected unserved energy (EUE) risk in the winter, with the remainder in the summer. The seasonal risk shifts 56% of the risk to the summer if PJM does not include data from the 1994 winter, which included a particularly severe storm in January.

Previous risk modeling proposals included a longer weather lookback to 1973 and adjusted past weather events with a climate change modifier to account for the expectation that temperatures would be warmer if similar weather occurred in the future. PJM's Walter Graf said the amount of variability PJM saw in the modeling outcomes when implementing the adjustment led it to become less confident in the adjustment.

The new dispatching in the modeling would deploy demand response before storage, which would be ordered so long-duration storage is used before short-duration.

Presenting estimated 2026/27 class average accreditation values, Garrido said storage resources would have significantly higher values during the summer owing to the historical finding that winter outages are likely to be more prolonged. Four-hour storage would have a 90% accreditation during the summer, while 10-hour resources would have 100%; during the winter, however, those resources' values would be 38% and 69%.

Demand response and solar also see large hits to their accreditation during the winter, which Garrido said is because the times at which their contribution is strongest tend to not align with the peak reliability risks for the season.

Showing a heatmap of the hours that tend to have the highest risk for each month, Garrido said the bulk of summer risk is concentrated on July days between 5 and 7 p.m. In the winter, risk is split between around 6 to 10 a.m. and 5 p.m. to midnight in January and a smaller share in February following a similar distribution.

James Wilson, a consultant to state consumer advocates, said he was disappointed PJM did not update the resource mix in the modeling, which he said assumed a large increase in solar, inconsistent with the relatively low summer risk and reliability value in the results.

Wilson questioned why PJM has settled on using 1993 as the date to start its weather lookback and suggested the decision may have been made to include 1994 in the dataset and weight the risk modeling toward winter.

Graf said the year was chosen because it's the starting point for lookback periods PJM uses for other parameters.

PJM News

PJM Refines Risk Modeling, Stakeholders Begin Final CIFP Presentations

Constellation Responds to PJM Proposal

Presenting for Constellation Energy, Adrien Ford said several changes to PJM's proposal would improve the construct, including using a prompt capacity market with a shorter timeframe between the auction and the corresponding delivery year or season, a minimum number of PAIs per delivery year and a rolling 20-year historical weather lookback.

Ford said the company is planning to update its own proposal in the matrix, but last week's presentation was meant to add to the wider discourse around other proposals and design components being considered.

A prompt auction design six months to a year forward of the period the capacity is being procured for would improve the data available to market participants, Ford said. That would include the potential for a more accurate forecast of supply and demand, and reflect changes in the amount of time it takes to build generators.

Ford also said Constellation is considering an earlier capacity performance proposal from PJM where a minimum number of intervals each year would be examined for performance, with the 10 highest load hours each season used to meet the threshold at the end of the year. The changes to the PAI trigger likely will reduce the number of emergencies generators experience, which she said increases the need for regular evaluation of resources' contribution.

Constellation supports PJM's proposal to derive the reliability requirement from EUE analysis, rather than the status quo loss of load expectation and using marginal effective load carrying capability for accreditation.

Vistra Suggests Changes to PJM Proposal

Vistra's Erik Heinle said the company supports much of PJM's proposal but is concerned with several provisions, including limiting bonus payments to committed capacity resources, generators' ability to reflect the risk of being assigned penalties in their market seller offer cap and the ability for the CIFP process to result in an adequately fleshed-out seasonal auction model.

Not allowing a wider range of resources to receive bonus payment for overperforming reduces the incentive for investments that can support reliability and increases the risk for those considering whether to make upgrades to allow them to qualify as capacity resources. If such a resource makes significant reliability upgrades but doesn't clear, Heinle said it would be deprived of both capacity revenue and the opportunity for bonuses.

While he said the hourly capacity obligation trading proposal improves the ability to mitigate risk and improve transparency, he also said more work is needed to ensure that generators can represent all the risks that come with taking on a capacity obligation. The company also supports PJM's decision to maintain the current capacity performance penalty rate and stop loss limit, as well as exempting intermittent and storage resources from offering into the capacity market.

Heinle suggested that PJM include the seasonal capacity model in its filing but delay its implementation to allow more time to allow stakeholders to make changes and understand how the changes would play out. ■

SPP News

DC Circuit Denies Review of SPP Z2 Charges

By Tom Kleckner

The D.C. Circuit Court of Appeals on Friday dismissed a review petition filed by Xcel Energy, on behalf of its Southwestern Public Service (SPS) subsidiary, and Kansas Electric Power Cooperative (KEPCo) over FERC's rejection of their rehearing requests related to SPP's filed-rate doctrine (*20-1429*).

FERC last year denied the SPS and KEPCo rehearing requests of SPP's assignment of network upgrade charges under Attachment Z2 of its tariff. It said the grid operator did not violate the utilities' service agreements or the RTO's tariff. (See *KEPCo, Xcel Rehearing Requests on Z2 Fail*.)

The utilities argued that Attachment Z2 — which awards credits to transmission upgrade sponsors from any upgrade users whose service could not be provided "but for" the upgrade — required using an N-1 contingency analysis, rather than the reservation stack

D.C. Circuit Court of Appeals courthouse | *U.S. Courts*

analysis (RSA) that SPP used. They also said the RTO violated the filed-rate doctrine and tariff because the rate was unclear about how much they would be charged, and because it didn't identify the upgrade facilities that would meet their requests nor provide them with an estimate of the costs.

The D.C. Circuit denied in part and dismissed in part the review petitions because it said FERC correctly concluded that Attachment Z2 "does not plainly require" the N-1 methodology. It also said the commission's reliance on extrinsic evidence to determine SPP's tariff allows the RSA methodology was not arbitrary and capricious, as SPS and KEPCo had alleged.

The court also said it lacked jurisdiction to consider the utilities' filed-rate doctrine argument because they failed to exhaust it at the rehearing stage.

Applying the RSA methodology, SPP imposed upgrade charges in 2016 that had not been specifically mentioned in the utilities' service agreements. SPS was billed $12.8 million for 101 creditable upgrades, 96 of which were not included in its service agreement. KEPCo was billed $6.2 million for seven creditable upgrades; none were included in its service agreement. ■

DC Circuit Rejects Appeal of SPP Zonal Criteria

Petitioners Sought Review of FERC's Approval Order

By Tom Kleckner

The D.C. Circuit Court of Appeals last week denied a petition to review FERC's approval of SPP's tariff revisions setting up a uniform planning criteria in each transmission zone to evaluate zonal reliability upgrades.

The court said Evergy Kansas Central, GridLiance High Plains and Oklahoma Gas & Electric "oversell" the risk that the proposal "will foist the costs of new projects on individual owners" (*22-1252*).

"In any case, FERC may balance the need to ensure that transmission owners bear perfectly proportional costs and benefits with other policy goals," said Circuit Judge Justin Walker, writing for a three-judge panel. "It did that here by approving a regime that allows participants in regional transmission zones to collaborate on selecting and funding new projects."

FERC last year approved SPP's second attempt to establish an annual process allowing each pricing zone to develop uniform planning criteria. The commission affirmed its decision in October when it rejected rehearing requests from Evergy, OG&E, GridLiance and ITC Great Plains. (See *FERC Affirms SPP's Zonal Planning Criteria*.)

Evergy, GridLiance and OG&E appealed to the D.C. Circuit, saying FERC approved an unjust and unreasonable change to SPP's transmission-funding regime. They claimed the methodology would likely force TOs to pay for projects that benefit the entire RTO.

Under a two-step voting process, each zone's customers vote on the criteria, with approval determined by a percentage of votes greater than or equal to the largest customer's load plus half of the zone's remaining load. In the second step, all the zone's transmission customers and TOs vote, with a simple majority needed for approval.

The petitioners said a backup plan that allows any TO in the zone to create its own local planning criteria and build a project — though it would have to foot the bill — violated the cost-causation principle that generally prohibits FERC from "singl[ing] out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse."

The court said that rule "is not rigid" and found that, according to *Consolidated Edison Co. v. FERC*, the commission "may permissibly approve a rate that does not perfectly track cost causation," particularly if it is balancing competing goals.

"That is what FERC did here. [SPP]'s old funding regime let transmission owners unilaterally thrust the costs of new transmission facilities onto customers — whether it benefited them or not," the court said. "When FERC approved [SPP's] new proposal, it balanced the benefit of eliminating that unfairness against the risk that transmission owners might pay for some upgrades alone."

It said balancing competing policy goals on a ratemaking matter is left to FERC's "considered judgment."

The court also denied five additional challenges to FERC's order, saying, "None persuades." ■

Company News

Dominion Earnings Dinged by Issues with Mild Weather and Millstone

Firm's Virginia Offshore Wind Project on Track Despite Issues with Other States' Projects

By James Downing

Dominion brought in $599 million in net income during the second quarter, despite mild weather and some unexpected outages at the Millstone Nuclear Plant in Connecticut, the firm reported Friday.

While Dominion reported on some of the recent issues its business faced, it also said it is wrapping up a business review, with plans to host an investor day by the end of September laying out a new long-term plan.

"I'm pleased with the progress we're making toward delivering a compelling repositioning of our company to create maximum long-term value for shareholders, employees, customers and other stakeholders," CEO Robert Blue said. "As I've said before, I'm as excited as ever for the future of our company."

The second quarter had some of the mildest weather Dominion has seen in half a century, enough to cut into its earnings by 8 cents/share, said CFO Steven Ridge.

"With regard to Millstone, we experienced both an increase to the duration of a planned outage at Unit 2 and an extended, unplanned outage at Unit 3, which taken together amounted to an additional 8-cent headwind during the quarter," Ridge said. "These outages are uncharacteristic for Millstone, which has a strong history as the largest zero-carbon electricity resource in New England, exemplary safety and reliable performance."

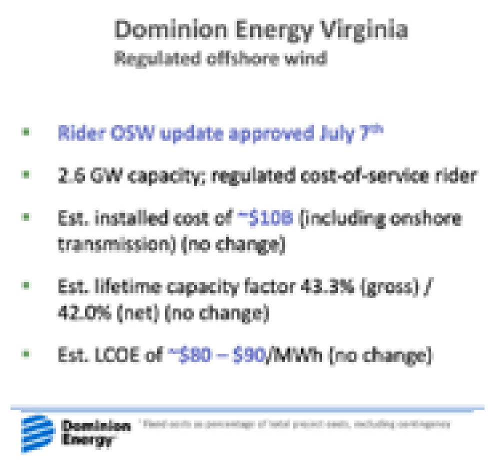
Dominion recently hired Eric Carr from PSEG Nuclear as its new chief nuclear officer, and senior leadership are working on a review of the plant's operating procedures to ensure it is reliable in the years to come, Ridge added.

Dominion Virginia Power last month implemented a rate cut for customers — with the average monthly bill dropping $14 — that was authorized as part of legislation passed earlier this year in Virginia that changed how the utility is regulated. (See *Virginia Legislature Passes Utility Regulation Bills Backed by Dominion*.)

The firm is seeking to spread out recent unrecovered fuel costs to avoid swamping that recent rate cut with a $15/month bill increase, Blue said.

The 2.6-GW Coastal Virginia Offshore Wind project remains on track and on budget, despite some of the issues other major offshore wind developments are running into.

"We continue to work closely with the Bureau of Ocean Energy Management and other stakeholders to support the project's timeline," Blue said. "BOEM received comments from all agencies on the draft of the final EIS [environmental impact statement] and is on schedule to deliver the final EIS by the end of September and the record of decision by the end of October. We continue to be encouraged by the administration's timely processing of offshore wind projects."



| Dominion Energy Virginia

The Virginia State Corporation Commission recently approved an updated rider for the project, which will pay the utility $271 million for its efforts for a year. The project's costs, excluding contingencies, are now 90% fixed, said Blue. Procurement processes are well underway, and the first monopoles should be delivered to the Port of Virginia by the end of the year.

"Despite trends we see elsewhere in the offshore wind market, we do not see anything that changes our confidence in delivering the project on time and on budget," Blue said. ■

Entergy Expanding its Clean Energy Portfolio

Company Expects Further 'Very Strong' Growth

Entergy said Wednesday it is expanding its clean energy portfolio by adding 6 GW of renewable capacity through 2026.

CEO Drew Marsh said the company has almost 2.4 GW of renewable capacity either in construction, permitted, under regulatory review or in negotiations.

"We've been limited by a smaller development pipeline," Marsh told financial analysts during Entergy's second-quarter conference call. "We have been successful with the projects we've been able to put forward. We are finding success in building out our portfolio somewhere in the neighborhood of 4 GW in the pipeline.

"We expect the growth to continue to be very strong, given where we are competitively," he added.

Entergy *reported* earnings of $391 million ($1.84/share), more than double last year's second quarter of $160 million ($0.78/share). Last year's second quarter included operating and shutdown costs for the Palisades nuclear plant, which was sold during the same period a year ago.

Zacks Investment Research analysts had expected earnings of $1.69/share.

"We had a successful second quarter with meaningful progress on key regulatory and legislative fronts," Marsh said in the New Orleans company's press release.

Entergy plans to take advantage of the Texas Resiliency Act, which allows utilities to submit resiliency plans and defines cost recovery options. It plans to file once the Public Utility Commission's rulemaking is complete.

Entergy's Texas subsidiary has filed for approval to increase its annual nonfuel retail base-rate revenue requirement to $1.2 billion — an increase of about $131.4 million (11.2%).

The company's share price gained more than a dollar during the day's trading before closing at $101.40, a gain of 23 cents. ■

— Tom Kleckner

Company News

Constellation Expands Nuclear Clean Energy Matching

Company Touts Partnerships with Microsoft; IRA Incentives also Help

By Devin Leith-Yessian

Constellation Energy championed its nuclear fleet as being ready to match clean energy load when and where it's needed during the company's second-quarter *earnings call* Thursday.

"Our businesses are essential to addressing the climate crisis, and our assets are endurable. The Inflation Reduction Act provides unique opportunities for Constellation and its investors. We believe that we will be able to use nuclear energy to produce hydrogen. We will be able to re-license our nuclear fleet to run at least 80 years without needing to replace it, and the [Inflation Reduction Act] provides, at long last, a long-term commitment that nuclear energy is part of the national security of this great nation," CEO Joseph Dominguez said.

He said value already is being realized through an hourly carbon-free matching *agreement* with Microsoft to use nuclear power sourced from Constellation to reduce the carbon footprint of the company's Boydton, Va., data center. Under the agreement, announced in June, Microsoft will receive up to 35% of its clean energy attributes from Constellation's nuclear capability, allowing the company to procure almost the entirety of its energy from carbon-free sources when combined with other renewables.

The two companies also *partnered* in March to develop an hourly carbon-free energy matching program, which Microsoft will use to track its performance for the new procurements.

Dominguez said he expects more wholesale price volatility and shrinking RTO reserve margins over the foreseeable future, but he believes the company's generation portfolio, helped by the value of its clean energy attributes, positions it well to manage the changing grid.

"Reserve margins are about as thick as they're going to be in these markets, and as you see fossil generation being replaced with renewable generation, the underlying markets are going to be very volatile and it's going to take a special kind of company with a special balance sheet to cover that. I think sustainability solutions also allow us to enter into longer deals with customers that really want that sort of product support," he said.

While wholesale energy revenues were down this year, Executive Vice President Dan Eggers said Constellation thinks that will be offset by the incentives included in the IRA. He also credited the production tax credits with contributing to the company's increased credit rating outlook from Moody's, which went from stable to positive.

"Lower prices were offset by an increase in expected PTCs from plants without existing ZEC [zero-emission credit] programs, reinforcing the downside protection the PTC provides against declining power prices," he said.

In New York, an *agreement* the company has with the New York State Energy Research and Development Authority (NYSERDA) to receive ZECs for its three nuclear generators in the state stipulates that the company will return a portion of the revenue from those credits when federal incentives are available. Gov. Kathy Hochul (D) said the tax credits provided by the IRA will reduce electric rates while maintaining incentives for nuclear production in the state.

Eggers said the company saw significant year-over-year gains in the last quarter, leading it to increase its guidance range from $3.3 billion to $3.7 billion, up from $2.9 billion to $3.3 billion, raising the midpoint by $400 million.

Constellation's Nine Mile Point nuclear plant | *Constellation Energy*

Dominguez said nuclear generation meets all the attributes sought for green hydrogen production and he's confident Constellation's existing nuclear fleet will be eligible for federal incentives for green hydrogen.

"We're having very productive conversations with the administration about means of addressing this from a regulatory standpoint so that existing nuclear can be used to make hydrogen and re-licensed nuclear plants would effectively count too," he said.

Existing generators will be needed to meet the upcoming hydrogen demand, he said, particularly under EPA rules that require gas-fired generators to begin blending hydrogen into their fuel.

Questioned on how the company will prioritize nuclear generation for clean energy credits and producing green hydrogen, he said both can be accomplished at once. For industrial customers looking to decarbonize with hydrogen electrolyzers at their sites, he said they can buy the company's carbon-free certifications and be eligible for federal tax credits for clean hydrogen production.

Executive Vice President Kathleen Barrón said Constellation has been encouraging onshore nuclear fuel production and pushed for the Nuclear Fuel Security Act to be included in the National Defense Authorization Act (NDAA). The U.S. Senate overwhelmingly voted to approve both the amendment and the *NDAA* on July 27.

Constellation's 21-GW nuclear fleet also is to grow following a *deal* to buy a 44% stake in the 2,645-MW South Texas Project nuclear generator announced in June. The announcement says the company anticipates Nuclear Regulatory Commission and Department of Justice approval of the transaction by the end of the year.

Dominguez said the company views natural gas as an important bridge fuel as the nation decarbonizes and it is making investments to reduce emissions from its gas-fired generators, including blending hydrogen into its fuel and developing carbon capture technology. Constellation *announced* in May that it had set an industry record by operating on a blend of 38% hydrogen at its Hillabee gas generator. ■

Company News

Exelon Focuses on Energy Transition, Growth in Q2 Earnings Call

ComEd Ends 3-year Deferred Prosecution Agreement on Bribery Case

By K Kaufmann

Exelon released its *2022 Sustainability Report* in mid-July, and CEO Calvin Butler had top-line figures to crow about during the company's second-quarter earnings call Wednesday.

"We have connected over 200,000 customers with over 3 GW of renewable energy resources, a 16% increase over 2021," Butler said. "We saved close to 25 million MWh in 2022 … a 9% increase that avoided 9.5 million metric tons of greenhouse gases and saved customers over $30 million at our average retail rate."

Butler sees the U.S. energy transition as a major growth driver for Exelon as a pure-play transmission and distribution company, following its separation from Constellation Energy last year, a message that reverberated throughout the call.

"We anticipate investing over $31 billion to support the energy transformation" over the next four years, he said. Also, the *Exelon Foundation* has invested $20 million in companies developing innovative climate solutions, he said.

Other key moves to advance the transition included an announcement that PJM had assigned Exelon utilities $870 million of projects for transmission system upgrades related to the 2025 deactivation of the 1,295-MW *Brandon Shores* coal-fired power plant south of Baltimore.

PJM originally had set and approved the upgrade costs at $786 million, but Exelon has since "refined" the project scope and cost, which is now estimated at $870 million, according to a company email. (See "Brandon Shores Deactivation to Require $786M in Grid Upgrades," *PJM PC/TEAC Briefs: June 6, 2023*.)

Butler also talked up Pepco's new three-year rate plan for its Maryland customers, submitted to the state's Public Service Commission in May.

The "*Climate Ready Pathway Plan*" is aligned with Maryland's goal of reducing its GHG emissions 60% by 2031 and reaching net zero by 2045, Butler said. "The proposal includes over $150 million in climate solution programs to help Maryland meet its goals in the areas of transportation electrification, building decarbonization, beneficial electrification and distributed energy integration."

The 12 programs include a series of "make-ready" incentives — to install wiring or other behind-the-meter infrastructure — aimed at increasing the installation of residential and commercial electric vehicle chargers and supporting building electrification. Grid upgrades and modernization to improve reliability and allow for increased integration of renewables also are part of the plan.

If approved, the plan would add about $5.85/month to consumers' electric bills in 2024-2027, according to Pepco.

Pepco submitted a similar multiyear *Climate Ready Pathway Plan* to the D.C. Public Service Commission in April, with an estimated $6.13 increase in monthly bills. The utility is projecting final decisions from Maryland and D.C. regulators in the second quarter of 2024.

Exelon's other utilities — Delmarva Power in Delaware, Commonwealth Edison in Illinois, Atlantic City Electric in New Jersey, and Baltimore Gas and Electric in Maryland — also have rate cases in progress.

The companies have not experienced any supply chain delays related to transformers or other core system equipment, Butler said in response to an analyst question. The company is able to use its size "to not only access our current suppliers, but identify new ones," he said. "We have not seen a shortage in our transformers. We have not seen a shortage in workforce" that might affect the utility's operations.

EVs, Data Centers to Drive Growth

Though down from a year ago, the company's second-quarter financial results were in line with expectations, Butler said. Exelon posted total operating revenue of $4.818 billion for the quarter, with GAAP net income of $343 million ($0.34/share), compared to $465 million ($0.47/share) in 2022.

Butler had stronger results to report on utilities' performance on industry reliability metrics in outage frequency and duration, with the companies operating "in at least the top quartile." Keeping customers online and getting them back online as quickly as possible if outages do occur "is getting harder to do with storms getting more frequent and severe," he said.

Brandon Shores coal-fired power plant | *Talen Energy*

"But it's increasingly important to do as society depends more and more on electricity" he said. "Nationally, we expect to see 50% annual growth in electric cars and 12% annual growth in data centers … [which] will only strengthen as industries increasingly rely on cloud services and AI."

In other company news, Butler announced that ComEd had reached the end of its three-year deferred prosecution agreement (DPA) with the U.S. Justice Department over 2020 bribery charges against the utility and its former CEO, Anne Pramaggiore.

A federal jury in May found Pramaggiore guilty of bribery in connection with a multiyear conspiracy to pay former Illinois House Speaker Michael Madigan (D) for passage of legislation favorable to the utility. (See *Jury Finds Former ComEd CEO, 3 Others Guilty in Bribery Trial*.)

Also found guilty were former ComEd lobbyist and Madigan associate Michael McClain, former ComEd Vice President John Hooker and former ComEd consultant Jay Doherty.

ComEd pleaded guilty to bribery in a *DPA* in July 2020, agreeing to pay a $200 million fine and cooperate with Justice Department prosecutors for three years. A federal judge dismissed the bribery charges against ComEd last month.

Butler said "the company fully complied with the DPA. … We remain committed at all levels of the company to the highest standards of integrity and ethical behavior, and we look forward to building on the trust of our customers as we continue to move forward." ■

Company News

Eversource Takes Hit on Sale of Offshore Wind Assets

CEO: Company is Committed to Clean Energy, Including Wind

By Jon Lamson

Eversource announced an after-tax impairment charge of $331 million related to the sale of its offshore wind assets in its quarterly *earnings call* last week.

Eversource CFO John Moreira said the impairment "will not have any impact on our cash flows and operations" but noted that the impairment charge could be significantly larger if Eversource is unsuccessful in repricing the Sunrise Wind contract with the New York State Energy Research and Development Authority, or if the Revolution Wind and Sunrise Wind projects do not qualify for investment tax credit adders. (See *OSW Developers Seeking More Money from New York*.)

Moreira estimated these two issues could cost the company an extra $400 million each but said the company is confident it will avoid those costs.

"We have included both of those components in our impairment analysis, and obviously for us to be in a position to do that, there needs to be a certain level of conviction and probability, and on both of those we feel very good," Moriera said.

The $331 million impairment charge amounted to 95 cents/share and contributed to reduced second-quarter earnings of 4 cents/share compared to 84 cent/share in the second quarter of 2022. It largely offset increased earnings in Eversource's electric transmission and distribution businesses.

Eversource previously partnered with the world's largest offshore wind developer, Denmark's Ørsted, to pursue projects off the Northeast U.S. coast, but has decided to exit the partnership and the offshore wind business altogether.

The company completed the sale of its uncommitted lease area to Ørsted in May for $625 million and said it is "near the goal line" on the sale of its stake in the South Fork Wind, Revolution Wind and Sunrise Wind development projects. (See *Eversource Begins Its Exit from OSW Development*.)

The costs and in-service dates for these projects have not changed since May of this year, and about 93% of the costs of the three projects are locked in, Eversource said. The in-service dates range from late 2023 for South Fork Wind to late 2025 for Sunrise Wind.

Eversource CEO Joe Nolan said the company remains committed to clean energy and still sees offshore wind as a key resource for the region despite the recent setbacks.

"We feel very strongly that wind is going to play a major role as we transition to this clean energy environment," Nolan said. "I don't see anyone taking their foot off the gas. The policymakers are very excited about wind, so I really don't see that waning."

He added that Eversource is focused on making the necessary infrastructure improvements to enable the clean energy transition.

"We continue to emphasize the need for system investments to support increased electrification and distributed generation to help ease the current reliance on natural gas generation in the region," Nolan said. ■

WEC Energy Group Touts Expanding Capacity and Load in Q2 Earnings

$1 Billion Microsoft Plan, Natural Gas Work Among WEC Successes

By Amanda Durish Cook

WEC Energy Group executives were optimistic over a new large industrial customer and new capacity additions during a second-quarter earnings call last week.

WEC reported net income of $289.7 million ($0.92/share) for the quarter, slightly more than the $287.5 million ($0.91/share) it earned over last year's second quarter.

"After a down first quarter marked by one of the warmest winters on record, we delivered solid results in the second quarter and we're firmly on track for a strong 2023," WEC Energy Group Executive Chairman Gale Klappa said Aug. 1. (See *WEC Energy Group's Earnings Droop on Mild Winter*.)

The utility is reaffirming its earnings guidance for the year at $4.58 to $4.62/share, he added.

Klappa said WEC is enthusiastic over Microsoft's $1 billion plan to create a new data center campus in its service territory. The complex will be built south of Milwaukee, in the Wisconsin Innovation Park.

"Microsoft has purchased 315 acres … and is moving full speed ahead. In fact, earthwork at the site began just a few days ago. So along with American Transmission Co., we're working closely — in fact, on a weekly basis with Microsoft — to determine the full extent of the energy infrastructure that will be needed to serve this development," he said.

Klappa said he expects Microsoft's new facility to be operational near the end of 2025 at the earliest.

WEC Energy Group CEO Scott Lauber said at the beginning of June, the company closed on its first 100-MW option of the natural-gas fired West Riverside Energy Center for $95 million. He said over the next few weeks, WEC will file to purchase another 100 MW of Alliant Energy's Riverside capacity under its remaining option.

Lauber also noted that WEC placed 128 MW of new natural gas generation in service last month through a $170 million investment to build additional reciprocating internal combustion engines at the Western Power Plant site in northern Wisconsin.

Laubner added that WEC is making progress on the Badger Hollow II solar facility and the Paris and Darien solar battery parks.

"The Badger Hollow II site has begun receiving panels using non-Chinese polysilicon. Also, we continue to work on securing customs release of panels from a bonded warehouse in Chicago. We're still expecting Badger Hollow II to go into service late this year or early next year, with Paris Solar Park to follow. In addition, work has begun on the Darien solar facility, which is planned to go into service in 2024," he told shareholders. ■

Company News

PSEG Touts 'Wins' in Ocean Wind Sale, Energy Efficiency

By Hugh R. Morley

PSEG President and CEO Ralph LaRossa | *PSEG*

Public Service Energy Group marked a number of "wins" that show how the company is aligned with New Jersey's energy policies, including the sale of its portion of the state's first offshore wind project, CEO Ralph LaRossa said during a second-quarter earnings call last week.

LaRossa said the sale of its 25% share of Ocean Wind 1, which closed at the end of May, and other initiatives underway reflect what he sought to do in assembling his management team over the last six months and keeping the utility in line with the New Jersey's aggressive clean energy initiatives. He became PSEG's CEO in September.

LaRossa said he was "very proud" of how the company exited from the offshore wind business.

"We entered, we took a hard look at that opportunity, and we exited in a way that both we were able to keep our heads up financially, policy-wise and with the labor workforce in the state of New Jersey," he said.

LaRossa said in February that the company would leave offshore generation because of its unpredictability but would be "keeping an eye on the market and [seeing] what makes sense." (See *PSEG CEO Says Need for 'Predictability' Drives OSW Sale*.)

Ørsted and other OSW developers have in recent months expressed concern about the rising cost of completing projects because of general inflation, elevated costs for raw materials and transportation and rising interest rates. They also say they cannot execute projects under previously agreed financing deals. (See *OSW Industry Group Sees Growth Beyond Turbulence*.)

Reflecting NJ Policy

LaRossa said another big "win" was the New Jersey Board of Public Utilities' (BPU) approval of the three-year Triennium 2 energy efficiency plan July 26. (See *NJ BPU Backs Building Decarbonization Plan Despite Opposition*.)

Central to the BPU's plan is a series of building decarbonization (BD) "startup" program plans designed to encourage customers of all kinds — but especially residential and multifamily-dwelling customers — to switch from fossil fuel water and space heaters to electric appliances. Another part of the plan details a package of demand response proposals under which customers would reduce their energy use in response to different circumstances. The proposal puts much of the responsibility for enacting the proposals on the state's four utilities.

Parts of the BPU package are similar to existing PSEG energy efficiency measures, and other parts reflect the company's own vision, LaRossa said. He noted that the BPU in May approved a $280 million, nine-month extension for one of the utility's energy efficiency programs that would put it in synch with the start of the Triennium plan in June 2024.

"We stayed aligned with public policy on our energy efficiency filing and [that] took us a good step forward," he said. "As a result of that, we'll really be able to take some advantage of some new orders that came out from the board."

He described the BPU plan as "a good roadmap for all the utilities in New Jersey to follow" and said PSEG is "still studying" the proposals.

"That has a lot of upside for us," he said. "We think [it] will really encourage additional energy efficiency investments from companies like ours," he said.

LaRossa noted that Kim Hanemann, president of the company's PSE&G New Jersey utility subsidiary, is "already actively involved" in the clean buildings working group assembled by Gov. Phil Murphy to study how best to advance electrification in the state. The group "is considering various approaches to building electrification, including the development of a clean heat standard," he said.

"Our overall approach to energy transition is to continue advocating for practical expansion of electrification in a manner which protects customer affordability, safety and reliability," he said.

The approach also includes improving the efficiency of the utility's gas operations, LaRossa said. The company in the first quarter submitted to the BPU a system modernization program that aims to improve the efficiency of its gas system. The plan aims to cut methane leaks by 22%, part of an effort to cut methane emissions by 60% between 2011 and 2030, he said.

He said the various initiatives contributed to a "relatively straightforward quarter" in which the company focused on executing its plans for growth, and "also increasing the predictability of our business."

PSEG reported second-quarter net income of $591 million ($1.18/share), compared to net income of $131 million ($0.26/share) for the second quarter of 2022. Non-GAAP operating earnings for the second quarter were $351 million ($0.70/share), compared with non-GAAP earnings of $320 million ($0.64/share). ■

Company Briefs

Tesla Plans Semitruck Charging Stations Between Calif., Texas

Tesla last week requested $97 million in federal funding to build nine electric semitruck charging stations between California and Texas.

Each charging station would be equipped with eight 750-kW Megachargers and four chargers designed for other electric trucks.

Tesla would contribute $24 million to the project.

More: *Electrek*

Tesla Faces California Class Action on EV Range Claims

Three Tesla owners in California last week sued the automaker in a proposed class action lawsuit that accuses the company of falsely advertising the estimated driving ranges of its EVs.

The lawsuit cites a *Reuters* article published two weeks ago that reported Tesla had created a "diversion team" in Nevada to cancel as many range-related appointments as possible after becoming inundated with complaints. The plaintiffs cite occasions when their Teslas didn't achieve close to their advertised ranges and had complained to the company without success.

More: *Reuters*

Broad Reach Closes Financing for Batteries

Broad Reach Power last week announced it has closed $435 million in credit to support the construction of seven standalone storage projects totaling 880 MW in Texas and California.

The projects, which include 825 MW in ERCOT and 55 MW in CAISO, are expected to become commercially operational between late 2023 through Q1 2024.

More: *Broad Reach Power*

Federal Briefs

Lab: Repeated Fusion with Higher Yield

Researchers at the Lawrence Livermore National Laboratory say they repeated nuclear fusion for a second time on July 30 with an even higher energy yield than their first attempt in December.

Researchers have produced fusion reactions before, but it has taken more energy to cause the reaction than the amount produced. The key with the two LLNL experiments is that the energy produced has outpaced the energy put into the event.

More: *The Washington Post*

DOE Will Pay to Remove Carbon from Atmosphere

The Department of Energy is reportedly preparing to pay companies to remove carbon dioxide directly from the atmosphere with a first-of-its-kind program.

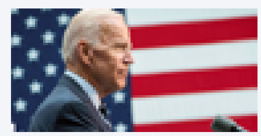
The program, which is expected to be announced shortly, was approved by Congress last year in a 2023 appropriations law that told the DOE to "establish a competitive purchasing pilot program for the purchase of carbon dioxide removed from the atmosphere or upper hydrosphere." In February, it requested public input for a plan to provide "demand-side support for clean energy technologies," including for "carbon dioxide removal."

A spokesperson for the department declined to comment.

More: *Heatmap*

Biden Expected to Create National Monument to Block New Mining

President **Joe Biden** is leaning toward designating a vast area near the Grand Canyon as a national monument to safeguard it from uranium mining, according to people familiar with the plans.

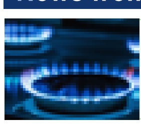


Leaders of local tribes and environmentalists have spent years lobbying to protect areas near the park from potential uranium mining. Federal officials have started telling tribal and environmental groups to be available for a potential Grand Canyon announcement this week, which would fall during Biden's travel. It is not yet clear what the borders will be for the designation, but Biden officials in recent weeks have signaled support for the proposal.

Uranium mining officials said they will explore ways to fight the decision.

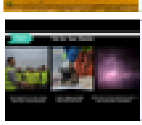
More: *The Washington Post*

News from our other channels



NJ Plans for Transition Away from Natural Gas NetZero Insider

NREL Study Finds Wind, Solar Setback Regs Proliferating NetZero Insider



RF Workshop Hears Lessons from 'Close Calls' ERO Insider

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

State Briefs

ALABAMA

EPA Poised to Reject State's Coal Ash Management Plan

EPA last week said it is poised to reject Alabama's proposal to take over coal ash regulation, saying the plan does not do enough to protect people and waterways.

The agency said it identified deficiencies in the Department of Environmental Management's permits with closure requirements for unlined surface impoundments, groundwater monitoring networks and corrective action requirements.

More: *The Associated Press*

CALIFORNIA

Vistra Completes Moss Landing Expansion

Vistra last week announced it has completed the 350-MW Phase III expansion of its Moss Landing Energy Storage Facility, bringing its total capacity to 750 MW.

The Phase III project, which is made up of 122 individual containers that house more than 110,000 battery modules, was completed on schedule on June 2 and within budget in 16 months.

The facility will operate under a 15-year resource adequacy agreement with Pacific Gas and Electric beginning Aug. 1.

More: *Vistra*

DELAWARE

Carney Signs Package of Environmental Protection Bills

Gov. John Carney (D) last week signed seven environmental protection bills into law, including the Delaware Climate Change Solutions Act, which provides a framework for establishing and achieving the state's environmental protection goals.

Two other bills signed also address EVs. One establishes an annual target and long-term plan for purchasing electric school buses, while another focuses on developing a more comprehensive EV charging infrastructure. Another bill requires new commercial buildings of 50,000 square feet or more to be able to support solar energy infrastructure, and a fourth focuses on developing a plan to procure offshore wind power.

More: *Delaware Public Media*

GEORGIA

EPD Names Jeff Cown as its Next Director

Jeff Cown will become the next director of the state's Environmental Protection Division, effective Aug. 16.

Cown was nominated by Gov. Brian Kemp (R) to replace Richard Dunn, who is now the director of the governor's Office of Planning and Budget. The Board of Natural Resources then met briefly during a special meeting to unanimously confirm Cown.

More: *Georgia Recorder*

INDIANA

NIPSCO Bills to Increase to Pay for Renewables

Northern Indiana Public Service Co. customers will soon see an increase in their electric rates, which are about to go up by about $12 a month.

The state recently approved the increase to help pay for new renewable energy projects, as well as maintaining the company's coal plants. NIPSCO's Schahfer coal plant was originally supposed to shut down this year, but the company said solar supply chain shortages meant they had to keep the plant online for another two years.

More: *Lakeshore Public Radio*

IOWA

Navigator CO2 Ventures Sues Story County over Pipeline

Navigator CO2 Ventures last week sued Story County, asking a federal judge to block its efforts to regulate the project.

In mid-May, the county's Board of Supervisors passed an ordinance establishing setback requirements that directly conflict with the pipeline's proposed route and would limit the route the Utilities Board could approve. Navigator claims the ordinance not only usurps federal and state regulatory powers over carbon dioxide pipeline construction, but also superimposes the county's preferences for the project over other counties, the utilities board and citizens.

Navigator and a group of affiliates are developing the $3 billion Heartland Greenway Pipeline System that calls for 900 miles of steel pipe to be laid in 33 of the state's 99 counties. The pipeline would transport carbon dioxide waste from ethanol plants.

More: *Iowa Capital Dispatch*

NEBRASKA

Milligan 1 Wind Farm Files Action Against Saline County

The operator of the 99-turbine Milligan 1 wind farm is seeking temporary and permanent injunctions against the Saline County Board of Adjustment for creating a sound limit on the turbines five years after they were built.

Attorneys for the farm contend the county board used a "meritless citizen complaint to invent and enforce a sound limit that was not a part of its original conditional permit." On July 25, the board voted to create a sound limit that could not exceed 50 decibels within 1,000 feet of a complainant's property or cease operations.

Saline County District Judge David Bargen asked attorneys for Milligan 1 and Saline to draft an order for his consideration.

More: *News Channel Nebraska*

NORTH DAKOTA

PSC Denies Siting Permit for Summit Carbon Pipeline Project

The Public Service Commission last week denied a siting permit for the Midwest Carbon Express CO2 Pipeline Project.

The PSC said it felt that Summit has not taken steps to address outstanding legitimate impacts and concerns expressed by landowners or demonstrated why a reroute is not feasible. The commission also requested additional information on several issues that came up during hearings, but Summit either did not adequately address these requests or did not tender a witness to answer the questions.

SCS Carbon Transport filed an application last October to construct a 320 miles of

State Briefs

carbon dioxide pipeline that would have crossed through parts of 10 counties.

More: *North Dakota Public Service Commission*

OHIO

FirstEnergy Facing Organized Crime Probe from AG's Office

The state's Organized Crime Investigations Commission is investigating FirstEnergy Corp. in connection with the company's admission of bribing former House Speaker Larry Householder and PUC Chairman Sam Randazzo.

FirstEnergy disclosed receiving a subpoena on June 29 in a financial report filed last week. The company said it was not aware of the investigation, which focuses on FirstEnergy's conduct it admitted to in a 2021 deferred prosecution agreement it entered with federal prosecutors.

More: *Cleveland.com*

SOUTH CAROLINA

Judge Dismisses Charges Against ex-Westinghouse Exec

V.C. Summer nuclear plant | *South Carolina Electric & Gas*

U.S. District Judge Mary Geiger Lewis last week ruled that several grand jurors who voted to indict former Westinghouse executive Jeffrey Benjamin on mail and securities fraud charges were potentially biased because some were ratepayers.

"Benjamin is entitled to a grand jury free from his alleged victims," Lewis wrote in her order dismissing the case.

Prosecutors said top Westinghouse officials knew the VC Summer nuclear project was sunk long before its cancellation, yet hid damaging information from SCE&G and Santee Cooper to keep the deal alive. They claim Benjamin oversaw the projects and played a key role in the fraud.

More: *The Post and Courier*

TEXAS

CPS Energy to Seek RFPs for Major Community Solar Expansion

CPS Energy will launch a request for proposals for up to 50 MW of additional community solar arrays by the end of August, utility officials told CPS Energy's Board of Trustees last week.

The additional capacity will allow San Antonio residents who live in rented homes, apartments, duplexes or other multifamily housing units to have access to solar benefits. CPS Energy already has three community solar projects that were launched in 2015, 2016 and 2018.

More: *San Antonio Report*

VIRGINIA

Dominion Program to Cap Low-income Bills to Start this Year

A state-mandated program to cap electric bills for eligible low-income Dominion Energy customers is set to start by the end of the year, filings at the State Corporation Commission show.

The Department of Social Services estimates about 45,000 customers will participate in the program, while Dominion will need $68.2 million to cover the difference between what they pay for their power and what it costs the company to deliver it. It said it will also need $2.4 million to cover the state costs for its role in the program and $2.1 million for its own administrative expenses. To raise that total of $72.7 million, Dominion is proposing a surcharge that would amount to 76 cents a month.

The program would cap the participants' bills at 6% of income for those who do not use electricity to heat their homes and 10% for those who do.

More: *Richmond Times-Dispatch*

State Officially Exits RGGI; Groups Appeal

The state officially withdrew from the Regional Greenhouse Gas Initiative (RGGI) on July 31, as the withdrawal was published in the Virginia Register with a goal of a full exit by the end of 2023.

Shortly after winning the 2021 gubernatorial election, Glenn Youngkin (R) announced his intention to pull out of RGGI.

As a result, the Southern Environmental Law Center filed an appeal on behalf of a coalition that includes Appalachian Voices, the Association of Energy Conservation Professionals, Faith Alliance for Climate Solutions and Virginia Interfaith Power and Light.

More: *The Hill*

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