December 20, 2023

The Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave, N.W.
Washington, DC 20460

Re: EPA's Supplemental Proposal on Clean Air Act Section 111 Rules for Power Plants. Docket No. EPA-HQ-OAR-2023-0072.

Dear Administrator Regan:

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's or Agency's) supplemental notice of proposed rulemaking (Supplemental Notice) for regulating greenhouse gas (GHG) emissions for the power sector under the Clean Air Act (CAA), *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 111 Rules). 88 *Fed. Reg.* 80,682 (Nov. 20, 2023). Notably, the Agency is seeking comment on "whether to include mechanisms to address potential reliability issues" with respect to EPA's Proposed 111 Rules. *Id*. Reliability mechanisms should be included in the Final 111 Rules. These should provide paths to compliance with GHG emissions limitations for units whose operations may be essential for the reliability of the energy grid. EEI's comments outline such paths.

EEI members are united in their commitment to get the energy they provide as clean as they can as fast as they can, while keeping reliability and affordability front and center, as always, for the customers and communities they serve. Across the nation, EEI members are leading a clean energy transformation, making significant progress to reduce GHG emissions, while also creating good-paying jobs and an equitable clean energy future.

EEI appreciates the opportunity to continue to actively and constructively engage with EPA on the agency's full suite of climate and environmental regulations for power plants. Please contact Alex Bond at abond@eei.org (202-508-5523) with any questions.

Sincerely,

Emily Sanford Fisher
Executive Vice President, Clean Energy
General Counsel & Corporate Secretary

COMMENTS FROM THE EDISON ELECTRIC INSTITUTE ON THE ENVIRONMENTAL PROTECTION AGENCY'S SUPPLEMENTAL NOTICE OF PROPOSED RULEMAKING ON 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

Docket No. EPA-HQ-OAR-2023-0072

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The Edison Electric Institute (EEI) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's or Agency's) supplemental notice of proposed rulemaking (Supplemental Notice) for regulating greenhouse gas (GHG) emissions for the power sector under the Clean Air Act (CAA), *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 111 Rules). 88 *Fed. Reg.* 80,682 (Nov. 20, 2023).[1] EPA's Supplemental Notice requests comment on an Initial Regulatory Flexibility Analysis following the completion of a Small Business Advocacy Review. Notably, the Agency is seeking comment on "whether to include mechanisms to address potential reliability issues" with respect to EPA's Proposed 111 Rules. *Id*.

[1] EEI filed extensive comments on to the Proposed 111 Rules in this Docket on August 8, 2023, in response to the proposal that was noticed in the *Federal Register* on May 23, 2023. *See* 88 *Fed. Reg*. 33,240. These comments in response to the Supplemental Notice should be read in conjunction with those comments.

EEI is the association that represents all U.S. investor-owned electric companies. EEI's member companies provide electricity for nearly 250 million Americans and operate in all 50 states and the District of Columbia. The electric power industry supports more than seven million jobs in communities across the United States. EEI's member companies invest more than $140 billion each year, on average, to make the energy grid smarter, cleaner, more dynamic, more flexible, and more secure; to diversify the nation's energy mix; and to integrate new technologies that benefit both customers and the environment.

I. Introduction and Executive Summary.

EEI's member companies are leading a profound, long-term transformation in how electricity is generated, transmitted, and used. This clean energy transition already has resulted in significant GHG emissions reductions, as EPA has recognized, and more than 40 percent of our nation's electricity now comes from clean, carbon-free sources. EEI's member companies are committed to getting the energy they provide as clean as they can as fast as they can, while keeping customer reliability and affordability front and center.

Across the industry, electric companies are investing in a broad range of carbon-free technologies and approaches, with the goal of demonstrating these technologies so that they can help further reduce power sector emissions when they satisfy industry performance requirements and are affordable for customers. Electric companies and EPA agree on the long-term clean energy vision for the sector that is embodied in the Proposed 111 Rules: electric companies have reduced and will continue to reduce GHG emissions and will use emerging technologies to reduce emissions from new and existing fossil-based generation.

Grid reliability is and will continue to be a top priority for EEI's member companies and their customers. The last few years have seen extreme summer and winter conditions that have challenged the reliability of the grid, raising concerns about the retirement of dispatchable, 24/7 generation, the speed with which new generating resources can be interconnected, the need to expand the capacity of the grid, the clean energy and energy infrastructure supply chain, and increased demand for electricity as a result of economic growth, domestic manufacturing, and electrification. Regardless of any final EPA regulations addressing GHG emissions from the new and existing fossil generating fleet, the clean energy transition is not going to be easy.

Challenges do not mean that this transition is impossible or that our larger goals for a resilient, equitable, affordable clean energy future should change. What these challenges do mean, however, is that we will need to work with and across a myriad of stakeholders to solve them, be prepared for progress to be bumpy on occasion, and be willing to be flexible. The investor-owned electric companies are committed to working with EPA, state regulators, the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), customers, environmental groups, and others to make the clean energy transition successful.

EPA need not address every potential reliability challenge associated with the clean energy transition via a mechanism included in the Final 111 Rules. Reliability tools and mechanisms should be included in the Final 111 Rules and should be focused on the particular challenges that arise from the structure of those Rules. In its simplest form, this means that EPA should provide paths to compliance with GHG emissions limitations for units whose operations may be essential

for the reliability of the energy grid. To accomplish this, EPA may need to provide more flexibility to amend state compliance plans to allow units to change compliance pathways more easily and efficiently. EPA also may need to create a process whereby grid reliability experts can provide input to EPA about potential challenges, in support of requests for compliance flexibility for reliability-critical units. However, potential reliability-related challenges unrelated to the structure of the Proposed 111 Rules can and should be addressed by other stakeholders and those charged with maintaining reliability.

As discussed in these comments in more detail, EPA also should finalize reliability tools and mechanism in conjunction with expanded compliance flexibilities for states and units that can help obviate the need to deploy reliability-specific mechanisms while supporting the ability of units to comply with EPA's final guidelines.

These comments also update EEI's August 2023 comments to note developments regarding the deployment of carbon capture and storage (CCS) and hydrogen technologies, and request that EPA seek additional data regarding the operations of the existing natural gas-based turbines to inform the development and finalization of standards for those units.

II. EEI's Member Companies Continue To Lead The Clean Energy Transition

EEI's member companies are leading a profound, long-term transformation in how electricity is generated, transmitted, and used. This transformation is being driven by a wide range of factors, including relatively lower prices for natural gas, particularly as compared to historic high prices; increased deployment of renewable energy resources, energy efficiency measures, and demand-side management; technological improvements; changing customer, investor, and owner

expectations; federal and state regulations and policies; legislation, including the Infrastructure Investment and Jobs Act[2] (IIJA) and Inflation Reduction Act of 2022[3] (IRA); and the increasing use of distributed energy resources. Across the industry, electric companies are investing in a broad range of affordable, carbon-free technologies and approaches with the goal of finding the most cost-effective ways to deliver resilient clean energy.

The mix of resources used to generate electricity in the United States has changed dramatically over the last decade and is increasingly clean.[4] In 2022, for the first time, renewable energy sources[5] surpassed coal as a generation resource: 22.6 percent of total generation at utility-scale facilities in the United States came from renewable sources compared to 19 percent from coal-based generation.[6] In total, more than 40 percent of America's electricity came from clean carbon-free resources in 2022, including nuclear energy, hydropower, solar, and wind,[7] putting

[2] Pub. L. No. 117-58.

[3] Pub. L. No. 117-169.

[4] *See* U.S. Energy Information Administration (EIA), Today in Energy: Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022 (Mar. 27, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55960&src=email; *See also* EIA, Electric Power Monthly: Data for February 2023—Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2013-February 2023 (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01.xlsx; *and* EIA, Electric Power Monthly: Data for February 2023—Table 1.1.A. Net Generation from Renewable Sources: Total (All Sectors) (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01_a.xlsx.

[5] Renewables here include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, hydroelectric conventional, solar thermal, photovoltaic energy, solar, and wind. *See* EIA, Electric Power Monthly, Table 1.1, *supra*, n.3.

[6] *See id*.

[7] *See id.*

clean resources at parity with natural gas generation, which provided approximately 40 percent of the country's total electricity generation in 2022.

As part of the move toward resilient clean energy, electric companies are deploying more energy storage, which is a key asset that helps integrate increasing amounts of renewables into the energy grid while also enhancing resilience and reliability. Electric companies are the largest users and operators of the approximately 32 gigawatts (GW) of operational storage in the country—representing 93 percent of active energy storage projects.[8]

Going forward, renewable and clean energy technology deployments will continue. EIA predicts that declining capital costs for solar panels, wind turbines, and battery storage, along with government support such as that provided through the IRA, will make these technologies increasingly cost-effective compared to the alternatives when building new power generating capacity.[9] EIA projects that renewable generation in the United States will more than triple by 2050, with both wind and solar responsible for most of the growth.[10]

[8] Compiled from the following proprietary sources: Wood Mackenzie Power & Renewables/American Clean Power Association, *U.S. Energy Storage Monitor* (2022); Dep't of Energy, *Energy Storage Database* (2022); Hitachi Energy, *The Velocity Suite Database* (2022).

[9] *See* EIA, Annual Energy Outlook 2023 (AEO 2023) 9 (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf.

[10] *See* AEO 2023—Table 16. Renewable Energy Generating Capacity and Generation: Electric Power Sector: Generation: Total (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=16-AEO2023&region=0-0&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.25-16-AEO2023~&ctype=linechart&sid=ref2023-d020623a.25-16-AEO2023~ref2023-d020623a.64-16-AEO2023&sourcekey=0.

The changes in the mix of resources used to generate electricity have profoundly decreased the sector's carbon dioxide (CO_2) emissions, the primary GHG emissions associated with electricity production. EIA's preliminary full-year estimates for 2022 find that electric power sector CO_2 emissions were 36 percent below 2005 levels, as low as they were almost 40 years ago.[11] These reductions will continue.[12] Further, 50 EEI member companies have announced voluntary, forward-looking carbon reductions goals, 41 of which include a net-zero by 2050 or earlier equivalent goal, and member companies routinely increase the ambition or speed of their goals or altogether transform them into net-zero goals to reflect changing expectations about the cost and availability of renewable generation and other clean energy resources.

In addition, the electric power industry has significantly reduced emissions of traditional air pollutants, such as mercury, HAPs, sulfur dioxide (SO_2), and nitrogen oxides (NOx). As of 2022, SO_2 and NOx emissions have declined 95 and 88 percent, respectively, since 1990.[13] In addition, mercury emissions have declined by 95 percent since 2010,[14] and total HAPs—including all acid gas emissions—declined by 96 percent between 2010 to 2017.[15] EEI's member companies see a clear path to continued emissions reductions over the next decade using current technologies,

[11] *See* EIA, Monthly Energy Review, Environment, Table 11.6—Electric Power Sector (Mar. 2023), https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

[12] *See* AEO 2023 at 4.

[13] *See* EPA, Power Plant Emissions Trends (Feb. 2023), https://www.epa.gov/power-sector/power-plant-emission-trends.

[14] *See* EPA, Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, page 2-7 (Dec. 2011), https://www.epa.gov/sites/default/files/2015-11/documents/matsriafinal.pdf.

[15] *See* 84 *Fed. Reg.* 2,670, 2,689 (Feb. 7, 2019).

including nuclear energy, natural gas-based generation, energy demand efficiency, energy storage, and deployment of new renewable energy—especially wind and solar[16]—as older coal-based and less-efficient natural gas-based generating units retire.[17] These technologies will continue to enable significant, cost-effective carbon reductions.

In the long term, reaching net-zero carbon emissions also will require the deployment of next-generation, carbon-free, 24/7, dispatchable technologies not currently available commercially. Supported by the clean energy tax incentives included in the IRA and the grant funding available via the IIJA, electric companies are partnering with technology developers, academic institutions, investors, philanthropists, each other, and other stakeholders to develop, demonstrate, and deploy these new clean energy technologies. These include long-duration energy storage, CCS, advanced nuclear and renewable generation, and clean fuels (like hydrogen, renewable natural gas, and ammonia). Developing and deploying a broad range of advanced clean energy technologies will further expedite the transition of the electric power sector to one that is low- or non-emitting while keeping electricity affordable and reliable for customers.

[16] Once built and when the resource is available, wind and solar are the least cost resources to operate to meet electricity demand because they have zero fuel costs. Over time, the combined investment and operating cost advantage increases the share of zero-carbon electricity generation. *See* AEO 2023 at 5.

[17] EIA notes that coal-based generation capacity will decline sharply by 2030 to about 50 percent of current levels (from about 200 GW to 100 GW) with a more gradual decline thereafter. *See* AEO 2023 at 13.

III. EPA Should Include Both Reliability-Specific Mechanisms And Additional Compliance Flexibilities In The Final Rules.

In the Supplemental Notice, EPA solicits comment on whether it should include "a specific mechanism or mechanisms to address grid reliability needs that may arise" as final CAA section 111 rules are implemented. *See* 88 *Fed. Reg.* at 80,684. Specifically, EPA seeks comment on:

- Tools and mechanisms already available to balancing authorities, RTOs, ISOs, and other reliability authorities to address reliability challenges;
- Circumstances and conditions that should be accounted for in a mechanism or mechanisms to address reliability concerns, including (i) concerns driven by events, such as extreme weather, unexpected generator outages, and unanticipated transmission line disruption; and (ii) concerns driven by supply chain or construction delays or disruptions for new generation, transmission lines, or other infrastructure as well as delays in permit issuance for controls required to meet the standards of performance;
- The technical form and structure of such a mechanism or mechanisms, such as an extension of the compliance date or a temporary, alternative standard of performance, and supporting details describing whether such a mechanism or mechanisms should be automated to enable extensions;
- Detailed descriptions of other reliability mechanisms or ways to address commenters' reliability concerns, including phase-in considerations for small entities;
- What information would be ample and appropriate, but not overly burdensome, to substantiate the need for and use of such a mechanism or mechanisms, including any appropriate documentation from balancing authorities, RTOs, or ISOs (the EPA specifically solicits comment on approaches that would minimize potential documentation burden); and,
- Lessons learned from the architecture of any previously proposed or finalized reliability mechanisms and the use of the mechanism in practice.

See id. at 80,684. EPA is correct to focus on specific mechanisms it can include in any final CAA section 111 rules to help address reliability considerations. When including such mechanisms in any final rules, EPA must specifically explain how such solutions fit within the Agency's legal and policy framework.

EPA need not address every potential reliability challenge via a mechanism included in the Final 111 Rules. As a general matter, EPA should take into consideration existing tools and efforts—as well as their benefits and limitations—when crafting a reliability mechanism. These existing tools are discussed, *infra,* in section C. Moreover, EPA's efforts to include reliability mechanisms should be focused on the particular challenges that arise from the structure of the Proposed 111 Rules. Other potential reliability-related challenges unrelated to the Proposed 111 Rules can and should be addressed by other stakeholders and those charged with maintaining reliability.

EPA's task is therefore to ensure that the Final 111 Rules themselves can be implemented without adverse impacts to reliability and do not complicate ongoing solutions as those the Proposed 111 Rules are finalized and states submit plans. This task is complex given that EPA's framework in the Proposed 111 Rules provides both opportunities and challenges from a reliability and compliance perspective—and that is before considering the inherent uncertainties about the various forms that compliance will take in future years. Importantly, EPA's subcategories for coal-based units will provide notable additional certainty for grid planners and others charged with maintaining the reliability of the grid because they will provide concrete information about the expected time horizons for when specific units are going to retire and no longer provide services to the grid. This will allow for future planning to replace those assets in an orderly fashion. However, at the same time, as units are placed into (or opt into, as the case may be) various subcategories, whether individual unit compliance decisions will create reliability challenges for the larger energy grid will become clearer. In that event, a change to the unit's status might be needed to address critical reliability considerations. Accordingly, it is essential that any reliability tools that EPA develops in the Final 111 Rules are flexible enough to address

future scenarios about which no one, including the Agency, FERC, the balancing authority, and the unit owner/operator, has sufficient clarity today. These tools, therefore, should be viewed as insurance policies for a changing grid.

In the development of such tools, EPA should be focused on compliance flexibility. The provision of additional compliance flexibility for states and units can help to limit the need for the use of any reliability mechanism, as well as the impact of extreme reliability events, by providing states and units with additional regulatory pathways and tools for compliance—as discussed *infra* in Section B. However, when reliability situations cannot be addressed via these tools, EPA must have a mechanism available to provide units with a pathway to comply with the section 111 rules and also run to meet system reliability obligations. As noted, EEI's members are committed to both reducing emissions and providing reliable and affordable power. Reliability mechanisms to address both acute and non-acute circumstances would provide unit owner/operators the chance to do both while ensuring they remain in compliance with their unit-specific obligations under EPA's 111 framework.

Ultimately, EPA must design a reliability mechanism that can be responsive to reliability considerations while providing a clear path for unit compliance, be adaptive to evolving scenarios, and be targeted to address specific reliability-based considerations that arise due to the section 111 framework and process. Suggestions and considerations for achieving these goals are discussed *infra* in Section A.

A. EPA Should Include a Reliability Mechanism Targeted at Critical Situations That Are Not Acute But Still Must Be Addressed Quicker Than the State Planning Process Contemplates.

EPA should develop and include a mechanism in the Final 111 Rules to allow for environmental compliance during situations when units must run to ensure system reliability, but which may not be acute emergency scenarios that more appropriately would be addressed via orders under Federal Power Act (FPA) section 202(c). Often, these types of scenarios revolve around the potential for resource adequacy shortfalls—e.g., delays in replacement generation or increases in demand over a multi-year basis that was unanticipated that result in a deficiency of resources to cover reliability obligations and necessary reserve margins—or a need for additional energy requirements to replace the energy provided by the retiring asset.[18] In these instances, the reliability challenges might require resources to increase their generation above forecasted levels or to delay a planned retirement until other assets (including transmission assets) are brought into service. These scenarios often are time limited but may extend beyond the 90-day window envisioned by FPA 202(c)—discussed more *infra*—to remedy supply chain constraints, permitting delays, and other roadblocks to deploying replacement or additional generation assets that could enable units to either retire or return to forecasted operational levels consistent environmental compliance obligations. These factors also often are outside the control of the unit owner or operator. Of further note, many of these scenarios are unpredictable by their very nature, and EPA will need to design a tool flexible enough to address a multitude of potential compliance-related scenarios that could arise.

[18] Many of these concerns were raised in the recent Technical Conference held by FERC on November 9, 2023. *See* https://www.ferc.gov/news-events/events/2023-annual-reliability-technical-conference-11092023.

Numerous EEI members have raised concerns about whether the Proposed 111 Rules are sufficiently flexible to address reliability concerns, based on real world examples. One example of this type of situation comes from EEI member Alliant Energy. Alliant announced in June 2022 that it would delay the retirement of its coal-based Edgewater Generating Station and Columbia Energy Center to 2025 and 2026, respectively, from their announced 2022-2023 retirement commitments, partially in response to additional requirements and reliability concerns raised by the Midcontinent Independent System Operator (MISO) regarding a potential energy shortage in the summer of 2023 and partially due to concerns regarding the lead time required to bring on over 1,100 megawatts of new solar generation in Wisconsin. Following the retirement of those assets, Alliant would have retired all of its coal-based assets in Wisconsin by the middle of 2026, consistent with the company's Clean Energy Blueprint.[19] As the company noted in its announcement, shifting the retirement dates for both coal-based units in Wisconsin helps ensure that the grid can weather multiple uncertainties while continuing to add cleaner, renewable energy to the grid in the MISO footprint. Notably the decision to delay the unit retirements consistent with the concerns raised by MISO occurred under a year before the scheduled retirement of the units.

Alliant was able to move these retirement dates to address reliability concerns without the use of FPA 202(c) because their retirement is voluntary, and delay did not implicate violations of any environmental or GHG emissions limits. But, once the Section 111 Rules are finalized, units subject to compliance requirements may not be able to change retirement dates in a timely fashion to respond to the changing needs of the energy grid unless EPA creates mechanisms to

[19] *See* https://www.alliantenergy.com/alliantenergynews/newscenter/23-generationupdate.

allow for revision to state plans in response to such concerns without unreasonable delay. As documented extensively in comments to EPA by states and other entities, the state plan process will take significant time. States not only need to enact needed policy, legislative, and regulatory changes, but they also need to engage in significant public participation and analysis before they can submit a plan to EPA. As currently proposed, a similarly intensive process would be required to alter any plan that has been approved by EPA.

EEI member PacifiCorp has had a similar experience. Two coal-based units at PacifiCorp's Naughton plant in Kemmerer, Wyoming recently shifted from a planned, but voluntary, retirement in 2025 to instead convert to utilizing natural in 2026. This change was based in part on the need to bolster reliability for PacifiCorp's system and the region. Under the Coal Combustion Residuals (CCR) rulemaking, both Naughton units are required to cease burning coal by December 31, 2025. As PacifiCorp evaluated how the planned retirement of the two units would impact reliable, dispatchable energy generation in the area and the region, it determined that converting the two Naughton units to natural gas was necessary and prudent to address considerable reliability challenges. Because the retirement of the two units was voluntary, PacifiCorp was able to shift from retirement to conversion to provide the much-needed, reliable energy generation resources while still meeting its commitment to cease burning coal.

Another example is the New York State Department of Environmental Conservation's (NYSDEC's) Part 227-3, Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple

Cycle and Regenerative Combustion Turbines, commonly known as the "Peaker Rule."[20] That rule, which is part of the EPA-approved state implementation plan (SIP) for New York State, authorizes the New York Independent System Operator (NYISO) to identify a unit as a "reliability source" if the unit is required to temporarily resolve a bulk power system reliability need, or a local transmission owner to do the same for a local reliability need. *See* 6 NYCRR § 227-3.6(a).[21] Once the NYISO or transmission owner has provided the NYSDEC with a unit's designation as a reliability source, that unit can operate outside of the applicable emissions limit until a permanent solution to the reliability need has been placed online or for up to two years. *Id.* at § 227-3.6(b). After this initial period, there can be an extension of the compliance deadline for up to another two years, if the reliability authority concludes that the reliability need still exists, the unit continues to address that need, and a permanent solution is in progress. *Id.* During this period, the unit's other NOx emissions limits (like under the NOx Reasonably Available Control Technology (RACT) program) continue to apply. Similar to Alliant's situation, NYISO or transmission owner can use the Peaker Rule's mechanisms to address their reliability concerns today, since they are not subject to an existing state plan under CAA section 111.

Other EEI members face a variety of other related reliability challenges, including but not limited to concerns regarding the amount of hydropower resources available to meet peak load; localized grid challenges due to load constraints and other geographic limitations; cross-border transmission and resource integration limitations and complications; lack of supportive infrastructure; and interconnection delays for new resources. These are all factors that can impact

[20] https://www.nyiso.com/documents/20142/39103148/NYC-Reliability-Solution-Fact-Sheet.pdf/169f336c-730f-6bd3-67c2-22037fcee56f?t=1700503745709.

[21] For incorporation into the New York State SIP, *see* 86 *Fed. Reg.* 43,956.

compliance for fossil-based units and necessitate alteration of the reduction pathways that may be included in state plans.

Further, the potential for delays is not limited exclusively to EGUs and retirement dates. Distribution transformers, which convert power to a useable voltage for use in homes and businesses, have become a bottleneck. Ongoing supply chain challenges and unprecedented demand for grid components has led to significant supply constraints on distribution transformers. Prior to the COVID-19 pandemic, lead time for distribution transformers—the time it takes to order and receive a new component—was less than one year on average. Today, due to complexities and inefficiencies in the supply chain, lead times exceed two years and are growing. Record demand for these products, the lack of available skilled labor to produce them, and challenges acquiring various components and materials which go in them are causing real-world problems: new building and housing construction projects have been stalled and utilities are unable to modernize the grid and help communities recover quickly from disasters. Further, lack of distribution transformers can delay necessary grid upgrades to incorporate additional clean energy in an efficient, effective, and timely manner. These challenges also may require revision to state plan approaches and deadlines.

But, it is not currently clear that such revisions to state plans will be possible or, if possible, sufficiently expedient. Concerns about the timing of state plan revisions are bolstered by the Agency's experience in the SIP process, as states often submit new SIPs and update existing SIPs to address the National Ambient Air Quality Standards (NAAQS). This process often takes several years, while states undertake their own administrative processes to update their plans,

and because EPA must undergo its own complex process to approve updates to state plans. These processes require significant resource commitment and time before plans are approved and enforceable so that affected entities can move forward with implementation.[22]

In the context of EPA's section 111 rules for the power sector, the time constraints inherent to the state plan process, therefore, can present a significant barrier to addressing reliability events within the context of EPA's proposed framework in a way that gives owner/operators of generation, grid operators, states, and regulators confidence that these scenarios can be effectively addressed. This is especially relevant given that—as described above—there exist scenarios that present reliability-based challenges that likely will have to be addressed outside the FPA 202(c) context but need to be addressed faster than the state plan revision process can capture given the time-consuming nature of that process.

To some extent, because these reliability issues largely will turn on the operation of existing units, EPA's focus in creating a reliability mechanism should be a focus on creating a workable and efficient state plan revision process. In the Alliant example, the relevant units likely would have needed to move from one retirement subcategory into a later subcategory. Their ultimate path to compliance—closure—would remain unchanged, but the exact timing of that closure would need to be updated in the state plan. And, consistent with reliability needs, moving between existing closure subcategories should not require extensive process. If a unit is moving between already-defined retirement subcategories and the owner/operator accepts the full

[22] As discussed *infra*, states can also include mechanisms in their own state plans absent a presumptively approved approach from EPA allowing units to shift between subcategories.

requirements of those subcategories, which can include, for example, capacity factor limitations or standards that reflect co-firing obligations, then the state plan should be able to be updated via notice to EPA and EPA should make clear that it will approve such updates without additional analysis or documentation requirements.[23]

As EPA examines how to make the state plan revision process more responsive these kinds of compliance changes, EPA should ensure that both unit owner/operators and states can initiate the revision process. As discussed *infra* in Section B, a key element of this approach will be to eliminate or suspend the proposed increments of progress requirements to allow for units to shift between subcategories more seamlessly and allow for continued operations to address reliability concerns as they arise.

Once EPA creates a plan revision mechanism that is streamlined and consistent with possible changing reliability needs, EPA will need a process to help the states and the Agency understand the potential reliability challenge that could warrant a change to state plans beyond simply moving between retirement subcategories and how best to address those concerns while also seeking to minimize emissions.[24] For example, these would be situations in which an existing

[23] If a unit could have opted into a later retirement subcategory at the time that the state plans were first developed, there should be no limitation on its ability to shift into that category in the future should circumstances warrant. Without such flexibility, all units rationally would choose the latest retirement subcategory to preserve operational flexibility. To incent retirements as early as practicable, EPA should allow changes between the defined subcategories without limitation. As discussed later, this will require EPA to eliminate or suspend the proposed increments of progress requirements. As discussed *supra* and *infra*, states can also enable this type of flexibility under their own authority under CAA section 111.

[24] As EPA establishes a reliability mechanism in the Final 111 Rules, EEI and its members are committed to working with states and the Agency to continue to resolve and address these issues;

natural gas-based turbine needs to exceed capacity factor limitations for some period of time, or a unit slated for closure needs to extend its retirement deadline beyond that provided by the latest retirement subcategory. Again, the goal is to provide units options to avoid having to operate such that they violate GHG emissions limits. EPA is not charged with solving the reliability challenge, but with providing a pathway to avoid compliance penalties for units that are needed to provide reliable power to customers.[25]

Here, EPA can build upon previous efforts to provide compliance pathways to units that need to operate beyond compliance deadlines. In the Mercury and Air Toxics (MATS) rulemaking under CAA section 112, EPA designed a reliability-specific process by which it would exercise enforcement discretion and provide a fifth year to units for compliance when reliability warranted such an extension of the compliance timeline.[26] There are valuable elements to the

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EPA should also make proactive efforts to continue this type of essential stakeholder outreach once it finalizes the rules.

[25] These proposed reliability approaches do not directly address the compliance challenges that could arise if new or existing units are attempting to deploy either CCS or hydrogen blending to comply but are not able to do so on EPA's proposed timelines because the necessary infrastructure is delayed, access to necessary inputs is constrained, or the technology is not performing consistently at compliance-levels. EPA will need to design processes to address these compliance challenges as well, even if they are not explicitly reliability related. In the final rules, EPA should address how it will exercise enforcement discretion or otherwise modify requirements, particularly for new units that are directly regulated by EPA, to address these kinds of compliance challenges.

[26] The 2011 Office of Enforcement and Compliance Assurance memo outlining this process is attached as Appendix A. The CAA section 112 context is different from the CAA section 111 context in ways that are relevant but should not prevent EPA from looking to the framework MATS compliance provides, since section 111 does not bind EPA to a statutorily mandated compliance timeline. Therefore, unit owners and operators need not rely on enforcement discretion to provide compliance timing flexibility to address reliability concerns, which gives EPA additional flexibility to rely on several of the process steps contained in the memo, if not the underlying legal rationale.

MATS approach that EPA should use here, particularly the documentation and administrative process needed to access any reliability mechanism.

Specifically, EPA should consider requiring unit owner/operators, states, or grid operators (RTO/ISOs or Balancing Authorities) to submit the following administrative steps to access any reliability mechanism, which are identified below and should be included in the Final 111 Rules as a presumptively approvable option for state plans:

- Written notice to a planning entity or planning authority—defined as a state air office, balancing authority, public utility commission and EPA Regional Office for regulated states and defined as a state air office, RTO/ISO and EPA Regional Office for states with wholesale power markets—within a reasonable period of time of learning of a potential reliability concern that might require relief under a reliability mechanism due to a variety of factors, including but not limited to lack of timely replacement generation, supply chain considerations outside of the unit operators control, lack of supporting transmission or other required energy infrastructure;

- Documentation, including appropriate supporting analysis or modeling, of the reliability risk if the unit or units were not in operation, which demonstrates that the unit or units are critical to maintaining reliability, that the scenario was not predicted with a high degree of certainty at the time of a final plan submission and that without relief the unit or units would (1) result in the violation of at least one of the reliability criteria required to be filed with FERC, or (2) cause reserves to fall below the required system reserve margin;

- Written concurrence with that analysis by the planning entity or planning authority for the area where the unit or units are located, where practicable;

- Copies of any written comments from third parties directed to, and received by, the unit owner/operator or planning authority in favor of, or opposed to, accessing the reliability mechanism for the unit or units;

- Quarterly updates to the planning entity or planning authority, EPA and all interested parties regarding whether the underlying reliability issue can be resolved through the use of the reliability mechanism, or whether a plan revision may be required; and,

- Consistent with the CAA's RULOF provisions, a proposal for operational limits and/or work practices to minimize or mitigate any emissions to the extent practicable during any operation not in full compliance with the 111 rules, when applicable and not resolved by the reliability mechanism and any available compliance flexibilities.

In adopting this framework for the Final 111 Rules, EPA should also note that it intends to, when appropriate, consult with FERC and/or other entities with relevant reliability expertise as part of any review of the use of such a reliability mechanism.[27]

Regarding potential relief offered under the reliability mechanism, EPA should tailor such relief based on the situation and by the type of unit—coal- or natural gas-based. For example, and as appropriate:

- For coal-based units that are part of a retirement-based subcategory, the reliability mechanism could extend the retirement date of a specific unit or units to address critical reliability needs to the end of the immediately preceding subcategory, or for a period not to extend past a set number of years;

- For coal-based units that are not part of a retirement-based subcategory, an extension of compliance until a unit can be projected to install the necessary control technology, including consideration of potential future capacity factor restrictions for an equivalent number of years on a situationally specific basis if appropriate and potentially to be addressed in a future plan revision;

- For gas-steam units, a one-year grace period to achieve the emissions rate of the higher subcategory, where applicable;

- For natural gas-based turbines, an up-to-three-year lifting or raising of the capacity factor requirements above the finalized threshold that would make any existing source gas rule applicable to those units, including consideration of potential future capacity factor restrictions for an equivalent number of years on a situationally specific basis and potentially to be addressed in a future plan revision;

- For natural gas-based turbines, an extension of an averaging period of up to one or three years, whichever is required, to allow for the unit to average more appropriately and manage reliability-based energy requirements; and,

- For new, base load natural gas-based turbines, an extension of compliance until a unit can be projected to install the necessary control technology, including consideration

[27] The involvement of FERC and/or other entities as part of this process ensures that a unit or units that are participating in any reliability mechanism or specific relief are properly scrutinized and that EPA is consulting with parties that have the appropriate reliability expertise.

of potential future capacity factor restrictions for an equivalent number of years on a situationally specific basis and potentially to be addressed in a future plan revision.

EPA should include a mechanism that has these types of relief available, and it should be included as a presumptively approvable option for states to include in plans. Such an approach would provide unit owner/operators, states and reliability entities with additional confidence that both compliance with EPA's final rule and system reliability can be addressed and maintained.

B. EPA Should Provide a Reliability Mechanism Along with Additional Compliance Flexibilities—Rather Than in Lieu of Those Flexibilities.

As noted in EEI's August 2023 comments, EPA must design final standards for all regulated units that allow for compliance. Key design elements that EPA incorporated into the Proposed 111 Rules—which include the use of subcategories and significant compliance flexibility for states and units—should be finalized consistent with the technical, legal, and policy recommendations set forth in these comments and those filed by EEI in August 2023.

EPA also should consider expanding the proposed design and compliance flexibilities and making other important changes to the proposed standards to support compliance. Final 111 Rules should:

- Set achievable, efficiency-based standards for new natural gas-based units, consistent with EEI's February 2023 recommendation to the Agency that these units be "capable" of future retrofit to install CCS or blend hydrogen when those technologies are demonstrated and available at costs that are affordable for customers;

- Allow states to recognize changes to how existing units will be operated in the future and the emissions benefits of retiring existing units through appropriate subcategories—for both existing coal- and natural gas-based EGUs;

- Affirmatively allow states to adopt mass-based compliance approaches for both new and existing units;

- Provide states with additional flexibility on the timing for state plan development and submittal to EPA, including the streamlining or elimination and suspension of increments of progress that can limit unit operational flexibility;

- Allow states to develop other decarbonization reduction pathways in their state specific plans, taking into account how each state is unique in electricity demand, short-term load growth, long-term load growth and at what pace, and many states have already developed prescribed approaches to address these issues; and,

- Provide units with dual-pathway approaches to state plan compliance, which recognize that planning for new technologies during the short window for state plan development will be challenging, provide a less prescriptive approach to the increments of progress to support these more flexible approaches, and allow for other innovative GGH emissions reduction approaches.

These key program design elements and compliance flexibilities, along with the others discussed in these comments, will enable states and electric companies to implement final standards that are achievable, reliable, and affordable.

Crucially, additional flexibility in compliance will enable units to account more for electric reliability considerations and, in practice, likely limit the need for states and units to utilize the Final 111 Rules' specific reliability mechanisms themselves. EPA should therefore ensure that it finalizes approaches that authorize states to explore additional compliance flexibilities in conjunction with any reliability-specific mechanisms. As a result, EPA must offer both additional flexibilities *and* a reliability specific mechanism to support states and unit owner/operators while providing for reliable electric service and environmental certainty.

C. Some Near-Term and Urgent Reliability Considerations Can Be Addressed by Existing Tools and EPA's Own Proposed Regulations, With Appropriate Modifications.

There are also other tools available to EPA and other Agencies. Some urgent and immediate reliability concerns can be addressed under section 202(c) of the Federal Power Act (FPA). FPA section 202(c) authorizes the Department of Energy (DOE or Department) to "require by order"

the "temporary connection of facilities, generation, delivery, interchange, or transmission of electricity" in the event of a war in which the U.S. is engaged or "when an emergency exists by reason of sudden increase in the demand for electric energy, or a shortage of electric energy, or of facilities for the generation or transmission of electric energy…or other causes." 16 U.S.C § 824a(c)(1).[28] In general, an order pursuant to FPA 202(c) can be issued by the Secretary for up to 90 days. Under the FAST Act amendments, the Secretary need not consult with EPA before issuing this first order. However, for any subsequent orders (up to two additional 90-day periods are permitted), DOE must consult with EPA or the relevant environmental regulator and include any limitations that regulator deems necessary to minimize violations of environmental standards. *See* 16 U.S.C. § 824a(c)(4). In practice, DOE has responded to initial requests for 202(c) orders expeditiously, often in a matter of days or, in extreme emergency conditions, hours.[29] Given this precedent and the intent of 202(c), this mechanism is clearly understood to apply to acute reliability challenges, and is used during specific, discrete, and urgent to emergent scenarios. This is demonstrated by the limited use of 202(c) orders—less than 20 times over the past 23 years, sometimes with orders addressing follow on and/or related reliability events. Those instances are documented on DOE's website.

[28] This authority was retained by the Secretary of Energy and not transferred to the Federal Power Commission—the precursor to the Federal Energy Regulatory Commission (FERC) — when it was created. In 2015, the FAST Act amended section 202(c) to provide limited relief from environmental liabilities incurred by entities when complying with an order from the Secretary under this section. *See* 16 U.S.C. § 824a(c)(3) and (4). An order under section 202(c) can be issued to any owner or operator of facilities used to generate, transmit, or distribute electricity. This owner or operator can be a public or private entity. *See* 10 C.F.R. § 205.370. The definition of an "emergency" first focuses on an "*unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown of facilities for the generation, transmission or distribution of electric power" and finds that "such events can be the result of weather, act of God, or other *unforeseen* occurrences not reasonable within the power of the affected entity to prevent…" 10 C.F.R § 205.371 (emphasis added).

[29] *See* ERCOT 202(c) order, February 14, 2021.

The benefit of 202(c) orders is that they permit units that are reliability critical to run, even if such operations may conflict with environmental regulations. These orders, therefore, are useful to address grid emergencies, but are definitionally (and appropriately) limited in terms of scope and duration. Nevertheless, 202(c) orders are one tool to address reliability concerns in certain scenarios, and to ensure that units that may need to run to address these concerns are able to do so.

Section 202(c) is not the only available tool to address environmental compliance during urgent and emergent reliability situations. EPA has also 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* 88 *Fed. Reg.* at 33,333.

The current regulatory definition of system emergency is any "abnormal system condition" that the RTO/ISO or control area administrator determines requires immediate automatic or manual

action to "prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system" and therefore calls for maximum generation resources to operate in the affected area or for the specific affected EGU to operate to avert loss of load. The emissions from units that are called on during these "abnormal system condition" would not count towards the compliance calculation for any individual unit. 88 *Fed. Reg*. 33,333-34.

As noted in EEI's August 2023 comments to the Agency, EPA should include this provision in the final rules and provide additional specificity as to what constitutes an "abnormal system condition." There are existing levels of energy emergency alerts (EEAs) as defined by the North American Electric Reliability Corporation (NERC) that are issued when grid operating conditions require available resources to generate at maximum levels to address system reliability. There are three separate EEA levels—1, 2 and 3—which are arranged in ascending order of emergency and need, with EEA 1 being issued when an area foresees or experiences conditions where all available resources are already committed, up to EEA 3 being issued when an area foresees (or has implemented) firm load obligation interruption. Reliability entities respond to EEA levels with increasing levels of generation requirements and emergency measures, as well.

EPA should consider using *at least* an EEA level 2, which is when an RTO/ISO or local balancing authority requests emergency energy from all resources and has activated its emergency demand response program.[30] During an EEA level 2, consumers are urged to

[30] EPA should also consider whether using EEA level 1 as the trigger for this provision given that these alerts are called by grid operators for functionally the same types of issues as higher alert levels.

conserve energy to help preserve grid reliability, and these events are intended to provide for unit operations that work to avoid serious reliability events. This level precedes alert level 3, which occurs when a grid operator is unable to meet minimum reliability reserve requirements and then rotating power outages begin occurring to preserve grid reliability broadly. All units operating when an emergency alert level 2 is declared are working to prevent the abnormal system condition included in EPA's definition, and EPA should confirm that those emissions should not negatively impact a unit's compliance. EEA level 2 events are usually in response to discreet events—e.g., a cold snap, hurricane, extreme heat, or storm event, or malfunction or other failure—and thus emissions associated with those events are likely to be both a) time limited and b) have the potential to meaningfully impact compliance for the affected units.

Further, since emergency alert levels impact the entire grid, EPA should use this definition for all coal- and natural gas-based units that may be required to run to avoid loss of load or other reliability events; when a grid operator or balancing authority calls on units under an emergency alert level 2, it calls on those units necessary to maintain reliability, regardless of fuel type, location, or other factors; as a result, EPA should ensure that all types of units, not just Subpart TTTT or Subpart TTTTa units, have the ability to access this provision in the regulations. Such an approach would help allow units and system operators additional certainty in responding to any reliability events or issues. EPA should finalize such an approach to help address urgent reliability scenarios within the framework of EPA's proposed 111 rules.

D. EPA Should Ground the Creation of Any Reliability Mechanisms in the Agency's Remaining Useful Life And Other Factors (RULOF) Statutory Authority.

CAA section 111(d)(1)(B) allows the Administrator to take into consideration, "among other factors, the remaining useful life of the existing source to which any standard applies." EPA

should note that the utilization of any reliability-specific mechanism would be squarely authorized given the language in section 111(d)(1)(B). Many of the units that could or would take advantage of such a provision would already be part of the subcategories that EPA has already designed to take into account the remaining useful life of sources that are in each subcategory—which is sensible since to be eligible for the imminent-, near- or medium-term subcategory, a unit must have an enforceable shutdown commitment, and would have a standard different from the one applied to long-term units. Further, the RULOF language in the statute exists and states may avail themselves of it regardless of whether a unit is part of an EPA-identified subcategory, and EPA should note that this authority is reserved for the states and also allows state plans to include reliability specific mechanisms independently of any EPA-approved approach. This language squarely authorizes EPA to set an alternative standard for these types of units if needed—and reliability considerations squarely fall in the "other factors" language in section 111(d)(1(B).

This approach would also 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." 88 *Fed. Reg.* 80,480 (Nov. 17, 2023). Importantly, this compliance flexibility also reflects the "core principle of cooperative federalism" embedded in the CAA. *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"). Further, given the D.C. Circuit's decision in *American Lung Association* noting that EPA could offer significant compliance flexibility to states and units and was not required to have sources implement the specific BSER prescribed by EPA, the Agency is well within its

statutory authority to offer a reliability-specific provision to states and units in any final rule. 985 F.3d at 942-43, 963.

The Agency should also note that it is relying on the RULOF authority inherent in the statute for this reliability mechanism while also working to finalize an expanded version of the RULOF provisions it put forward in the Proposed 111 Rules, consistent with EEI's August, 2023 comments. This is essential since the RULOF justification for the reliability mechanism would operate once a state has an approved plan, and the RULOF authority is also clearly useful, as EPA noted in its proposal, for states to consider as they work to develop their state plans before submitting them to EPA for approval. EPA should also work to ensure that this mechanism also works in conjunction with the other rulemakings it is finalizing as part of the holistic approach to power sector regulation, consistent with this legal authority to be flexible and the Agency's desire for coordinated decision-making.

IV. EPA Should Also Take Notice of Additional Technical Developments For The Rulemaking Record.

It is imperative that EPA design final standards for all regulated units that allow for compliance, since standards that allow for units to comply also help to address reliability considerations. Several recent developments that have occurred since EEI's August 2023 comments regarding EPA's proposed determinations that CCS and "low-GHG hydrogen" are the best system of emissions reduction are worth the Agency's note. As discussed below, these developments include (1) permitting-related and other delays or cancelations of proposed CO_2 pipeline projects and delay of an important federal program; (2) institution of an EPA Inspector General evaluation into the efficacy of the EPA Class VI well program for injection and storage of carbon dioxide in geologic formation; and (3) DOE's selection of the Regional Clean Hydrogen Hubs.

These developments support the contention in the August 2023 comments that neither technology is adequately demonstrated under the CAA and that EPA's proposed timing fails to account for the significant regulatory and infrastructure developments needed for both CCS and low-GHG hydrogen systems to support achievability throughout the electric sector of standards based on these technologies. In addition, the Energy Futures Initiative Foundation recently released a report analyzing the infrastructure that would be required to support the Proposed 111 Rules, which concludes that the need for major infrastructure deployments in the next decade could limit implementation.[31]

A. Recent Project Cancelations and Delays, Along with Challenges to the Federal Permitting Regime, Highlight Challenges with EPA's Assumptions About the Timing and Availability of Critical CO_2 Infrastructure in Support of the Proposed 111 Standards.

EEI and its members are working to develop, deploy and demonstrate CCS projects, since CCS, although location dependent, remains an essential emerging technology to address emissions throughout the power sector. CO_2 transportation from the point of capture to storage facilities or

[31] Energy Futures Initiative Foundation, *How Much, How Fast? Infrastructure Requirements of EPA's Proposed Clean Power Plant Rules* (Oct. 2023), https://efifoundation.org/foundation-reports/how-much-how-fast-infrastructure-requirements-of-epas-proposed-power-plant-rules/. For example, the report finds that "[w]ith 90% capture rates set by EPA's proposal, there would be 150 MTPA of captured CO_2 in 2035 and roughly 170 MTPA by 2042." *Id.* at 42. Importantly, "[d]eveloping and permitting enough CO_2 pipelines and geologic storage capacity to support EPA's proposal likely requires new policies and regulations that align the capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements. Permitting CCS projects is a highly uncertain process that can take years in ideal conditions [ ]. The CCS value chain covers multiple sectors—each with different regulatory systems with little federal coordination—creating complex permitting needs." *Id.* at 45. Further, "[l]arge amounts of dedicated renewables (115 GW in 2035, 850 GW by 2042) are needed to power electrolyzers (capacities of 37 GW in 2035, 275 GW in 2042) for clean hydrogen production [ ]. To put this into context, there is about 230 GW of wind and solar capacity on the grid today." *Id.* at 50. In addition, "more than 11,000 miles of new hydrogen pipelines (transmission and distribution) and more than 5,000 compressed hydrogen storage sites (50 tons capacity each) will be needed by 2035." *Id.* at 6.

markets for end-use is an integral component of the CCS system that would be needed to support electric sector use of CCS while preserving reliability and affordability. In the Proposed 111 Rules, EPA lists a number of CO_2 pipelines that have been announced, noting that they are "likely to be developed" and have been in the planning stage for several years. *See* 88 *Fed. Reg.* at 33,366. However, as EEI noted in its August comments and as experience since then has proven, "likely to be developed" does not mean "has been, or will be, developed," and does not provide assurances to EGU owners and operators that there will be CO_2 transportation available to ensure compliance with the proposed standards.

In fact, since EEI filed its comments on the Proposed 111 Rules in August of 2023, one of the CO_2 pipelines that EPA cites as support for its arguments has been postponed, another has moved to withdraw its application and plans to refile in 2024, and a third has been cancelled entirely. Together, these three projects—the Midwest Carbon Express CO_2 Pipeline Project, the Mt. Simon Hub, and the Heartland Greenway Project—would have spanned six states, represented approximately 3,650 miles of new dedicated CO_2 pipeline, and accounted for an over 68 percent increase in U.S. CO_2 pipeline infrastructure. *See* 88 *Fed. Reg.* at 33,293-94. These three projects also account for approximately 94 percent of the miles of the planned or announced new CO_2 pipeline that EPA notes in its GHG Mitigation Measures for Steam EGUs Technical Support Document, included in and used to support the Proposed 111 Rules.

Notably, developers of these projects have cited permitting challenges as the rationale for their decisions to delay, withdraw, or cancel. Recent trends underscore that this critical component of a CCS system will continue to face strong opposition from across the political spectrum and from

a range of stakeholders.[32] Given these concerns, the availability of necessary infrastructure on the timeline that the Proposed 111 Rules would require remains a concern.[33]

1. The Midwest Carbon Express CO_2 Pipeline Project Has Been Denied Necessary Permits.

The Midwest Carbon Express CO_2 Pipeline Project is an approximately 2,067-mile proposed project that would cross North Dakota, South Dakota, Nebraska, Minnesota, and Iowa. In the Proposed 111 Rules, EPA stated that this project planned a 2024 in-service date. However, based on recent statements, the project has delayed its in-service date until 2026.[34] This project has faced significant permitting challenges. On August 4, 2023, the North Dakota Public Service Commission (NDPSC) denied the project's October 27, 2022, permit application for the

[32] Soraghan, M., *CO_2 pipelines: The new populist Republican target*, EnergyWire (Sept. 21, 2023), https://www.eenews.net/articles/co2-pipelines-the-new-populist-republican-target/ (noting "[p]roject developers have suffered notable losses lately in the Republican states at the core of the carbon capture push," while "[m]uch of the groundwork for the opposition … has been laid by liberal groups. . . [t]hey've been joined by many conservative landowners made wary by past pipeline projects . . . and infuriated that the pipelines will cut across their farms and ranches.").

[33] It is worth noting that release of a DOE funding opportunity announcement (FOA), expected Q4 2023, has been delayed for the Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA) Program: Future Growth Grants under the Infrastructure Investment and Jobs Act (IIJA). U.S. Dep't of Energy, Notice of Intent: Bipartisan Infrastructure Law - Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA) Program: Future Growth Grants (Section 40304) (Aug. 25, 2023), https://www.fedconnect.net/FedConnect/default.aspx?ReturnUrl=%2Ffedconnect%3Fdoc%3DDE-FOA-0003079%26agency%3DDOE&doc=DE-FOA-0003079&agency=DOE. In addition, this $2.1 billion program is intended to support shared infrastructure projects, including pipelines, rail transport, ships and barges, and ground shipping, that connect anthropogenic sources of CO_2 with endpoints for its storage or utilization. DOE has issued a notice of intent indicating that it now anticipates the FOA will be released in Q1 2024.

[34] *See, e.g.*, Tomich, J., *Developer scuttles plans for Midwest CO2 pipeline*, GreenWire (Oct. 20, 2023), https://www.eenews.net/articles/developer-scuttles-plans-for-midwest-co2-pipeline/.

approximately 320 miles of pipeline that would be sited in North Dakota.[35] The project filed a request for rehearing with the NDPSC on September 7, 2023, noting changes to its proposed route to address concerns that intervenors had raised and providing additional studies, clarifications, and information. In response, the NDPSC plans to hold a hearing to allow the project the opportunity to demonstrate that it has cured the deficiencies identified in the August 4 order.

On September 11, 2023, the South Dakota Public Service Commission (SDPSC) denied the project's February 7, 2022, certificate application for the approximately 495 miles of the project that would be sited in that state. On October 13, 2023, the SDPSC closed the Midwest Carbon Express project's docket. The project has noted its intent to refine its proposal and reapply for a permit, though the timing of that reapplication and the duration of the resulting permitting process remain unclear.

With respect to the remaining states, the project's applications for the approximately 28 miles of pipeline that would be sited in Minnesota[36] and for the approximately 687 miles that would be sited in Iowa[37] remain pending as of the date of these supplemental comments. In Nebraska,

[35] SCS Carbon Transport LLC, *Findings of Fact, Conclusions of Law, and Order*, NDPSC Dkt. No. PU-22-391 (Aug. 4, 2023).

[36] Summit Carbon Solutions, LLC, *Route Permit Application for the Summit Carbon Solutions Otter Tail to Wilkin Project in Wilkin and Otter Tail Counties, Minnesota*, MNPUC Dkt. 22-422 (Sept. 12, 2022).

[37] Summit Carbon Solutions, LLC, *Petition for Hazardous Liquid Pipeline Permit*, IUB Dkt. HLP-2021-0001 (Jan. 28, 2022).

there is no state level agency with primary jurisdiction over CO_2 pipeline permitting—as a result, permitting decisions are left to individual counties. As of its last report, the project has secured easement agreements for more than 50 percent of the pipeline route in Nebraska, though it is unclear what the ultimate outcome for the Nebraska portion of the project will be.

2. The Mt. Simon Hub Has No Clear Path to Obtain Necessary Permits Without Improvements to the Federal Safety Regime for CO_2 Pipelines.

In the Proposed 111 Rules, EPA included the Mt. Simon Hub among the "number of CO_2 pipeline projects in the United States that are likely to be developed to meet growing demand for CO_2 and increased interest in CO_2 utilization and sequestration." GHG Mitigation Measures for Steam EGUs Technical Support Document at 28-29. This 280-mile project would include facilities in Illinois and Iowa. On November 20, 2023, the project announced[38] that it filed to withdraw its certificate application pending before the Illinois Commerce Commission (ICC) for the 166 miles of CO_2 pipeline that would be cited in Illinois, including 33 above ground facilities.[39] This withdrawal followed testimony from ICC staff indicating their intent to recommend that the ICC deny the project's application. The withdrawal and resubmission of its application in Illinois likely will impact the projects anticipated late 2025 in-service date.

Importantly, while an ICC Gas Engineer in the Energy Engineering Program of the Safety & Reliability Division agreed that the project developer is "fit, willing, and able to construct and operate" the project, he further explained that "it is my opinion that the current construction

[38] Press Release, Wolf Carbon Solutions U.S. to Refile Mt. Simon Hub Permit Application in Illinois in Early 2024 (Nov. 20, 2023), https://wolfcarbonsolutions.com/wp-content/uploads/2023/11/WOLF_MediaStatement_11_20_2023.pdf.

[39] Wolf Carbon Solutions US LLC, Application for Certificate Authority, ICC Dkt. No. 23-0475, at 3 (June 16, 2023), https://www.icc.illinois.gov/docket/P2023-0475/documents/339033.

guidelines for CO_2 pipelines do not adequately address public safety and new [Pipeline and Hazardous Materials Safety Administration or] PHMSA regulations may render the proposed route non-compliant."[40] Consequently, regardless of the outcome for the Mt. Simon Hub, CO_2 pipeline projects may continue to face significant regulatory hurdles beyond their control as state regulators with siting authority question the sufficiency of current PHMSA regulations and as PHMSA continues its efforts to update its regulations. On that point, PHMSA announced in 2022 that it would initiate a rulemaking to update its CO_2 pipeline safety regulations. PHMSA plans to publish a Notice of Proposed Rulemaking in June 2024, but has not set a date for a final rule.[41] The delay in this rulemaking likely will have a continuing impact on the timeline for the permitting and construction of CO_2 pipelines.

3. The Heartland Greenway Project Has Been Canceled.

The Proposed 111 Rules also cite the Heartland Greenway pipeline project, an approximately 1,300-mile CO_2 pipeline that would have spanned South Dakota, Nebraska, Minnesota, Iowa, and Illinois and carried carbon dioxide emissions from more than 20 industrial plants. Earlier this year, the SDPSC denied the project's certificate application and the project faced significant opposition and challenges before the Iowa Utilities Board as well. On October 20, 2023, the company issued a press release explaining that "[g]iven the unpredictable nature of the

[40] Direct Testimony of Brett Seagle, ICC Dkt. No. 23-0475, lines 292-94 (Oct. 24, 2023), https://www.icc.illinois.gov/docket/P2023-0475/documents/343441.

[41] *See* Congressional Research Service, Insight: Carbon Dioxide (CO_2) Pipeline Development: Federal Initiatives, IN12169 (Jan. 2, 2023), https://crsreports.congress.gov/product/pdf/IN/IN12169#:~:text=In%20response%20to%20these%20criticisms,date%20for%20a%20final%20rule.

regulatory and government processes involved, particularly in South Dakota and Iowa, the Company has decided to cancel its pipeline project."[42]

As noted, these three projects represent a significant portion of proposed CO_2 pipeline infrastructure. Their delay and cancellation, respectively, as a result of permitting challenges cast further doubt on the timing and extent of the CO_2 pipeline infrastructure that is a necessary component of the CCS system used as BSER in the Proposed 111 Rules. In addition, these examples demonstrate that EPA's assumptions about the timing of the development and deployment of CO_2 infrastructure are not grounded in the record or the experience of actual pipeline projects. At minimum, EPA has significantly underestimated the siting and permitting challenges that these projects have and will face.

B. EPA's Inspector General is Evaluating the Class VI Well Permitting Process; It is Not Clear How This Will Impact Permitting for CO_2 Storage.

On November 15, 2023, EPA's Office of the Inspector General sent a letter to EPA's Office of Water explaining that it plans to evaluate the Agency's Underground Injection Control Class VI Well Program for CO_2 injection.[43] The objective is to "determine whether the EPA has used available resources, including funding appropriated by the Infrastructure Investment and Jobs Act, to improve permitting of Class VI wells under its Underground Injection Control Program . . . [and] to identify how the EPA either has used or plans to use $5 million in annual Infrastructure

[42] Press Release, Navigator CO_2, Heartland Greenway Project Update (Oct. 20, 2023), https://navigatorco2.com/press-releases/heartland-greenway-project-update.

[43] U.S. Envt'l Protection Agency, Letter from EPA Inspector General to EPA Office of Water (Nov. 15, 2023), https://www.epaoig.gov/sites/default/files/document/2023-11/notification_memo_uic_class_vi.pdf.

Investment and Jobs Act funding from fiscal year 2022 through 2026 to improve Class VI well permitting." Anticipated benefits of this evaluation include "increased assurance that the EPA is making effective use of available resources to . . . efficiently manage the influx of permit applications."

While efforts to enhance the efficiency of the Class VI well permitting program are positive and should be pushed forward, it is unclear what the outcome of the Inspector General's evaluation will be and whether there will be impacts on pending Class VI applications that would delay CCS projects.

C. Significant Additional Hydrogen Pipeline Infrastructure Will be Needed to Connect the Regional Clean Hydrogen Hubs and Enable the "Low-GHG" Hydrogen Economy Necessary to Support Achievability Throughout the Electric Sector.

EPA's interest in hydrogen as a technology to reduce power sector emissions is well-founded and is shared by EEI's member companies. EEI and its members are working to make clean hydrogen commercially available at scale. We are engaged in pilot and demonstration projects across the clean hydrogen value chain, including participating in approximately half of the Regional Clean Hydrogen Hub (H2Hubs) proposals that DOE encouraged to submit full applications and being part of each of the seven H2Hubs that were selected for award on October 13, 2023; we are working with agencies and the National Laboratories to help advance clean hydrogen technology, delivery, and safety; and we are designing the power generation facilities of the future to be hydrogen capable.

However, electric companies also recognize that the U.S. is in the nascent stages of development of the clean hydrogen fuel that will be necessary to support hydrogen blending across the

economy and throughout the U.S. power sector in a manner that preserves reliability and affordability. Not only is hydrogen blending in the power sector not adequately demonstrated at present, but to progress from the current hydrogen market at the necessary scale to support reliable hydrogen blending in the power sector, a number of barriers must be overcome. Midstream infrastructure buildout is among these.

In the Proposed 111 Rules, EPA cited the H2Hubs as support for its reliance on low-GHG hydrogen. *See, e.g.,* 88 *Fed. Reg.* at 33,309 ("Given the growth in the hydrogen sector and Federal funding for the H2Hubs, which will explicitly explore and incentivize hydrogen distribution, the EPA therefore believes that hydrogen distribution and storage infrastructure will not present a barrier to access for new combustion turbines opting to co-fire with 30 percent low-GHG hydrogen by volume in 2032 and to co-fire with 96 percent low-GHG hydrogen by volume in 2038."). At least three of the H2Hubs that received awards on October 13, 2023, are in states with limited existing natural gas pipeline infrastructure. Therefore, regardless of whether existing natural gas pipelines can be retrofitted to carry hydrogen, these H2Hubs will require significant pipeline buildout to support a hydrogen system that would enable achievability throughout the electric sector. In addition, the H2Hubs that were selected are in states that are mainly along the borders of the United States. As a result, while the H2Hubs program may promote development of pipeline infrastructure to transport hydrogen, additional development beyond the H2Hubs program will be needed to support midstream infrastructure buildout across the center of the United States, much of the southeast, and the Northeast.

The H2Hubs program has significant potential to catalyze the development of a U.S. clean hydrogen economy, and DOE's efforts on H2Hubs are necessary first steps. However, barriers to hydrogen development remain and raise questions about the timing and scope of the hydrogen system that will be necessary to support achievability *throughout* the electric sector, which EPA should take note of as it works to finalize the Proposed 111 Rules.

V. EPA Should Conduct An Information Collection Request (ICR) For The Existing Natural Gas Turbine Fleet.

As EEI described in it's August 2023 comments, the existing natural gas-based turbine fleet is diverse, from a size, technology, efficiency, emissions, and operations perspective, which makes developing a working regulatory scheme to address these units under CAA section 111(d) challenging. EPA's approach to regulating existing natural gas-based turbines—covering those combined cycle units that have a nameplate capacity equal to or greater than 300 MW and operate at a capacity factor of greater than 50 percent—would benefit from additional analysis and data to support reasoned decision making. One issue that EPA should affirmatively address is the significant role that existing natural gas-based turbine generation plays in overall system reliability and the technical and practical challenges associated with retrofitting existing natural gas-based units.

As the fleet continues to transition, dispatchable resources like natural gas-based turbines will continue to play a critical and evolving role in integrating increasing amounts of renewable generation and providing essential reliability services to allow for the ongoing retirement of the coal-based generation fleet while preserving customer affordability. Until emissions-free dispatchable resources become available at commercial scale, existing natural gas-fired units need to be retained to support grid reliability. Natural gas-based turbines are significantly more

flexible than coal-based units given their ability to ramp quickly, especially as compared to other dispatchable units, including nuclear units and coal-based units—e.g., they are able to come online quickly and provide power to the grid much faster while also being able to ramp down as needed. This fast-ramping ability both minimizes emissions related to start up and shut down and also helps to avoid emissions by supporting the integration of variable renewable generating resources.

Some units may operate at significant capacity factors—greater than 80 percent—for long periods of time to respond to system considerations, such as when a coal-based unit is retired and other resources might not be fully online, resulting in highly efficient generation from an emissions rate perspective.[44] Other units might instead respond to intermittent system needs, operating at capacity factors of less than 15 percent while still providing essential reliability services and helping to reduce overall system emissions. Further complicating matters, units that operate at high or low (or even in between) capacity factors for long stretches are not guaranteed to remain in that mode while demand for their energy and other services changes continuously in response to system needs. Units are obligated to respond when called upon based on these system needs, which will change further in coming years as the generation mix of the grid continues to evolve.

[44] In general, the emissions rate of an individual unit is more efficient (resultingly, lower) when it run at higher capacity factors. Units that operate at lower capacity factors have concomitantly higher, less efficient emissions rates despite having fewer mass emissions of CO_2.

Many of these units likely will be required to operate differently in response to the changing grid mix and the resulting changes in system needs.[45] These changes will have a significant impact on the emissions and emissions rates associated with these units. This includes the potential for: units switching between operational modes (e.g., simple v. combined cycle) to respond to voltage demands; units in specific locations running more or less often to respond to generation intermittency, transmission congestion or new transmission coming online changing the dynamics of the operating grid; and the aging of the existing gas turbine fleet, which will continue as the fleet transition continues. Each of these scenarios will result in a significant impact on the efficiency rates and the CO_2 profile of existing gas-based turbines and the associated efficiency rates for those units. Consequently, the sheer diversity of the types of units and the range of possible operating characteristics of the existing turbine fleet makes determining an implementable BSER for these units extremely difficult.

EPA should address these salient issues in its analysis of the feasibility of the proposed standards, which would be effective far into the future. As noted in EEI's August 2023 comments, the Agency should re-propose or significantly supplement its proposal for existing natural gas to develop additional flexibilities that can help reduce emissions from the existing natural gas fleet while integrating additional renewables on to the grid in a reliable and affordable way for customers. This also would provide necessary additional record material to underpin EPA's analysis and regulatory approach. One goal of such an action would be to avoid potential unintended consequences of the current proposed approach, which include limiting the

[45] *See, e.g.*, Eric Larson, et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Final report (Princeton University, Oct. 2021), https://netzeroamerica.princeton.edu/the-report.

operations of the most efficient units in the existing fleet, particularly during peak demand and extreme events, without significant reductions in emissions.

Fundamentally, one of the issues that EPA and the regulated sector will need to solve to help craft workable standards for existing natural gas-based turbines is to better understand how those units are likely to operate in the future in order to provide a regulatory scheme that can both reduce emissions and meet system reliability needs as the clean energy transition. In order to do so, EPA should utilize the authority under CAA section 114 to issue an information collection request (ICR) to obtain additional data on both the current and future operation of the existing gas turbine fleet. Issuing an ICR expeditiously would show continued progress between the Agency and stakeholders on this important concern. An ICR would also help EPA bolster its record on the proposed existing gas guidelines. Electric companies would work diligently to respond to such a request on an expedited timeframe to ensure that the Agency had necessary data available to it as it works to address emissions from the existing natural gas-based turbine fleet. EPA should do so.

VI. Conclusion.

EEI appreciates the opportunity to continue to actively and constructively engage with EPA on the Agency's full suite of climate and environmental regulations for fossil-based power plants. We look forward to engaging with EPA and stakeholders on these issues as the Agency works to finalize the Proposed 111 Rules. Please contact Alex Bond at abond@eei.org (202-508-5523) if you have any questions regarding EEI's comments.

APPENDIX A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

December 16, 2011

MEMORANDUM

SUBJECT: **The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard**

FROM: **Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance**

TO: **Regional Administrators (EPA Regions I-X)**
Regional Counsel (EPA Regions I-X)
Regional Enforcement Division Directors (EPA Regions I-X)
Air Division Directors (EPA Headquarters and Regions I-X)

I. STATEMENT OF POLICY

It is the EPA's obligation to ensure compliance with environmental laws designed to protect public health and welfare. Where there is a conflict between timely compliance with a particular requirement and electric reliability, the EPA intends to carefully exercise its authorities to ensure compliance with environmental standards while addressing genuine risks to reliability in a manner that protects public health and welfare.

Pursuant to Section 112 of the Clean Air Act ("CAA"), the EPA finalized national emission standards for hazardous air pollutants ("NESHAP") from electric generating units ("EGUs") in December 2011. These standards, commonly known as the "Mercury and Air Toxics Standards" ("MATS"), adopt emission limits on mercury, acid gases and other toxic pollutants for affected coal and oil-fired EGUs. Many existing sources will comply with the MATS by controlling their emissions, while others (typically older, smaller, less efficient units) may choose to cease operations rather than install control technologies.

The EPA believes that all affected sources will be able to comply with the MATS within the compliance period specified by Section 112(i)(3) of the CAA (including, as applicable, any

extensions permitted under Section 112(i)(3)(B)) (the "MATS Compliance Date"). The EPA's analysis projects only a modest level of retirements, and the Agency does not anticipate that such retirements will lead to resource constraints that would adversely affect electric reliability.

Nonetheless, the EPA acknowledges that there may be isolated instances in which the deactivation or retirement of a unit or a delay in installation of controls due to factors beyond the owner's/operator's control could have an adverse, localized impact on electric reliability that cannot be predicted or planned for with specificity at the present time. In such instances, sources could find themselves in the position of either operating in noncompliance with the MATS or halting operations and thereby potentially impacting electric reliability.

The EPA is issuing this policy memorandum to describe its intended approach regarding the use of Section 113(a) administrative orders ("AOs") with respect to sources that must operate in noncompliance with the MATS for up to a year to address a specific and documented reliability concern. This enforcement policy is limited in application to units that are critical for reliability purposes. Some sources will be able obtain a broadly available one-year extension pursuant to Section 112(i)(3)(B). A source that qualifies for a one year extension from its permitting authority may also qualify for an AO at the end of its extension, provided that it falls within the terms of this policy. The EPA believes that there are likely to be few, if any, cases in which it is not possible to mitigate a reliability issue within four years, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under this policy.

This policy does not address situations where a reliability critical unit needs more than one year to come into compliance after the MATS Compliance Date. The policy also does not address delays in installations of controls and/or other instances of noncompliance with the MATS for units that are not reliability critical. The EPA intends to handle such scenarios as it has in the past, by assessing each situation on a case-by-case basis, at the appropriate time, to determine the appropriate enforcement response and resolution.

As set forth below, in light of the complexity of the electric system and the local nature of many reliability issues, the EPA will, for purposes of using its Section 113(a) AO authority in this context, rely for identification and/or analysis of reliability risks upon the advice and counsel of reliability experts, including, but not limited to, the Federal Energy Regulatory Commission ("FERC"), Regional Transmission Operators ("RTOs"), Independent System Operators ("ISOs") and other Planning Authorities as identified herein, the North American Electric Reliability Corporation ("NERC") and affiliated regional entities, and state public service commissions ("PSCs") and public utility commissions ("PUCs"). The EPA will work with these and other organizations, as appropriate, to ensure that any claims of reliability risks are properly characterized and evaluated.

The EPA is committed to achieving compliance with the MATS while ensuring electric reliability.

The policies established in this document supplement other applicable policies, and are intended to assist government personnel in determining the appropriate response to noncompliance. These policies and procedures are not intended to, nor do they, constitute a rulemaking by the EPA. These policies and procedures do not create a right or a benefit, substantive or procedural, that is enforceable at law or in equity by any person. The EPA reserves the right to act at variance with these policies and to change them at any time without public notice. Further, nothing in this document should be construed to affect the EPA's analysis of, or reaction to, an imminent and substantial endangerment to human health.

II. SUMMARY OF LEGAL REQUIREMENTS AND AUTHORITIES

Section 112 of the CAA establishes compliance deadlines for existing sources to meet standards promulgated under that provision, such as those included in the MATS rule.[1] Specifically, Section 112(i)(3)(A) provides:

> After the effective date of any emissions standard, limitation or regulation promulgated under this section and applicable to a source, no person may operate such source in violation of such standard, limitation or regulation except, in the case of an existing source, the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard.
>
> *See, also* 40 CFR 63.9984.

The CAA and its implementing regulations provide specific conditions under which extensions may be granted to this three year compliance period and under which other compliance time periods may apply. *See, e.g.,* Section 112(i)(3)(B), (4)-(6). In particular, Section 112(i)(3)(B) provides:

> The Administrator (or a State with a program approved under subchapter V of this chapter) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) of this section if such additional period is necessary for the installation of controls.

Section 113 of the CAA authorizes the Administrator to bring enforcement actions against sources in violation of CAA requirements, seeking injunctive relief, civil penalties and, in certain circumstances, other appropriate relief. The EPA also has the discretion to agree to negotiated

[1] Except as otherwise provided under Section 112(i)(3)(B), the MATS requires compliance within three years of the effective date, the statutory maximum.

resolutions including, for example, expeditious compliance schedules with enforceable compliance milestones.

III. THE EPA'S ENFORCEMENT RESPONSE TO BRING RELIABILITY-CRITICAL UNITS INTO COMPLIANCE

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly years in advance of the date when a violation may occur. The Agency is doing so now with respect to the MATS to provide confidence with respect to electric reliability. EGUs may be needed to operate to maintain the reliability of the electric grid when they would prefer, or could be required, to halt operations temporarily (until controls can be installed) or indefinitely (through deactivation of a unit). This policy describes the EPA's intended enforcement response in such instances. The policy is informed, as are our enforcement actions in general, by the need to find an appropriate balance between critical public interests, bearing in mind the resources and process time required for any enforcement response.

Some sources may take all steps necessary to comply with the MATS, but may nevertheless be needed to operate in noncompliance with the MATS to address concerns with electric reliability. In the event that such sources are interested in receiving a schedule to come into compliance while operating, the EPA intends, where necessary to avoid a serious risk to electric reliability, and provided the criteria set forth herein are met, to issue an expeditious case-specific AO to bring a source into compliance within one year. *See* Section 113(a). Any such AOs would be issued on or after (not before) the MATS Compliance Date and would be limited to units that are required to run for reliability purposes that (A) would otherwise be deactivated, or (B) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay.[2]

The Agency is cognizant that early planning will play a key role in allowing for the identification, and timely mitigation, of any potential reliability issues. The EPA expects that owners/operators will begin compliance planning early, and will provide early notice of their compliance plans to the appropriate reliability entities. We further expect that entities with responsibility for reliability planning and coordination will develop and maintain system-wide reliability plans for the units within their purview, and that this regional reliability planning will provide early identification of units that are critical for reliability purposes. Early notice and planning can discourage delays in coming into compliance, encourage timely action to avoid or mitigate reliability concerns, and minimize the need for issuance of AOs of the type described herein.

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[2] The EPA does not intend to seek civil penalties for violations of the MATS that occur as a result of operation for up to one year in conformity with an AO issued in connection with this policy, unless there are misrepresentations in the materials submitted in a request for an AO.

The EPA also recognizes the need for advance planning with regard to the future availability of any reliability critical EGUs to operate as needed to maintain electric reliability. Accordingly, although an AO cannot be issued under Section 113(a) prior to the MATS Compliance Date, the EPA intends – where the owner/operator has timely submitted a complete request and has provided appropriate cooperation – to give the owner/operator as much advance written notice as practicable of the Agency's plans with regard to such an AO.

To qualify for an AO in connection with this policy, an owner/operator should, at a minimum, take the following steps.[3, 4]

A. Provide early notice of compliance plans. Within one year after the effective date of the MATS, an owner/operator should provide written notice of its compliance plans, with regard to each EGU it owns or operates, that identifies (a) the units it plans to deactivate and the anticipated dates of deactivation and (b) the units for which it intends to install pollution control equipment or otherwise retrofit and the anticipated schedule for completion of that work, to the Planning Authority for the area in which the relevant EGU or EGUs are located.[5]

B. Timely request an AO for a unit that may affect reliability due to deactivation. In addition to the elements identified in III(A) above, for a unit that is required to run for reliability purposes that would otherwise be deactivated:

1. An owner/operator should, no less than 180 days prior to the MATS Compliance Date, submit electronically to (a) the Director of the Air Enforcement Division in the EPA's Office of Enforcement and Compliance Assurance, and (b) the Regional Administrator of the EPA Region in which the EGU is located, with a copy to FERC, at an office of its designation, (collectively, "AO Request Recipients") a written request for an enforceable compliance schedule in an AO for the unit, which includes information responsive to each of the elements specified in III(D) below.

2. At the same time the unit owner/operator submits its request for an AO, an owner/operator should also provide notice that it is seeking such an AO to (a) the Planning Authority, (b) any state PUCs/PSCs with regulatory jurisdiction with

[3] The EPA will evaluate each request for an AO for a unit that is required to run for reliability purposes on a case-by-case basis.

[4] Any notice, request or other submission discussed in this memorandum should conform to the standard business practice of the receiving entity for the submission of information, including any requirements governing submission of Confidential Business Information and/or other confidential information.

[5] Planning Authority is the entity defined as such in the "Glossary of Terms Used in NERC Reliability Standards," available at: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf, or any successor term thereto approved by FERC, and includes, in relevant jurisdictions, RTOs and ISOs.

regard to the relevant EGU,[6] (c) any state, tribal or local environmental agency with permitting authority under Titles I and V of the CAA, and any tribal environmental agency that does not have such authority, with jurisdiction over the area in which the EGU is located (collectively, "AO Notice Recipients").

C. Timely request an AO for a unit that may affect reliability due to delays related to the installation of controls. In addition to the elements identified in III(A) above, for a unit that that is required to run for reliability purposes that, due to factors beyond the control of the owner/operator, has a delay in installation of controls or needs to operate because another unit has had such a delay:

1. An owner/operator should, within a reasonable time of learning of a delay that it believes may result in a unit being unable to comply by the MATS Compliance Date, provide to the Planning Authority for the area in which the relevant EGU or EGUs are located, written notice of the units impacted by the delay, the cause of the delay, an estimate of the length of time of the delay, and the timeframe during which it contemplates operation in noncompliance with the MATS.

2. An owner/operator should, within a reasonable time of learning that it is critical to reliability to operate a unit described in the preceding paragraph in noncompliance with the MATS after the MATS Compliance Date, submit electronically to the AO Request Recipients a written request for an enforceable compliance schedule in an AO for the unit, which includes information responsive to as many of the elements specified in III(D) below as it is possible to provide at that time.

3. At the same time the unit owner/operator submits its request for an AO, an owner/operator should also provide notice that it is seeking such an AO to the AO Notice Recipients.

D. Submit a complete request for an AO. The following elements should be included in a request for an AO in connection with this policy:[7]

1. Copies of the early notice provided to the Planning Authority pursuant to III(A) or an explanation of why it was not practicable to have provided such notice and a demonstration that such notice was provided as soon as it was practicable.

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[6] PUCs/PSCs may also wish to obtain the information identified in III(A), either by requesting that an owner/operator over which the PUC/PSC has jurisdiction provide such information directly, or by requesting such information from the relevant Planning Authority.

[7] The EPA may request additional information from the unit owner/operator. The speed with which the EPA evaluates a request and its ultimate response will be related to the timeliness, completeness, and quality of the submittal.

2. Written analysis of the reliability risk if the unit were not in operation, which demonstrates that operation of the unit after the MATS Compliance Date is critical to maintaining electric reliability, and that failure to operate the unit would: (a) result in the violation of at least one of the reliability criteria required to be filed with FERC, and, in the case of the Electric Reliability Council of Texas ("ERCOT"), with the Texas PUC,[8] or (b) cause reserves to fall below the required system reserve margin.

3. Written concurrence with the analysis in III(D)(2) by, or a separate and equivalent analysis by, the Planning Authority for the area in which the relevant EGU or EGUs are located, or, in the alternative, a written explanation of why such concurrence or separate and equivalent analysis cannot be provided, and, where practicable, any related system wide analysis by such entity.

4. Copies of any written comments from third parties directed to, and received by, the owner/operator in favor of, or opposed to, operation of the unit after the MATS Compliance Date.

5. A plan to achieve compliance with the MATS no later than one year after the MATS Compliance Date, and, where practicable, a written demonstration of the plan to resolve the underlying reliability problem and the steps and timeframe for implementing it, which demonstrates that such resolution cannot be effected on or before the MATS Compliance Date.

6. An identification of the level of operation of the unit that is required to avoid the documented reliability risk in III(D)(2) and, consistent with that level, a proposal for operational limits and/or work practices to minimize or mitigate any HAP emissions to the extent practicable during any operation not in full compliance with the MATS.

In evaluating a request for an AO submitted in contemplation of this policy, although the EPA's issuance of an AO is not conditioned upon the approval or concurrence of any entity, the EPA intends to consult, as necessary or appropriate on a case-by-case basis, with FERC and/or other entities with relevant reliability expertise.

[8] Because ERCOT oversees intrastate transmission of electricity solely within Texas and does not provide for interstate transmission, ERCOT files reliability criteria with the Texas PUC.