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1200 Pennsylvania Avenue, NW
Washington, DC 20460

Comments on Grid Reliability in Response to EPA's Supplemental Notice

America's Power submits the following comments on the Supplemental Notice of Proposed Rulemaking to the Carbon Rule that the Environmental Protection Agency (EPA or Agency) has proposed for regulating carbon dioxide (CO_2) emissions from certain fossil-fueled power plants (Supplemental Proposal) under section 111 of the Clean Air Act (CAA).[i] In addition to seeking comments on small business impacts of the Carbon Rule, the Agency is requesting comments on ways to address potential adverse electric grid reliability impacts resulting from the Carbon Rule. Please note that America's Power filed comments on the Carbon Rule in May which we incorporate by reference. Those comments explained our concerns about the rule, which included threats to grid reliability.

By way of background, America's Power is the only national trade organization whose sole mission is to advocate at the federal and state levels on behalf of coal-fired electricity and its supply chain because both are essential to maintaining grid reliability. Our membership includes electricity generators, coal producers, barge operators, and equipment manufacturers.

Brief Summary of America's Power Comments

- Coal retirements are increasing the prospect of an electric reliability crisis. Already, utilities have announced plans to retire some 81,000 megawatts (MW) of coal-fired generation (almost half the existing coal fleet) within the next six years.
- As currently designed, the Carbon Rule will cause even more coal retirements, further exacerbating reliability risks. We estimate that more than 100,000 MW of coal are at risk of retiring prematurely because of the Carbon Rule's requirements to limit capacity factors, co-fire substantial amounts of natural gas, or install carbon capture technology by January 1, 2030.
- Various warnings about coal retirements and potential reliability problems extend as far back as 10 years prior to EPA proposing its Carbon Rule. In particular, the North American Electric Reliability Corporation (NERC) has issued at least 21 reports warning of potential reliability problems due largely to the retirement of coal and other dispatchable resources. Despite these warnings, EPA has continued to develop and implement rules that will cause more coal retirements.

- Existing mechanisms, such as reliability-must-run agreements or Department of Energy 202(c) orders under the Federal Power Act, are not adequate to mitigate reliability problems resulting from a large number of coal retirements.
- EPA should withdraw the Carbon Rule and repropose a new rule that corrects the rule's myriad flaws, that is supported by solid reliability analysis, and that does not cause electricity shortages or operating reliability problems.
- Any Carbon Rule should provide maximum flexibility for states to design implementation plans so as to prevent reliability problems. Such flexibility includes allowing states to establish alternate, less stringent emission reduction requirements and compliance deadlines that take into account "remaining useful life and other factors." States should be allowed to implement these measures through an informal and expedited administrative process.

Comments

Overview

The focus of our comments is two-fold. The first is to briefly review the growing electric grid reliability risks which are due largely to the premature retirement of coal and other dispatchable electricity resources. These risks have been highlighted extensively in reports, congressional hearings and correspondence, and two Technical Conferences convened by the Federal Energy Regulatory Commission in November 2022 and 2023. (America's Power participated in both Technical Conferences.) Examples include the following:

NERC reports (examples):

- Annual "*Long-Term Reliability Assessments*" for 10 years (2014-2023);
- Annual "*Summer Reliability Assessments*" for 6 years (2018-2023); and
- Annual "*Winter Reliability Assessments*" for 5 years (2019/2020-2023/2024).
- Note: These total 21 reliability assessments issued by NERC over the past 10 years and 11 over the past 5 years.

Grid operator reports and presentations (examples):

- "*Energy Transition in PJM: Frameworks and Analysis*," December 2021;
- "*Managing Reliability Risk in the MISO Footprint*," June 16 2022;
- "*MISO's Response to The Reliability Imperative*," January 2023; and
- "*Energy Transition in PJM: Resource Retirements, Replacements & Risks*," February 2023.
- Note: MISO and PJM have the largest coal fleets of any of the RTO/ISOs. At the end of 2023, the two had a combined total of more than 93,000 MW of coal. So far, half of their coal fleets have announced plans to retire by 2030.

Congressional hearings and correspondence (examples):

- Senate Committee on Energy and Natural Resources hearing: "Pathways to Lowering Energy Prices," July 2022;
- House Energy and Commerce Committee Letter to EPA Administrator Regan, July 2022.
- House Energy and Commerce Committee Letter to EPA Administrator Regan, April 19, 2023;

- House Energy and Commerce Subcommittee on Environment, Manufacturing & Critical Minerals hearing: "Clean Power Plan 2.0: EPA's latest Attack on America's Electric Reliability," June 2023;
- Senate Committee on Energy and Natural Resources hearing: "Hearing to Examine the Reliability and Resiliency of Electric Services in the U.S. in Light of Recent Reliability Assessments and Alerts," June 2023; and
- Letter from Senators Barrasso and Capito to FERC, November 2023.
- Note: Altogether, the Senate and House have held more than 20 hearings that focused on challenges to grid reliability and the Carbon Rule.

These are merely examples of the warnings EPA should have heeded. The examples show that most of these warnings about the retirement of dispatchable resources and increasing reliability risks occurred prior to EPA's proposal of the Carbon Rule earlier this year. Unfortunately, EPA ignored these clear warnings as it attempts to use the Carbon Rule and other rules to eliminate the nation's coal fleet. **If EPA had paid attention to these warnings and conducted proper reliability analysis, there would be no need to issue a Supplemental Proposal at the eleventh hour.**

The second is to identify possible actions that EPA should take to reduce reliability risks. To begin with, existing mechanisms are not sufficient to mitigate the likely reliability problems caused by a potentially massive number of coal retirements. (We estimate that 104,000 MW of coal are at risk of premature retirement because of the Carbon Rule.) The most sensible course of action is for EPA to withdraw its Carbon Rule and repropose a new rule that does not undermine grid reliability, as well as correct other legal and technical flaws with the rule.

The other possible but far less desirable approach entails the Agency establishing flexible requirements through an expedited administrative state planning process that allows states to adopt less stringent performance standards and extended compliance deadlines. There are several regulatory measures available to establish flexible state planning rules and processes. As we discuss later, these measures include allowing states to implement plans that establish less onerous performance standards and longer compliance deadlines through subcategorization of the coal fleet and/or establishing a waiver mechanism under EPA's "remaining useful life and other factors" (RULOF) that would enable states to protect grid reliability.

Coal retirements

America's Power has been tracking announced coal retirements for more than a decade. So far, more than 40% (roughly 125,000 MW) of the nation's coal fleet has retired. Past EPA regulations caused or contributed to many of these retirements. As a result, the remaining coal fleet currently totals roughly 188,000 MW, according to EIA.

Announced coal retirements total slightly more than 84,000 MW during 2023-2030. (More than 81,000 MW have announced plans to retire by 2028.) This leaves as much as 104,000 MW of coal at risk of retiring prematurely because of the unrealistic compliance deadline (January 1, 2030) and infeasible compliance options in the Carbon Rule.

A few of these retiring coal units are converting to natural gas. However, reliance on natural gas carries risks, especially supply interruptions and price volatility. In fact, the Carbon Rule and other EPA rules will exacerbate the problems that are described in the recent North American Energy Standards Board report about the interdependence between the natural gas and electric sectors and the growing risks associated with natural gas for electric generation.[ii]

We recognize that announced retirement dates are subject to change. For example, the retirement of more than 14,000 MW of coal capacity has been canceled or delayed since last year. Most of these delays or cancellations were due to reliability concerns.

Reliability

NERC defines reliability as both resource adequacy and operating reliability. Adequacy means having sufficient generating capacity to meet peak electricity demand, and operating reliability means "the ability of the Bulk Power System to withstand sudden disturbances, such as electric short circuits or the unanticipated loss of system elements from credible contingencies, while avoiding uncontrolled cascading blackouts or damage to equipment."[iii] NERC's definition of reliability means that any proper analysis of EPA regulations should include impacts on operating reliability, not just resource adequacy.

Operating reliability depends on having the right mix of reliability attributes. Over the course of the past six years, PJM and MISO have identified attributes that are necessary for reliability such as fuel assurance, dispatchability, reactive capacity, primary frequency response, regulation, voltage stability, ramp rate, rapid start-up, minimum downtime, availability in all seasons, energy adequacy, run time limitations, inertia, black start, system stability, and extreme weather performance. No single electricity resource provides all of these attributes. The coal fleet is needed because it provides many of these attributes, including energy adequacy, fuel assurance, seasonal availability, long duration at high output, ramping, inertia, and voltage stability.[iv]

In addition, coal plants have a high accredited capacity that helps prevent electricity shortfalls at critical times. Accredited capacity is a measure of how dependable an electricity resource is when electricity demand peaks. A more dependable resource has a higher capacity value. As an example, the table below shows capacity values that PJM uses for 2026/2027.[v]

	Summer	Winter	Annual Equivalent
Onshore Wind	9%	36%	25%
Offshore Wind	17%	68%	47%
Solar Fixed Panel	18%	1%	8%
Solar Tracking Panel	31%	2%	13%
4-hr Storage	90%	38%	59%
6-hr Storage	97%	48%	67%
8-hr Storage	99%	58%	75%
10-hr Storage	100%	69%	81%
Solar Hybrid Open Loop	53%	11%	28%
Solar Hybrid Closed Loop	53%	11%	28%
Hydro Intermittent	40%	44%	42%
Landfill Gas Intermittent	60%	51%	55%
Hydro with Non-Pumped Storage	97%	82%	88%

	Summer	Winter	Annual Equivalent
Thermals (Overall)	**94%**	**78%**	**84%**
Nuclear	97%	95%	96%
Coal	89%	83%	86%
Gas CC	97%	75%	83%
Gas CT	98%	62%	76%

** Additional thermal class accreditations forthcoming*

	Summer	Winter	Annual Equivalent
DR	109%	73%	87%

** DR values reflect status quo performance windows; assessment of 24-hour availability DR forthcoming*

The coal fleet has maintained an average on-site coal stockpile equivalent to 76 days of normal coal burn and 39 days of full-load burn during the past five years.[vi] Therefore, the coal fleet is not forced to rely on fluctuating weather conditions (wind and sunlight) or just-in-time fuel delivery (natural gas) to produce electricity. For example, coal was able to provide almost half (47%) of the additional electricity that was needed during the height of Winter Storm Elliott in the PJM region. The coal fleet's on-site fuel supplies gave coal plants immediate access to fuel when needed.

Because of its relatively stable and low price, coal is also a reliable option when other electricity resources are not available or are too expensive. For example, according to EIA, average delivered monthly coal prices over the past 15 years have ranged from $1.88 to $2.45/MMBtu; natural gas prices have ranged from $2.04 to $15.73/MMBtu. During that period, coal prices averaged $2.16/MMBtu and natural gas prices averaged $4.39/MMBtu.

Even though EPA rules put virtually the entire coal fleet at risk of premature retirement and increase the prospect of a reliability crisis, EPA did not conduct a proper reliability assessment that would enable the agency and stakeholders to understand and mitigate the impacts of the Carbon Rule on grid reliability.

According to the preamble to the Carbon Rule, "EPA has carefully considered the importance of resource adequacy and grid reliability in developing these proposals and is confident that these proposed NSPS and emission guidelines ... can be successfully implemented in a manner that preserves the ability of power companies and grid operators to maintain the reliability of the nation's electric power system."[vii] However, EPA lacks the expertise and tools to reach such a conclusion, especially one based on NERC's definition of reliability.

Although EPA used its IPM model to project the impacts of the Carbon Rule on the coal fleet and electricity markets,[viii] the agency's modeling results are not sufficient to claim that the rule will not cause adverse reliability impacts. This shortcoming is clearly evidenced by the fact that the IPM model does not forecast reliability impacts. For example, the agency acknowledges that the future electricity supply projected in the IPM reference case "is assumed to be adequate and reliable," even though this assumption conflicts with warnings about the increasing risks to resource adequacy and grid reliability.[ix]

One fundamental shortcoming of EPA's assessment is that the Agency evaluates only "resource adequacy" but not "reliability." As EPA itself recognizes, "resource adequacy . . . is necessary (but not sufficient) for grid reliability."[x] This is because resource adequacy is focused only on ensuring the availability of "adequate generating resources to meet projected load and generating reserve requirements in each power region."[xi] By contrast, "reliability" is a much broader concept that "includes the ability to deliver the resources to the loads, such that the overall power grid remains stable."

According to EPA, IPM is "designed to ensure resource adequacy."[xii] The model projects resource adequacy in the future "either by using existing resources or through the construction of new resources."[xiii] In other words, the model adds enough hypothetical resources to project resource adequacy in the future. That means the model EPA uses will not project a resource adequacy problem. According to the documentation for IPM, "the model determines the location and size of the potential units to build."[xiv] However, there is no assurance that the hypothetical resources that are created by EPA's model will actually be built. Given the well-known difficulty building new electric transmission lines, the same can be said of new transmission created by the model. According to EPA, "... IPM assumes that adequate within-region transmission capacity exists or will be built to deliver any resources located in, or transferred to, the region."[xv]

Quanta Technology has prepared an analysis of the reliability of the PJM grid under certain scenarios. Their report is attached to these comments. PJM was selected because of the availability of data. Quanta conducted the type of analysis that should be the basis for determining whether any policy, especially the Carbon Rule, might cause reliability problems. The analysis is based on 11 scenarios that assume the retirement of fossil generation and the loss of gas-fired generation (similar to Winter Storm Elliott). The results show violation of the 1-in-10 loss-of-load criterion as well load shedding to protect the transmission system. The potential loss of load during extreme winter conditions was projected to be as much as 13,900 MW. Load shedding was projected to be more than 5,000 MW because of equipment failures under winter conditions.

Moreover, electricity load growth is both magnifying the need to ensure resource adequacy and making growth projections tricky. Such growth is due to the ongoing electrification of the economy, concentrated load growth in many areas due to industrial and commercial development, and the increase in electric vehicles. Large industrial loads include data centers, manufacturing centers, hydrogen electrolyzers, and crypto mining. According to NERC, "Growth of large concentrated loads can challenge load forecasting … "[xvi] While PJM forecasts demand growth of 1.4% annually for its footprint over the next 10 years, the grid operator indicates that certain zones will experience demand growth as high as 7% annually.[xvii]

Without knowing the reliability consequences (based on NERC's definition of reliability) of retirements for the IPM reference baseline, it is impossible for EPA to make any credible claims regarding the reliability impacts of coal retirements caused by the Carbon Rule.

Options

As discussed in the prior section, the Carbon Rule would greatly exacerbate the pending grid reliability crisis now facing the nation. An alarming number of coal-fired power plants continue to retire, and the pace of these retirements is faster than EPA seems to realize. This loss of dispatchable generation, which is critically important for assuring electric grid reliability, would greatly accelerate if the Agency moves forward with the Carbon Rule.

The Carbon Rule would require states to adopt CO_2 performance standards for all existing coal-fired power plants and for existing stationary combustion turbines having both an annual capacity factor greater than 50% and generating capacity greater than 300 MW. With respect to existing coal plants, EPA is proposing to set unrealistic CO_2 performance standards and impractical compliance deadlines for four subcategories of coal plants that would pose significant reliability risks.

For example, the Carbon Rule imposes an early retirement deadline of 2032 for coal units subject to a unit-specific performance standard (lb CO_2/MWh) based on routine O&M with no increase in their CO_2 emissions rate above their baseline levels. Similarly, coal units wanting to extend by three years the mandated retirement deadline from 2032 to 2035 must limit their annual operation to a 20% capacity factor starting in 2030. Both of these regulatory options have the effect of forcing premature retirements and production curtailments.

Similarly, the Carbon Rule imposes unrealistic performance standards and compliance deadlines for those coal units that would need to operate beyond 2035 to assure electric grid reliability. In particular, coal units may operate up to 2040 only if the coal unit co-fires with 40% natural gas starting in 2030 or may operate beyond 2040 only if the unit achieves by 2030 a performance standard based on 90% CO_2 capture. The imposition of these stringent control requirements by 2030 effectively prevents coal plants from operating past 2030-2035.

The Carbon Rule suffers from many fundamental legal problems and technical deficiencies that EPA can only fix by withdrawing the proposed rule and reproposing an entirely new rule. An entirely new rule would establish performance standards and compliance deadlines that are practicable and reasonably achievable without causing premature coal retirements that jeopardize grid reliability.

Existing tools

Because the Carbon Rule is so profoundly flawed, there are limits to what can be done to implement the rule and avoid reliability problems by using existing mechanisms. For example, reliability-must-run (RMR) agreements are meant to address temporary transmission security issues caused by a generator retirement. Agreements expire when transmission has been built to remedy a transmission security issue. RMR agreements are not designed to compensate for the retirement of substantial amounts of coal-fired generation, especially without the need for out-of-market payments that distort market prices and put financial pressure on competing resources that are not receiving RMR payments.

Furthermore, RMR agreements do not override or otherwise change the underlying federal, state, and local environmental requirements applicable to a generating unit. As a result, the continued operation of a unit under an RMR agreement puts the owner or operator of the unit at risk to enforcement actions by EPA, states, or environmental groups and the imposition of civil penalties for violating environmental requirements if the unit remains online to assure electric grid reliability in accordance with the RMR agreement. (A paper addressing in more detail the limitations of RMR agreements is attached.)

Another option with very limited usefulness is the issuance of orders by DOE to address immediate, short-term emergency reliability concerns under section 202(c) of the Federal Power Act. However, section 202(c) orders issued to temporarily suspend compliance requirements are not an effective way of assuring electric grid reliability because these orders are intended to mitigate last minute, unexpected emergency situations that are beyond the control of the affected entities or are due to unforeseen circumstances. In addition, these orders are typically granted for only short periods of time (up to 90 days unless extended on a case-by-case basis), which would not allow sufficient time to develop effective and longer-term remedies for reliability problems. Moreover, RMR agreements do not provide longer term certainty required to sustain a healthy supply chain which is also necessary for grid reliability.[xviii]

Brandon Shores, a large coal-fired plant in Maryland owned by Talen Energy, is a case study of the difficult challenges using either RMR agreements or 202(c) orders. The plant had initially planned to convert from coal to oil and continue to operate. However, economics forced Talen to announce plans to retire the plant in 2025. PJM indicated that retirement of Brandon Shores would create reliability problems that could be remedied by adding new transmission, but continued operation of the plant was necessary until such transmission could be added. Talen rejected the possibility of a 202(c) order saying, among other things, that "using coal under a series of ninety-day emergency orders from the Department of Energy is simply not a viable solution [because operating the plant] … requires substantial advance planning, capital expense on fuel and maintenance, and commitments to employees."[xix] To maintain reliability, however, Talen reluctantly agreed to enter into an RMR agreement but only under certain conditions. To date, there has been no final decision to continue operating the plant.

State plans

If the Carbon Rule is not withdrawn, a less desirable option for addressing reliability problems is for EPA to establish a flexible framework for states to develop implementation plans that could mitigate some of the rule's adverse reliability impacts. Clean Air Act section 111(d)(1) allows states "to take into consideration, among other factors, the remaining useful life of the existing source" in the development of their state implementation plans. Similarly, EPA's regulations[xx] allow states to "provide for the application of less stringent emissions standards or longer compliance schedules" due to a variety extenuating factors, including:

- "unreasonable cost of control due to the facility's age, location, or basic process design;"
- "physical impossibility or technical infeasibility of installing the necessary control technology;" or
- "other factors specific to the facility [which could include grid reliability concerns] that make application of a less stringent standard or final compliance time significantly more reasonable."

Referred to as the RULOF waiver, this provision provides states (and EPA) with both statutory and regulatory authority to deviate from the presumptive performance standards and compliance deadlines in the Carbon Rule by taking into account extenuating factors as they develop implementation plans.

As a next step to ensure the adoption of flexible implementation plans, EPA should include requirements in the Carbon Rule that would allow states to consider grid reliability in setting performance standards and compliance deadlines. This could be achieved by authorizing states to develop flexible implementation plans that include alternative compliance schedules, extended deadlines for plant retirements, and less stringent performance standards. Another possible approach could involve the Carbon Rule authorizing states to establish a new subcategory for power plants that need RULOF relief to avoid reliability problems. For plants within this newly created subcategory, the state would have the authority to set performance standards and compliance deadlines to prevent reliability problems otherwise caused by the shutdown of one or more coal plants.

To assure timely action, the Carbon Rule should allow the adoption of these less stringent compliance requirements through an informal, expedited administrative process that would neither require states to formally revise their implementation plans nor EPA to approve those revised compliance requirements through a notice-and-comment rulemaking. Each state's authority to adopt these revisions through an informal process would be based on ground rules established by EPA in the final Carbon Rule.

Under either approach, states would be allowed to develop implementation plans based on reliability analyses performed by grid operators, balancing authorities, state agencies, and other experts through this informal administrative process. To qualify for RULOF relief, states would be required to document the need for reliability relief. This documentation would demonstrate that, without relief, retirement of the unit or units would (1) result in the violation of at least one of NERC's reliability criteria, or (2) cause reserves to fall below the required reserve margin.

This approach would be consistent with EPA's recently finalized section 111(d) implementing regulations for state plans, which EPA states are intended to "improve flexibility and efficiency in the submission, review, approval, revision, and implementation of state plans."[xxi] Furthermore, it falls squarely within the broad statutory authority provided to states in the development of implementation plans tailored to the needs of each state under the "core principle of cooperative federalism" embedded in the Clean Air Act.[xxii]

Further information

We appreciate the opportunity to submit these comments. Please contact either me (MBloodworth@Americaspower.org) or Paul Bailey (PBailey@Americaspower.org) if you have any questions or need additional information.

Sincerely,

Michelle Bloodworth
President and CEO

Attachments: (1) "Ensuring Reliability and Resilience: A Case Study of the PJM Power Grid" and (2) "Reliability-Must-Run Agreements."

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[i] *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (Proposed Supplemental Rule or Proposed Rule). 88 *Fed. Reg.* 80,862 (Nov. 20, 2023). America's Power filed on August 8, 2023, detailed comments on the Proposed Carbon Rule, which is entitled "*New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" and was published in the Federal Register at* 88 Fed. Reg. 33,240 (May 23, 2023).
[ii] "North American Energy Standards Board Gas Electric Harmonization Forum Report," July 28, 2023.
[iii] NERC, "Reliability Terminology," August 2013.
[iv] MISO, "System Attributes Stakeholder Workshop," September 21, 2022, and "Mind the Gap – OMS Resource Adequacy Summit," August 8, 2022.
[v] PJM, Capacity Market Reform: "PJM Proposal, CIFP – Resource Adequacy Committee," July 27, 2023.
[vi] Energy Ventures Analysis, "Coal Stockpile Report," July 2023. Days of full load burn represents a coal plant operating at maximum capacity until its coal stockpile is depleted.
[vii] Carbon Rule at 33,246.
[viii] *See* EPA, "Power Sector Modeling."
[ix] EPA, Office of Air and Radiation, "Resource Adequacy Analysis Technical Support Document," at 3 (Apr. 2023) (Resource Adequacy Analysis TSD).
[x] *Id.*
[xi] *Id.* at 2.
[xii] *Id.* at 3.

[xiii] *Id.*

[xiv] EPA, Office of Air Quality Planning and Standards, "Documentation for Post-IRA 2022 Reference Case," at 4-1 (Generating Resources) (Apr. 5, 2023).

[xv] Resource Adequacy Analysis TSD at 4.

[xvi] NERC, "2023 Long-Term Reliability Assessment," December 2023.

[xvii] PJM, "Energy Transition in PJM: Resource Retirements, Replacements & Risks," Feb. 24, 2023.

[xviii] It should also be noted that EPA proposed in the preamble to the Proposed Carbon rule a mechanism for providing relief from "acute" (short-term) reliability problems. In particular, EPA has proposed to amend the definition of "system emergency" in 40 C.F.R part 60, subpart TTTT and the proposed 40 CFR part 60, subpart TTTTa as part of the Proposed 111 Rules. That definition includes a provision that electricity sold during hours of operation when a unit is called upon to operate due to a system emergency is not counted when determining whether a unit has surpassed the threshold, denominated in terms of the percentage of electric sales, for membership in certain regulatory subcategories. *See* 88 *Fed. Reg.* at 33,333. In the past, EPA has concluded that such an exclusion was necessary to provide flexibility, to maintain system reliability, and to minimize overall costs to the sector. *See* 80 *Fed. Reg.* 64,612. EPA notes that the local grid operator would determine which EGUs are essential to maintain grid reliability, and it solicits comments on whether to amend the definition of system emergency to clarify how that would be implemented. *See id.* While this mechanism may provide some minimal relief from short-term reliability problems by allowing gas peaking combustion turbines to operate at higher capacity factors for short periods of time, it fails to address the major longer-term electric grid reliability problems posed by the Carbon Rule.

[xix] December 7, 2023 letter from Mac McFarland, President and CEO of Talen Energy to Manu Asthana, President and CEO of PJM.

[xx] 40 C.F.R. §60.24(f)

[xxi] 88 *Fed. Reg.* 80,480 (Nov. 17, 2023). Such an approach is similar to the safety valve mechanism that EPA established in the Clean Power Plan (CPP). In the case of the CPP safety valve mechanism, EPA adopted rules that specifically authorized states (and EPA) to apply an "alternative standard" that was less stringent than the generally applicable performance standard during these longer-term electric reliability emergency circumstances for a particular electric generating unit. 80 Fed. Reg. 64,662, 64,878 (October 23, 2015).

[xxii] *Miss. Comm'n on Envt'l. Quality v. EPA*, 790 F.3d 138, 156 (D.C. Cir. 2015); *Am. Lung Ass'n*, 985 F.3d at 420 (reiterating "the importance of allowing States maneuvering room under the cooperative federalism scheme").

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REPORT UPDATE

Ensuring Reliability and Resilience: A Case Study of the PJM Power Grid

PREPARED FOR

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DATE

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Executive Summary

The electric power industry is required to comply with reliability standards established by the North American Electric Reliability Corporation (NERC) and its regional councils. NERC defines grid reliability in terms of 1) resource adequacy, which is the ability of the electric system to supply electricity to end-use customers at all times, and 2) transmission security, which is the ability of the system to withstand sudden disturbances while avoiding blackouts or damage to equipment. Assessing the challenges to compliance with reliability standards should consider not only normal circumstances but also contingencies such as fuel unavailability and greater-than-expected retirements of synchronous generation.

America's Power contracted Quanta Technology to update Quanta Technology's 2018 PJM grid reliability and resilience study[1] (hereafter, "2018 study") to show whether retirements of fossil-fueled synchronous generating units could lead to future reliability problems. The 2018 study used the PJM system as a case study to illustrate the potential reliability consequences of two major risks: increased coal retirements and fuel insecurity. The study showed that the premature retirement of coal-fired generation and the loss of natural gas-fired generation could adversely impact PJM's ability to meet reliability criteria.

This updated study projects a 2023 baseline scenario for PJM and analyzes seven future resource adequacy scenarios and four transmission operation scenarios based on updated information. The updated study determines whether any of these scenarios would show violations of NERC's reliability standards. The study year for the updated study is 2028. Three of the 11 scenarios assume hypothetical measures (hybrid solar and expanded electric transmission) in an attempt to mitigate reliability violations. Insights from the updated study include the following:

- The resource adequacy analysis shows a potential system loss of load of as much as 13,900 MW during extreme winter peak demand. This amount of lost load is based on PJM's accredited capacity values combined with assumed 40,000 MW of fossil retirements and limited availability of 30,000 MW of gas-fired generation under extreme winter weather conditions.
- The transmission security analysis shows equipment overloads that trigger as much as 6,826 MW of load shedding during average winter peak demand. This amount of load shedding is based on assumed fossil retirements.
- Maintaining adequate resources will be a challenge for the PJM system in the future when the grid is likely to be operating under abnormal conditions (e.g., extreme weather).
- Regional electric demand is peaking less in summer and more in winter, presenting a challenge in fueling electric generation during peak winter demand hours.
- Maintaining fuel diversity and understanding the seasonal operating attributes of new and existing resources are critical to maintaining grid reliability.
- Although a 50% increase in intrazonal transmission capacity could avoid a resource adequacy problem, such a substantial increase would likely be impossible by 2028.
- When there is sufficient generation in the summer peak hour, the PJM transmission system would have enough dispatchable generation to help maintain secure transmission operation. However, the situation becomes very challenging during winter, particularly under severe weather conditions.

[1] Quanta Technology, *Ensuring Reliability and Resilience: A Case Study of the PJM Power Grid*, reported for America's Power, April 2018.

This updated study identified four key conclusions:

- First, policymakers and industry must carefully consider if and when existing generation resources can be retired without negatively impacting resource adequacy and secure transmission operations.
- Second, a degree of existing dispatchable generation must be maintained because new technologies (e.g., hydrogen blending for generation and long-duration energy storage) have yet to be proven on a larger scale to be practical and may not be able to perform to the same level as existing dispatchable generation.
- Third, the electric industry needs a better understanding of how extreme weather events and climate change affect power system needs.
- Finally, the nation is electrifying multiple sectors of the economy and with the economy's increasing dependence on electricity, the electric power system must remain reliable and become more resilient.

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1 Introduction

Quanta Technology was contracted by America's Power to update a 2018 PJM grid reliability and resilience study (2018 study) to show whether more retirements of fossil-fueled synchronous generating units would cause reliability problems for PJM. The 2018 study used the PJM system as a case study to illustrate the potential consequences of ignoring two risks: coal retirements and fuel insecurity. These were risks because PJM relies on coal and natural gas for about 70.5% of its electric generating capacity. The 2018 study analyzed nine scenarios to determine whether any of them would result in a violation of industry standards for transmission security and resource adequacy, which are measures of grid reliability. The report concluded that the PJM grid is reliable under capacity oversupply conditions. However, prematurely retiring coal-fired generation and accounting for supply disruptions in natural gas-fired generation could limit PJM's ability to meet reliability criteria for transmission security, resource adequacy, or both under seven of the nine scenarios.

After the 2018 study, the PJM system has been concurrently experiencing fossil generation retirements and renewable generation additions. Similar to what NERC has identified about tightening resource adequacy due to the retirement of dispatchable resources throughout the country for both summer and winter periods[2], PJM has recognized the risks and studied them. In the *Resource Retirement, Replacement, and Risk*[3] report, PJM assumed 40 GW of retirements during 2022–2030, and 60% (i.e., 24 GW) would be coal-fired generation. That is, 53%[4] of the coal fleet would be retired during that period. This situation is close to one of the scenarios in the 2018 study, namely, that half of PJM's coal capacity (about 30,000 MW out of 61,000 MW) was assumed to be retired. However, the anticipated future generation mix calls for an updated understanding of the two essential aspects of grid reliability: resource adequacy and transmission security. Specifically, the updated study (hereafter, "updated study") investigated the resource mix in PJM upon the retirement of 40 GW of coal together with other fossil generation. The updated study then illustrates whether the remaining dispatchable resources and other expected new generation resources could support reliable power grid operations.

Quanta Technology collected generation additions and retirements and then reviewed and updated the PJM resource and transmission models used in the 2018 study. The updated study consists of three tasks:

- Task 1: Updating 2018 Study Models and Assumptions
- Task 2: Resource Adequacy Analysis
- Task 3: Transmission System Security Analysis

The following sections detail the approaches and findings of each task.

[2] NERC, *2023 Long-Term Reliability Assessment*, December 2023.
[3] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, February 24, 2023.
[4] Coal represents 24% of PJM RTO's 187 GW total installed capacity currently. The total coal capacity is about 44.8 GW.

2 Task 1: Updating 2018 Study Models and Assumptions

The latest PJM load forecasts, generation additions, and retirements expected from 2021 to 2030 were used to update the resource adequacy models (PJM's 4R Study Report).[5] Since no significant retirements from 2028 to 2030 have been announced, 2028 was used as the study year. PJM's RTEP 2023 series of power flow cases were used as the topology with updated resource assumptions to update the transmission study; similarly, the transmission study was done for the year 2028. All the assumptions and study methodologies remain the same as in the 2018 study except for the load forecast and resources discussed in this section.

Like in the 2018 study, the PJM resource model was built based on Hitachi's latest PROMOD database, modified according to the information from PJM, and updated for retirement dates based on company announcements and state policies. The resource mixes for 2021 through 2030 are summarized in Table 1. Additional information on the resources can be found in the PJM 4R Study Report (see footnote 5).

Table 1. Resource Mix Summary (Nameplate in MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BESS	209	2,101	2,629	2,629	2,729	2,729	2,729	2,729	2,729	2,729
Coal	43,295	42,103	35,830	34,951	33,022	33,022	29,775	21,963	21,963	20,425
DR	0	6,917	6,917	6,917	6,917	6,917	6,917	6,917	6,917	6,917
Gas	84,911	91,987	101,877	101,019	101,019	100,787	97,861	97,861	97,861	90,971
Hydro	3,091	3,129	3,207	3,252	3,261	3,261	3,261	3,261	3,261	3,261
Nuclear	32,749	32,749	32,749	32,749	32,749	32,749	32,749	32,749	32,749	32,749
Oil	5,810	5,739	4,952	3,943	3,546	3,546	3,538	3,538	3,538	3,438
OSW	162	410	428	1,417	2,690	4,810	9,715	10,315	10,815	10,815
Other	358	358	358	358	358	358	358	358	358	358
PS-Hydro	5,232	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932
Renewable	1,506	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481
Solar	7,300	33,092	42,180	43,679	44,279	44,279	44,279	44,279	44,279	44,279
Wind	11,058	22,887	24,074	24,074	24,074	24,194	24,194	24,194	24,194	24,194
Total*	195,680	248,884	262,614	262,401	262,057	264,065	262,789	255,577	256,077	247,549

Note*: Red highlighted numbers are the total capacity for the PJM RTO for 2023 and 2028, respectively.

Table 2 provides the PJM's load forecasts for the system as well as its 12 zones for the years 2023 and 2028. Notably, a higher forecast load, such as 90/10, is about 7% higher than the average 50/50 forecast.

Table 2. Year 2023 Load Forecast (in MW)

Zone Name	Zone Code	Forecast 50/50	Forecast 90/10	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ratio	Max
APS	1	8724	9334.68	9048	8557	7783	6493	7062	8117	8725	8487	7655	6390	7201	8379	2.94%	9048
AEP	2	22548	24126.36	22497	21312	19508	16343	18378	20794	22328	22019	20147	16190	18184	20774	7.00%	22497
EMAAC	3	31327	33519.89	23713	22498	19807	17525	22836	28899	31724	30537	25733	19606	19154	22708	9.48%	31724
SWMAAC	4	12640	13524.8	11183	10544	9503	7835	9734	11344	12283	11933	10393	8043	8606	10197	3.85%	12283
COMED	5	20417	21846.19	15046	14312	12528	11400	14710	18857	20638	20025	17049	12343	12318	14553	6.18%	20638
DAY	6	3295	3525.65	2939	2780	2582	2201	2616	3009	3267	3188	2856	2223	2397	2747	1.01%	3267
DEOK	7	5249	5616.43	4570	4294	3861	3463	4245	4939	5269	5135	4784	3559	3659	4277	1.60%	5269
DELCO	8	2712	2901.84	2003	1920	1781	1685	2159	2577	2759	2658	2402	1799	1736	1930	0.83%	2759
SOUTH	9	23947	25623.29	24150	22591	20340	17513	19670	21798	23130	23015	20732	17885	19718	22245	9.45%	24150
ATSI	10	11962	12799.34	10097	9727	9168	8090	9670	11557	12349	11900	10548	8167	8664	9764	3.63%	12349
E. PA	11	10215	10930.05	10113	9558	8853	7485	8296	9701	10352	9995	8782	7377	8228	9295	3.16%	10352
W. PA	12	2871	3071.97	2775	2682	2443	2184	2242	2656	2807	2669	2446	2192	2365	2641	0.87%	2807
Total		**162762**	**174155.3**	**138134**	**130775**	**118157**	**102217**	**121618**	**144248**	**155631**	**151561**	**133527**	**105774**	**112230**	**129510**		**157143**

[5] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, February 24, 2023.

Table 3. Year 2028 Load Forecast (in MW)

Zone Name	Zone Code	Forecast 50/50	Forecast 90/10	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ratio	Max
APS	1	9568	10237.76	9245	8745	7899	6539	7087	8076	8769	8519	7726	6474	7340	8459	2.94%	9245
AEP	2	22797	24392.79	22902	21684	19738	16425	18370	20731	22472	22199	20353	16268	18375	21021	7.00%	22902
EMAAC	3	30863	33023.41	24298	23081	19962	17453	22836	28776	31835	30662	25941	19716	19330	23232	9.48%	31835
SWMAAC	4	12520	13396.4	11485	10844	9656	7831	9715	11266	12237	11940	10412	8130	8814	10415	3.85%	12237
COMED	5	20102	21509.14	15226	14499	12493	11244	14387	18546	20223	19719	16694	12112	12196	14597	6.18%	20223
DAY	6	3280	3509.6	2962	2804	2627	2197	2625	2979	3275	3171	2858	2214	2398	2733	1.01%	3275
DEOK	7	5204	5568.28	4684	4403	3953	3523	4299	4996	5382	5219	4883	3619	3734	4331	1.60%	5382
DELCO	8	2702	2891.14	2030	1943	1816	1713	2191	2605	2812	2705	2464	1845	1778	1942	0.83%	2812
SOUTH	9	30768	32921.76	27990	26317	23675	20683	22758	24797	26204	26078	23852	21019	23066	25561	9.45%	27990
ATSI	10	11828	12655.96	10192	9827	9327	8106	9761	11605	12499	12018	10669	8253	8771	9733	3.63%	12499
E. PA	11	10300	11021	10261	9716	8998	7632	8544	9994	10685	10332	8993	7464	8348	9407	3.16%	10685
W. PA	12	2830	3028.1	2769	2678	2403	2139	2214	2638	2808	2672	2425	2175	2344	2619	0.87%	2808
Total		162762	174155.3	144044	136541	122547	105485	124787	147009	159201	155234	137270	109289	116494	134050		161893

Figure 1 provides the location of the PJM zones and member utility companies geographically within each of the 12 zones.

Zones	Utilities	Zone #
APS	AP	1
AEP	AEP, and OVEC	2
EMAAC	AE, DPL, JCPL, PECO, PSEG, and RECO	3
SWMAAC	BGE, and PEPCO	4
COMED	COMED	5
DAY	DAY	6
DEOK	DEOK	7
DELCO	DLCO	8
SOUTH	EKPC, and Dominion	9
ATSI	ATSI	10
E. PA	METED, and PPL	11
W. PA	PENELEC	12

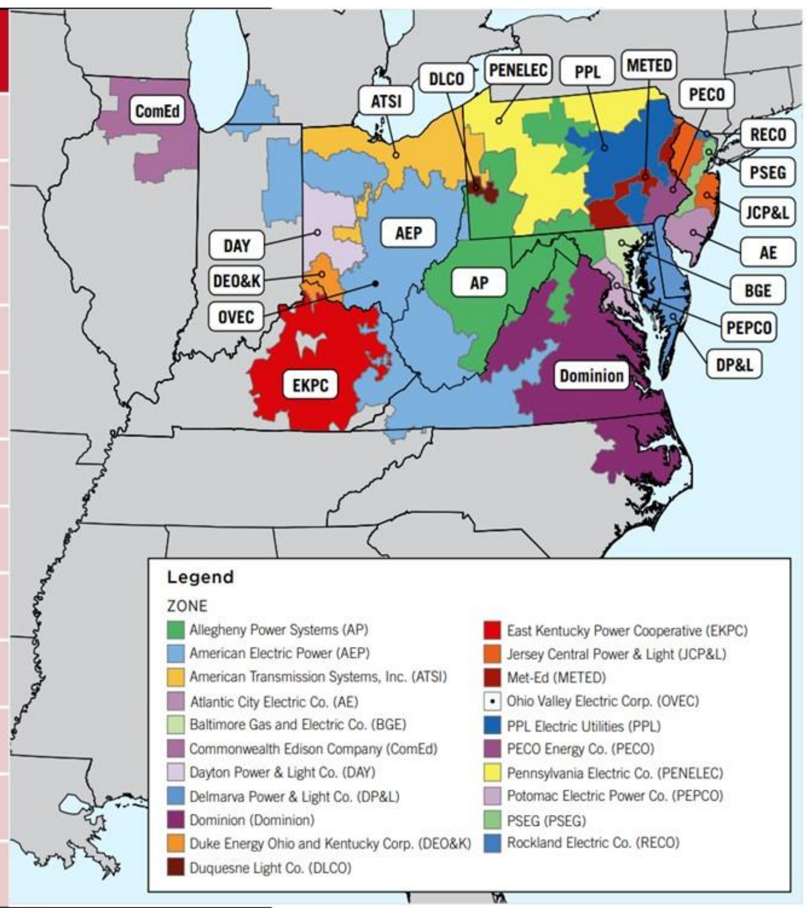

Figure 1. PJM Zonal Map and Member Utility Companies

With the capacity and resource mixes in Table 1 and the forecasted loads in Table 2 and Table 3, the PJM system's resource adequacy measured by loss of load expectation (LOLE) is 0.000002 day per year and

0.000791 day per year for the years 2023 and 2028, respectively.[6] Normal performance means average performance annually, which does not reflect actual performance, for example, during severe winter weather.

PJM intends to improve its resource adequacy modeling and alignment with the eligibility of performance payments in the capacity market. In ER24-99 filed with FERC, PJM updated its risk modeling approach to use a marginal effective load carrying capability (ELCC) for all resources, which recognizes the reliability contributions of respective resources during the hours of greatest risk. While this filing included an annual approach, PJM ultimately intends to move to a seasonal approach, as was discussed in the PJM stakeholder process that led to the FERC filing. During the stakeholder process, PJM studied resource seasonal performance-based capacity accreditation and published the seasonal capacity accreditation values, as shown in Figure 2.[7]

Note that the 22 percentage point derating (97% to 75%) for the gas-fired combined cycle generation and 36 percentage point derating (98% to 62%) for gas-fired combustion turbines from summer to winter reflects gas supply and delivery challenges in the winter season.

The capacity accreditations shown in Figure 2 were used in the updated study to reflect the ELCC values for renewable resources on the left of the figure. Note that solar without DC-coupled, on-site battery storage only has a 1% winter value for fixed solar panel PV and 2% for tracking solar panel PV.

	Summer	Winter	Annual Equivalent
Onshore Wind	9%	36%	25%
Offshore Wind	17%	68%	47%
Solar Fixed Panel	18%	1%	8%
Solar Tracking Panel	31%	2%	13%
4-hr Storage	90%	38%	59%
6-hr Storage	97%	48%	67%
8-hr Storage	99%	58%	75%
10-hr Storage	100%	69%	81%
Solar Hybrid Open Loop	53%	11%	28%
Solar Hybrid Closed Loop	53%	11%	28%
Hydro Intermittent	40%	44%	42%
Landfill Gas Intermittent	60%	51%	55%
Hydro with Non-Pumped Storage	97%	82%	88%

	Summer	Winter	Annual Equivalent
Thermals (Overall)	**94%**	**78%**	**84%**
Nuclear	97%	95%	96%
Coal	89%	83%	86%
Gas CC	97%	75%	83%
Gas CT	98%	62%	76%

** Additional thermal class accreditations forthcoming*

	Summer	Winter	Annual Equivalent
DR	109%	73%	87%

** DR values reflect status quo performance windows; assessment of 24-hour availability DR forthcoming*

Figure 2. PJM Estimated 2026/2027 Class Average Accreditation Value

The lower capacity accreditation values in the winter season (see Figure 2) require the updated study to focus on resource adequacy during the winter months. In fact, from observing the loss of load events over the annual LOLE Monte Carlo simulations, 99% of the risk occurred within a few weeks of the summer period when the load is high and during winter when the high load is combined with fewer resources. The seasonal share of the LOLE is much flatter in the annual study. The observed phenomena further helped shape the

[6] The PJM RTO electric system is planned to meet an LOLE representative of an involuntary load disconnection event not more than once every 10 years, or 0.1 day per year.

[7] Capacity Market Reform: PJM Proposal, July 27, 2023, https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230727/20230727-item-02a---cifp---pjm-proposal-update---july-27.ashx

updated study to investigate 10 additional scenarios primarily for the winter seasons. These scenarios are listed in Table 4.

Table 4. Scenario Definition

#	SCENARIO NAME	DESCRIPTION
	Resource Adequacy	
1.1	Baseline 2023	Resource mix and load for the year 2023 winter; ELCC impact is not considered for gas and coal units.
1.2	Baseline 2028	Resource mix and load for the year 2028 winter; ELCC impact is not considered for gas and coal units.
2	Winter 2028 with PJM latest Capacity Accreditation	Resource mix and load for the year 2028 winter; ELCC impact and capacity accreditation for all resources are considered.
3	Hybrid Solar for Scenario 2	All future solar units are assumed to be paired with battery storage to improve Scenario 2's LOLE in the winter season.
4	Higher Transmission Transfer Capability for Scenario 2	50% higher intrazonal transmission capacity to improve Scenario 2's LOLE in the winter season.
5	Common Mode Outage on top of Scenario 2	30 GW of gas units unavailable during extreme winter weather conditions based on Scenario 2.
6	5 GW of Additional Coal Retirements based on Scenario 2	5 GW of additional coal retirements based on Scenario 2.
7	More Transmission for More Coal Retirements based on Scenario 6	50% higher intrazonal tie-line limits to improve Scenario 6's LOLE.
	Transmission Security	
8	Summer Peak Condition	For the 2028 summer based on Scenario 1.2.
9	Winter Peak Condition	For the 2028/2029 winter based on Scenario 2 before coal retirements.
10	Winter Peak with Resource Retirements	Winter peak condition with assumed resource retirements based on Scenario 2.
11	5 GW of Additional Coal Retirements based on Scenario 6	5 GW additional coal retirements based on Scenario 6.

3 Task 2: Resource Adequacy Analysis

For a control area in the power system such as PJM, its power sources should meet the forecasted demand with possible assistance from neighboring systems under all possible disturbances and contingency conditions. The default assumption in a resource adequacy assessment is that the primary fuel source is always available for generating energy, except when a resource is subject to equipment failure, represented by an equivalent forced outage rate (EFORd). While the reporting and calculation method for the EFORd is the industry standard for measuring annual average generator performance, the updated study also considered seasonal performance differences. This was done by adopting the resource capacity accreditation published by PJM together with the ELCCs for intermittent generation (solar and wind) to capture the true performance of the system resource.

Given the prevailing increased intermittent generation in the overall generation mix, resource adequacy was analyzed under abnormal weather events (i.e., severe winter weather events). Solar, wind, and load profiles, along with intrazonal transmission transfer capability, natural gas interruption, and accelerated coal retirements, created several winter scenarios consisting of hourly data sets for the year 2028. Sufficient transmission transfer capacity is the conduit for firm resource sharing between the zones within the PJM RTO.

LOLEs for the PJM system and the expected loss of load (LOL) in MW are provided in Table 5 for the seven study scenarios.

Table 5. Resource Adequacy Result Summary

#	SCENARIO NAME	CRITERIA MEASURES	
	Resource Adequacy	*LOLE*	*Average System LOL (MW)*
1.1	Baseline 2023	0.000002	0
1.2*	Baseline 2028	0.00079	5
2*	Winter 2028 with Capacity Accreditation	0.243	3,067
3	Hybrid Solar for Scenario 2	0.039	1,068
4	Higher Transmission Transfer Capability for Scenario 2	0.067	1,519
5	Common Mode Outage on top of Scenario 2	2.024	13,909
6*	5 GW Additional Coal Retirements based on Scenario 2	0.633	4,864
7	More Transmission for More Coal Retirements based on Scenario 6	0.235	2,645

* Note: There were transmission security violations under these three Scenarios that were also studied for transmission security as shown in Tables 9 to 12.

The updated study calculated the LOLE for the entire PJM RTO and provided LOLEs for 12 zones within the PJM as an indication of zonal resource strength (see Table 6 and Table 7).

Table 6. System and Zonal Level LOLEs

		LOLE							
Zone Name	Zone # / Scenarios -->	1.1	1.2	2	3	4	5	6	7
APS	1	0.000	0.000	0.000	0.000	0.000	0.083	0.003	0.001
AEP	2	0.000	0.000	0.000	0.000	0.000	0.022	0.004	0.000
EMAAC	3	0.000	0.000241	0.000	0.000	0.000	0.000	0.000	0.000
SWMAAC	4	0.000	0.000513	0.201	0.034	0.036	1.926	0.476	0.096
COMED	5	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DAY	6	0.000	0.000006	0.023	0.002	0.011	0.699	0.175	0.097
DEOK	7	0.000	0.000063	0.127	0.019	0.032	1.569	0.480	0.151
DELCO	8	0.000	0.000020	0.026	0.004	0.007	0.133	0.049	0.021
SOUTH	9	0.000	0.000016	0.105	0.007	0.031	1.213	0.287	0.115
ATSI	10	0.000	0.000334	0.026	0.004	0.002	0.643	0.061	0.004
E. PA	11	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
W. PA	12	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
System Level		0.000	0.001	0.243	0.039	0.067	2.024	0.633	0.235

Note: The LOLE numbers in red indicate violations to the resource adequacy criterion.

Table 7. System and Zonal Level Average LOL (MW)

		LOL (MW)							
Zone Name	Zone # / Scenarios -->	1.1	1.2	2	3	4	5	6	7
APS	1	-	-	0	0	0	79	2	0
AEP	2	-	-	0	0	0	18	3	0
EMAAC	3	-	1.53	-	-	-	0	-	-
SWMAAC	4	0	3.25	1,247	622	588	5,864	1,699	439
COMED	5	-	-	-	-	-	-	-	-
DAY	6	-	0.04	152	30	197	1,337	544	805
DEOK	7	-	0.40	1,055	341	425	3,221	1,756	842
DELCO	8	-	0.13	7	2	4	16	8	5
SOUTH	9	0	0.11	492	37	299	2,772	749	547
ATSI	10	-	2.11	113	36	6	601	103	7
E. PA	11	-	-	-	-	-	0	-	-
W. PA	12	-	-	-	-	-	0	-	0
System Level		0	5	3,066	1,068	1,519	13,909	4,864	2,645

When the ELCCs for renewables are not differentiated between summer and winter seasons, the LOLEs for Scenarios 1.1 and 1.2 are essentially zero, meaning adequate resource reserves for the system in 2023 and 2028. The 5 MW of expected load losses happen during winter months to the SWMAAC (BGE, PEPCO), ATSI, and EMAAC (PSEG, etc.) zones.

When the seasonal ELCCs and capacity accreditations are considered, the system LOLE is at 0.243 for Scenario 2 over three winter months (December, January, and February), meaning a violation of the resource adequacy criterion of 0.1 day per year. The expected load losses are much higher, reaching 1,247 MW in the SWMAAC and 1,055 MW in DEOK respectively; and 3,066 MW for the PJM RTO.

The resource shortfall in the 2028 winter is partially due to the near-zero ELCC for regular solar PVs. Pairing the solar PV with battery storage in Scenario 3 would increase the ELCC from 1–2% to 11%, which is enough to bring the LOLE down to 0.039 and reduce the system-wide expected load loss to 1,068 MW.

Another mitigation means is to increase the intrazonal transmission capacities from resource capacity surplus zones, such as APS, AEP, and ComEd. By increasing the transmission capacity by 50% to allow higher resource sharing between the zones, Scenario 4 shows satisfactory LOLE at 0.067. However, expanding transmission capacity is notoriously difficult, so a significant expansion of transmission is not considered feasible.

Scenario 5 investigated gas unavailability. From a physical and operational standpoint, the electric utility network is highly dependent upon the uninterrupted performance of the gas production and delivery network. Without a reliable fuel source together with the fuel delivery network, the electric system cannot meet its reliability standards. Customers of both gas and electricity systems can suffer when this happens, as demonstrated by the natural gas sector's failure to provide gas for power generation during the two most impactful winters to PJM (2014 Polar Vortex and 2022 Winter Storm Elliott). Because both systems were not designed originally to function as an integrated whole, gas accounted for 72% of outages attributable to fuel during Elliott.[8] Between forced outages, derates, generators not starting on time, and the inability to replenish storage, PJM lost 47–90.5 GW of the generation fleet during Winter Storm Elliott. Indeed, when Scenario 5 assumed the loss of 30 GW of gas-fired generation, the LOLE increased 8.4 times, reaching 2.024, with an expected load loss of 13.9 GW for the PJM system.

Scenario 6 tested a sensitivity to Scenario 2 with an additional 5 GW of coal retirements. The additional retirements push up the LOLE to 0.633. Transmission expansion alone would not improve the LOLE to meet the criterion as shown by Scenario 7.

With the resource adequacy analysis, it can be concluded that before the industry sets natural gas infrastructure reliability rules, overreliance on natural gas-fired generation for resource adequacy and grid operation is unwise and risky. Combined with the unavailability of solar generation during winter peak hours, the system must retain a sufficient level of diversified generation mix until the aspects of reliability and resilience are sufficiently understood and addressed in the era of energy transition.

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[8] *Inquiry into Bulk-Power System Operations during December 2022 Winter Storm Elliott, FERC, NERC and Regional Entity Staff Report*, October 2023, https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

4 Task 3: Transmission System Security Analysis

Transmission reliability issues are identified via power flow studies for both summer and winter peak load conditions. In the updated study, the PJM transmission system with and without the assumed fossil generation retirement was analyzed. Tested conditions included a normal (N-0) condition with all transmission system elements in operation and 40,875 contingency conditions (N-1) with which at least one major facility—such as a transmission line or transformer—was taken out of service to simulate the planned or unplanned outage of transmission system elements. Comparisons of the transmission reliability criterion violations with and without the assumed retirements indicate the level of reliability the retiring fossil plants provide.

For fair comparisons, the updated study used security-constrained redispatch to adjust available generation and controllable transmission facilities (e.g., tap-changing transformers, phase angle regulators, switchable capacitors, and reactor banks) to control local thermal or voltage violations. If overloads still existed after exhausting all redispatch means, load shedding was applied to mitigate the remaining violations. Therefore, the number of violations and the amount of load shed were used as the comparison metrics. Table 8 provides a summary of metrics for Scenarios 8–11.

Table 8. Transmission Security Result Summary

#	SCENARIO NAME	CRITERIA MEASURES	
	Transmission Security	*# Equipment Overloads*	*Mitigating Load Shedding*
8	Summer Peak Condition	30/32*	3,547/3,761*
9	Reference Winter Case	36	3,567
10	Reference Winter Case + Defined Resource Retirements	52	4,708
11	Scenario 10 + 5 GW Additional Coal Retirements	57	6,826

* Note: The numbers before "/" represent before retirement, and the numbers after "/" represent after retirement.

Table 9 provides details on maximum overloads, the number of overloads, and overloaded facilities for Scenario 8 for summer 2028. During the analysis of the single and multiple contingencies that fall within the bucket of the system's N-1 contingencies, certain transmission system overloads were detected. The amount of equipment involved in overloads after contingencies increases from 30 (Scenario 8) to 32 after retiring the fossil generation from Scenario 8. These overloads were primarily linked to significant increases in load, particularly due to new data center facilities. The most severe overloads were pinpointed in the Dominion zone, involving 23 facilities at voltage levels of 230 kV and above. These facilities could experience an overload of up to 55.2% following a contingency in the transmission system.

Notwithstanding the fact that PJM is addressing most of these issues with its Transmission Expansion Advisory Committee, the updated study applied transmission security-constrained dispatch using available generation to minimize the number of overloads. If the overload still existed after the generation redispatch, a minimum amount of load curtailment that was necessary to mitigate the overload was applied and used as the measure for the severity of the transmission security violation. Table 10 lists the amount of generation dispatched for Scenario 8 and Scenario 8 with assumed retirement up to 2028. Specifically, 2,050 MW of generation was redispatched before the 2028 resource retirements; and 2,601 MW was redispatched after the 2028 resource retirements. Since most of the retirements were assumed to be coal-fired generation, the redispatched resources were primarily gas-fired generation units. The severeness of the transmission security violation measured by the amount of load curtailments is 3,547 MW for Scenario 8 (before retirements are assumed) and 3,761 MW after the assumed retirements with Scenario 8, respectively.

With the relatively small incremental increase in the number of overloads, the amount of generation that needs to be redispatched, and eventually the amount of load shed to secure the system, Scenario 8 with resource retirements (coal and gas) would have a sufficient amount of resources in the summer season to keep the transmission security violation to a minimum.

Table 9. Number of Transmission Facilities Overloaded in Summer 2028

Power Flow Model Zone # / Tie Line		Maximum loading [%]		Recurrence of Overloads		Overloaded Equipment	
		Scenario 8	Scenario 8 + Retirement	Scenario 8	Scenario 8 + Retirement	Scenario 8	Scenario 8 + Retirement
215	DLCO	116.3	105.0	1	1	1	1
228	JCPL	103.5	103.5	1	1	1	1
229	PL	116.4	131.3	5	6	1	1
230	PECO	102.0	115.4	4	16	1	4
233	PEPCO	111.4	107.6	4	2	2	2
345	DVP	153.9	153.5	82	70	23	20
229/232	TIE LINE	140.2	155.2	7	6	1	1
230/232	TIE LINE	< 100	104.7	0	4	0	1
232/230	TIE LINE	< 100	107.8	0	3	0	1
TOTALS				104	109	30	32

Table 10. Mitigating Load Shedding (MW) in Summer 2028

Power Flow Model Zones		Load Shedding (MW)	
		Scenario 8	Scenario 8 + Retirements
201	AP	152	0
205	AEP	0	0
212	DEO&K	100	97
227	ME	0	0
229	PL	7	7
230	PECO	61	50
232	BGE	390	1081
235	DP&L	0	0
345	DVP	2788	2473
231	PSEG	0	0
222	CE	49	55
TOTAL		3,547	3,761

In Winter 2028, the system faces a significant challenge due to the early retirements of coal and gas resources as shown in Scenarios 10 and 11. The resulting resource balance is highly limited, making it extremely difficult to meet the load requirements while ensuring transmission security and reliability. The situation becomes even direr in Scenario 11, which incorporates the planned 2028 retirements and an additional 5 GW of coal retirements. This scenario necessitates using 100% of coal generation resources and 97.5% of gas-fired generation plants, leaving little room for dispatchable generation to secure system operation.

Upon analyzing both single and multiple contingencies falling under the N-1 category, the results revealed that the transmission system could face severe thermal overload issues under Scenario 11. Such issues occur when the resulting power flows exceed the thermal limits of transmission facilities, with the maximum load reaching 270.2% of the thermal limit for certain equipment. Again, based on the security-constrained dispatch analysis, some adjustments were made to the generation among the remaining power plants to address these overloads, which mitigated some issues. In cases where the generation redispatch was insufficient, specific loads were shed to mitigate the overloads and to measure the severity of the issues. The results are shown in Tables 11 and 12.

In Scenario 9, 36 equipment overloads were identified within the 230 kV and above voltage level transmission systems. In Scenario 10, after the assumed retirements, equipment overloads increased to 52. In the more complex simulated Scenario 11, considering the 2028 retirements and an additional 5 GW of coal retirements, the equipment overloads rose to 57. The load curtailment required was 3,567 MW in Scenario 9, 4,708 MW in Scenario 10, and 6,826 MW in Scenario 11. Among the affected zones, Dominion Virginia Power, Baltimore Gas & Electric Company, and Allegheny Power experienced the most significant impact in terms of load curtailment.

Table 11. Number of Transmission Facilities Overloaded under Winter Scenarios

Power Flow Model Zone # / Tie-lines		Maximum Loading [%]			Overload Occurances			# of Overloaded Facilities		
		Scenario 9	Scenario 10	Scenario 11	Scenario 9	Scenario 10	Scenario 11	Scenario 9	Scenario 10	Scenario 11
201	AP	< 100	102.7	< 100	0	1	0	0	1	0
227	ME	114.0	134.8	152.2	5	19	26	1	2	2
228	JCPL	102.8	102.8	102.8	1	1	1	1	1	1
229	PL	113.7	134.4	147.4	14	42	63	4	9	13
230	PECO	196.1	239.3	270.2	34	212	227	3	3	3
232	BGE	112.5	127.3	135.3	24	64	106	8	12	15
233	PEPCO	114.0	123.9	122.2	11	13	13	2	2	2
345	DVP	119.3	126.7	123.7	19	33	27	7	10	9
227/229	TIE LINE	117.0	140.1	157.6	10	10	11	2	2	3
229/232	TIE LINE	135.1	158.4	173.0	12	22	37	2	2	2
230/232	TIE LINE	183.8	225.8	256.0	5	27	76	1	1	1
233/345	TIE LINE	118.6	127.5	128.7	5	5	5	1	1	1
225/232	TIE LINE	102.1	114.3	118.4	6	11	14	2	2	2
225/229	TIE LINE	108.4	112.9	112.3	5	6	6	2	2	2
225/233	TIE LINE	< 100	100.6	105.5	0	1	1	0	1	1
340/345	TIE LINE	< 100	102.0	< 100	0	1	0	0	1	0
TOTAL					151	467	613	36	52	57

Table 12. Mitigating Load Shedding (MW) under Winter Scenarios

Power Flow Model Zones	Load Shedding (MW)		
	Scenario 9	Scenario 10	Scenario 11
201 AP	654	867	933
205 AEP	0	0	0
212 DEO&K	8	8	8
225 PJM	0	0	0
226 PENELEC	0	0	0
227 ME	28	31	33
229 PL	125	125	15
230 PECO	41	41	41
232 BGE	1103	1492	2697
233 PEPCO	0	0	679
235 DP&L	0	0	0
320 EKPC	379	367	288
345 DVP	1228	1778	2132
222 CE	0	0	0
228 JCPL	0	0	0
209 DAY	0	0	0
TOTAL	3,567	4,708	6,826

5 Observations and Discussions

- Under normal operating conditions and with generation resources secured with sufficient fuel for uninterrupted generation, the PJM system's resources meet the demand and maintain the electric grid's reliability (Scenario 1). Even so, adequate resources will challenge the PJM system in the future when the grid is under abnormal grid operating conditions, which will happen more often than previously.
- Transportation and building sector electrification and load increases due to emerging industry developments (e.g., hydrogen production and data centers) create fast load growth and electricity use never seen historically. Further, the regional electric demand is peaking less in summer and more in the winter, presenting a challenge in fueling the electric generation during peak demand hours. As shown by Scenarios 2, 5, 6, and 7, maintaining resources of sustained generation capability is imperative as the electric system adjusts to these new load demands during extreme weather events.
- Maintaining fuel diversity and understanding new energy resources' different seasonal operating attributes are important in maintaining grid reliability and resilience. PJM has recognized the differences via its installed capacity markets and accredited the different resources with seasonal accreditation values. Using these values, Scenario 2 has demonstrated a potential inadequate resource situation for winter 2028. One possible mitigation involves pairing long-duration storage with all newly planned solar PV in 2028. This strategy can help the system satisfy the LOLE standard (Scenario 3). However, this strategy needs to be supported by PJM's competitive market if it is economically attractive for all future solar projects to pair with long-duration storage. Additionally, it can be operationally challenging to manage the charging and discharging of an extremely large number of long-duration battery storages without negatively impacting transmission security.
- The electric grid is highly dependent upon the uninterrupted performance of the generation resources. Because the natural gas transportation system and the electric power grid were not originally designed to function as an integrated whole nor to the same reliability standards, failure in the natural gas delivery system presents a common mode of multiple outages of the natural gas-fueled generation stations. Such common mode outages could make the reliability 8.4 times worse, from a LOLE of 0.24 (Scenario 2) to 2.02 (Scenario 5) for winter 2028.
- The regional transmission upgrades can improve the integration of more renewable resources, reduce renewable curtailment, and provide the needed capacity and energy among various PJM zones. Scenario 4 illustrated that an increase of 50% in intrazonal transmission capacity adjacent to these zones can decrease the LOLE from 0.24 (Scenario 2) to 0.04. This mitigation will satisfy the 0.1 day per year criterion. However, expanding transmission capacity is very difficult, so a significant expansion of transmission is not considered feasible.
- The resource shortfall shown in Scenario 2 can worsen if an additional 5,000 MW of coal-fired generation is retired (Scenario 6). This situation cannot be mitigated by adding intermittent resources alone, as the grid is losing dispatchable generation resources of relatively high availability and predictability. The intermittent resources have much lower production per installed MW of capacity and cannot produce energy without sun or wind.
- The resource adequacy criterion violation with an additional 5,000 MW of coal-fired generation retired could not be mitigated by transmission expansion (Scenario 7). Maintaining a sufficiently diversified resource mix is essential and allows ample time for the changing dynamics to be understood as the future system evolves and new information becomes available. However, expanding transmission capacity is very difficult, so a significant expansion of transmission is not considered feasible.
- Dispatchable generation is essential for secure transmission system operations. When there is sufficient generation during the summer peak hours, the transmission system would have enough dispatchable

generation to help maintain secure transmission operation. The situation becomes very challenging during winter, particularly under severe winter weather conditions.

- The transmission system security analysis showed that in simulating the single and multiple contingencies for the summer 2028 under scenario 8, certain transmission system overloads were detected in facilities at voltage levels of 230 kV and above. The amount of equipment involved in overloads after contingencies increases from 30 (Scenario 8) to 32 after retiring the fossil generation from Scenario 8. These facilities could experience an overload of up to 55.2% following a contingency in the transmission system.
- In winter 2028, the system encountered a notable hurdle with the assumed retirements of coal and gas resources. The resultant resource balance is severely constrained, posing significant challenges in delivering energy to consumers while upholding security and reliability standards for the transmission systems. The predicament intensifies in Scenario 11, which assumes, in addition to the retirements in 2028, an additional 5 GW of coal retirements. In this scenario, 100% of coal generation resources and 97.5% of gas-fired generation plants must be used, leaving minimal leeway for dispatchable generation to participate in securing transmission operations.

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RELIABILITY MUST RUN AGREEMENTS
October 13, 2022

INTRODUCTION

Coal-fired and other thermal power plants provide attributes that are necessary to maintain a reliable electricity grid. However, half the existing coal fleet (more than 93,000 MW) has announced plans to retire by the end of 2030, with the likelihood of even more retirements due to EPA regulations. The premature retirement of unprecedented amounts of coal-fired generating capacity combined with the increasing penetration of renewable power sources, which do not provide certain reliability attributes, have prompted warnings about shortages of electric generating capacity and other potential reliability problems.

Reliability Must Run (RMR) Agreements have been used to keep power plants operating past their planned retirement dates in order to avoid reliability problems. This paper explains at a high level how RMR Agreements work. Because most of the coal fleet is located in four regions of the country, the paper focuses on the RMR process in each of those regions.

OVERVIEW

RMR Agreements, also referred to as System Support Resource (SSR) Agreements, are contracts negotiated between a regional transmission organization (RTO) or independent system operator (ISO) and an electricity generator that typically provide cost-based compensation in exchange for which the generator defers deactivation (retirement). (Throughout the rest of this paper, we refer to these collectively as "RTOs.") RMR Agreements are subject to approval by the Federal Energy Regulatory Commission (FERC). There is no standard RMR Agreement across regions, so this section of the paper is written in generalities.

Once it receives a notice of planned deactivation, the RTO conducts a study of the reliability impacts if the generator were to retire. If the study indicates an unacceptable reliability impact and no other substitute resources can serve the need in a timely manner, the RTO may ask the generator to defer its deactivation.

A generator may be willing to defer deactivation because RMR Agreements generally provide payments sufficient for the generator to recover its costs of operation, including costs to obtain or update components of the facility, and earn a return. Agreements typically are short term, with an initial term of no longer than one year, subject to extension, but often with reserved RTO rights to terminate the agreement with prior notice, such as 60 or 90 days, whenever the RTO unilaterally determines the reliability need has ended.

RMR Agreements often are necessary because of local transmission limitations that result in the need for a generator in a particular area. In other words, because of a transmission bottleneck, a generator from outside the area cannot substitute for the generator in the constrained location, leading to the need for a specific generator. When transmission upgrades or other changes that allow for improved power flows are placed in service, the RMR Agreement is no longer needed. In most cases, the generator is then expected to retire.

If the generator does not retire after the RMR Agreement is terminated, it may be obligated to return a portion of the financial support it received during the term of the Agreement. RMR Agreements also may severely restrict a generator's operations, which may be limited to emergency situations. RMR Agreements do not override compliance with environmental restrictions.

RMR Agreements are considered a last resort to be used only when there is no other cost-effective alternative. One reason RMR Agreements are disfavored is because RTO wholesale markets typically pay all generators in a specified region a single market clearing price based on the offer of the most expensive generator whose offer is accepted. When a high cost generator that otherwise would set the price leaves the market to be compensated under an Agreement, the price received by other generators is depressed. This can have a domino effect, leading other generators to require financial support to remain operational. While short-term use of RMR Agreements has been tolerated, out-of-market payments made to RMR generators are considered antithetical to wholesale competitive markets.

DRAWBACKS

Although RMR Agreements have been used in the past to avoid reliability problems, they have drawbacks, including the following:

- RMR Agreements are not meant to address resource adequacy problems and declining reserve margins caused by thermal retirements. Rather, RMR Agreements are meant to address temporary transmission security issues caused by a generator retirement. Agreements expire when transmission has been built to remedy the transmission security issue.
- There might not be sufficient financial incentive for a retiring generator to enter into an RMR Agreement, and a retiring generator typically cannot be forced to enter into an Agreement.
- RMR Agreements do not supersede environmental regulations, which could prevent a generator from continuing to operate or constrain its operations.
- A generator may be unable to secure sufficient fuel during the term of an RMR Agreement because of uncertainty over how much the plant will be called on to operate.
- RMR Agreements are typically contested, making resolution unpredictable and time consuming which is a disincentive for generators to pursue Agreements.
- Not all regions have an established process for defining the types of reliability problems that could or should be addressed by RMR Agreements.

AGREEMENTS BY REGION

- **PJM Interconnection, L.L.C.** The deactivation of generating units in the PJM region is governed by Part V of the PJM tariff. Generation owners must provide PJM with notice of their intention to deactivate a unit up to six months prior to the deactivation date. PJM will conduct studies quarterly to determine a need for units proposing to deactivate. The notice gives PJM the opportunity to study the transmission system to determine if any of the deactivation notices submitted in advance of the study period could affect system reliability and to develop a plan for transmission upgrades.

PJM will notify the generator owner within 60 days from the end of the quarter during which the deactivation request was submitted if a reliability issue has been identified. This notice will include the specific reliability impact resulting from the proposed deactivation, as well as an initial estimate of the time it will take to complete the necessary transmission upgrades.

Generation owners have an unconditional right to deactivate their facility after the advance notice period has passed. However, if PJM finds a need for a facility's continued operation, the generation owner may elect to continue to operate past the planned deactivation date in order to maintain system reliability pending the completion of transmission upgrades. Such generators can negotiate compensation with the PJM Market Monitoring Unit or make a filing with FERC to recover the entire cost of operating the unit beyond the proposed deactivation date. PJM does not maintain a standard RMR Agreement in its tariff. However, past Agreements may be used as a model.

RMR cost-of-service filings typically will be set for hearing by FERC, with the ability to pursue settlement talks before a hearing date is set. The market monitor, PJM, and the incumbent transmission provider are among the parties that frequently elect to participate in the settlement discussions. While the settlement talks typically will not delay payment based on the cost support proposed in the FERC filing, the generator will be subject to a refund obligation, with interest, if the ultimately approved payment amounts are less than the filing sums. Therefore, the generator faces uncertainty during an extended period of time until a settlement is reached or an order issues after a hearing.

- **Midcontinent Independent System Operator**   MISO uses SSR Agreements to provide cost-based compensation up to a unit's full cost of service. The current rules are detailed in Section 38.2.7 of the MISO tariff. However, MISO has announced plans to make a filing with FERC in November seeking to make certain changes. These tariff changes would not take effect until one full study period (approximately one calendar quarter) after the effective date of the tariff changes approved by FERC.

  An SSR Agreement may only be entered into after all potential alternatives have been determined inadequate. The standard term of such an Agreement is 12 months, with the possibility for extensions. The SSR Agreement process is triggered by a notice that a generator seeks to suspend operations. The current tariff provides that this notice must be provided to MISO at least 26 weeks prior to the planned retirement date. During this 26-week notice period, MISO will conduct a study to determine whether all or a portion of the resource's capacity is required to maintain system reliability, in which case the generator may be eligible for an SSR designation.

  MISO has concluded that the transition of the resource fleet to renewable energy resources and the timing of thermal retirements are driving a need for improvements to the tariff provisions involving SSR Agreements. As the resource fleet evolves, MISO has reached the conclusion that it needs to review elements of its SSR process to ensure reliability is maintained. In particular, MISO has proposed an extended advance notice period for units seeking to deactivate, quarterly study kickoffs, and additional stability studies.

Instead of the 26-week prior notice of a planned suspension of operations, MISO's proposed tariff changes would require notice at least four full Quarterly Study Periods before the proposed suspension date, which equates to at least 52 weeks prior to the suspension, double the current notice period. MISO will work with the relevant transmission owner to determine whether the transmission system might experience violations of NERC Reliability Standards or local planning standards if the generator is deactivated. This study does not consider possible effects on the transmission systems of neighboring balancing authorities.

While the current tariff provides that MISO will endeavor to respond to the generator within 75 days of the date of its notice as to whether a transmission system reliability issue has been identified, the proposed tariff changes would more than double the time MISO has to produce study results to 150 days after the next Quarterly Study Period starts. If MISO finds a reliability issue and cannot identify an alternative to the SSR Agreement, then MISO will enter into an SSR Agreement to keep the facility in operation so long as its operation is not inconsistent with a legal or regulatory obligation. MISO will expect the unit owner to make good faith efforts to minimize the costs of improvements that are needed by seeking available waivers or exemptions from environmental or other regulatory requirements.

MISO will engage with stakeholders to discuss alternatives to the SSR designation. MISO must pursue an alternative to the SSR designation if one is identified. In particular, it must determine whether the need for the retiring facility can be satisfied in a timely manner by new generation, generation redispatch, energy storage, system reconfiguration and changes to operation guidelines, demand response and load control, and/or transmission projects.

Once a generator provides a notice of planned suspension, it retains rights to rescind that notice. However, there are financial consequences that serve as a disincentive to submitting a retirement notice to explore whether the unit would be eligible for an SSR Agreement. For example, if a generator submits a notice, is determined not to be eligible for an SSR Agreement and elects not to retire, it will be held responsible for the costs of MISO's studies.

MISO must avoid dispatching an SSR unit on an uneconomic basis whenever possible. The SSR unit is, however, permitted to offer into the market when doing so would not interfere with its ability to provide SSR service to MISO. Net revenues received from operations will be deducted from the SSR payments. MISO's standard compensation for SSR service is limited to no more than the costs incurred for extended operation up to the fixed costs. A generator may make a filing with FERC to seek any additional compensation, including capital improvements to comply with environmental requirements.

MISO regularly reviews SSR designations and its transmission system to determine whether designations should continue. Typically, MISO can provide notice of termination of an SSR Agreement with as little as 60 days' notice, although notice of as little as 30 days has been negotiated in the past.

- **Southwest Power Pool** SPP does not have an established RMR or SSR process. Instead, it has a Generator Retirement Process, which is found in Attachment AB of its Tariff. The process sets out retirement notification procedures and allows SPP to evaluate the impacts of retiring generation on the SPP transmission system. A generator must provide notice to SPP one year prior to a proposed retirement date. SPP will then study the impact of the retirement with an initial screening within 30 calendar days and the possibility of more detailed studies based on those initial results.

  SPP's inclusion of the Generator Retirement Process in its Tariff is a relatively recent development. The addition was triggered by the increase in generator retirements on the SPP system in recent years, as well as SPP's belief that this trend will continue. SPP's Generator Retirement Process focuses solely on transmission solutions through network upgrades. Because SPP does not have an equivalent RMR tariff process or standard agreement for compensating generators as in other RTOs, generators would have to convince FERC that SPP's failure to offer them a cost-based contract leads to unjust, unreasonable, and unduly discriminatory terms of service. A generator would do this by initiating a FERC proceeding, which can be a costly and uncertain process. Because of SPP's lack of a process, it is unlikely that an Agreement could be employed to stave off a reliability problem.

- **Electric Reliability Council of Texas** The protocols for RMR service in ERCOT are set forth in Section 3.14 of the ERCOT Nodal Protocols. ERCOT is not generally subject to FERC jurisdiction but has a process that involves reporting to its Board and dispute resolution through the Public Utility Commission of Texas (PUCT).

  ERCOT may enter into an RMR Agreement with a retiring generator if ERCOT determines the resource is needed for voltage support, stability, or because of a local transmission constraint. Its protocols provide that it must limit the use of Agreements to the greatest extent possible. Unlike many other RTOs, a generator can voluntarily petition ERCOT for contracted RMR status. A generator cannot be forced to provide RMR service.

  The generator must submit a Notice of Suspension of Operations to trigger ERCOT's consideration of an RMR Agreement. The notice is to be provided at least 150 days prior to any requested suspension date of more than 180 days and must commit to closure, absent a finding of reliability need. ERCOT will publicly post the notice, and, unlike other regions, allow a public comment period of 21 days. ERCOT will conduct a study of alternatives to the RMR Agreement, which it will post publicly.

  Within 30 days of receiving the Notice of Suspension, ERCOT will issue a market notice as to whether the unit may need to continue operations. ERCOT is to complete its reliability studies within 60 days of the Notice of Suspension. Once it has reached a decision, ERCOT will publicly post notice of its determination of need for the generator. This will trigger the process of issuing a request for proposals to find an alternative to the generator. ERCOT will endeavor to set deadlines so that the process of identifying alternatives is completed within the 150-day period after the

Notice of Suspension was submitted. ERCOT will select the most cost-effective option between the RMR Agreement and other alternatives.

If ERCOT determines it needs the generator, the generator has 10 days to provide additional information to ERCOT, which should include an initial estimated budget of its Standby Cost and RMR fuel adder. Shortly thereafter, ERCOT and the generator will begin negotiations, even though an alternative may end up being more cost-effective. Should the 150-day notice period pass without a substantive determination of need by ERCOT, the generator may file a complaint with the PUCT. The ERCOT Board must approve ERCOT's execution of an RMR Agreement.

ERCOT may execute Agreements with an initial term that is at least one month in duration. Typically, the Agreement's term should not extend beyond one year. ERCOT may allow an exception to the one-year limit if the generator must make a significant capital expenditure to meet environmental requirements or to ensure availability. Even then, however, ERCOT will conduct an annual review and if that review indicates the resource is no longer needed, it will initiate exit negotiations. In fact, within 90 days of executing an Agreement, ERCOT must begin a private notification process to its Board of an exit strategy to the RMR Agreement by providing the Board with future cost-effective alternatives to its renewal. An Agreement may be extended for a subsequent term if the unit continues to be the most cost-effective solution.

QUESTIONS

Nationwide, more than 200 coal-fired generating units (totaling more than 93,000 MW) have announced plans to retire by 2030. However, this total does not include additional retirements that will result from future EPA regulations. Given the large number of expected coal retirements, the potential for reliability problems, and the drawbacks with RMR Agreements, there are at least four important questions that need to be considered by grid operators, generators, utility commissioners and policymakers:

1. *Are RMR Agreements an effective way to prevent a large number of coal retirements from causing both resource adequacy and reliability problems, or are there more effective ways?*

2. *Would grid operators need to change their RMR procedures in order to evaluate the resource adequacy and reliability impacts of a large number of coal retirements? How long would it take to make these procedural changes?*

3. *Would a large number of RMR Agreements be harmful to electricity markets? Are there other unfavorable consequences of a potentially large number of RMR Agreements?*

4. *Will EPA design its regulations to mitigate coal retirements and avoid increasing risks to reliability?*

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