Additional Considerations for Clean Air Act Section 111 Compliance Flexibility for Both New and Existing Units

The U.S. Environmental Protection Agency (Agency or EPA) is moving forward with regulations under Clean Air Act (CAA) section 111 to address greenhouse gas (GHG) emissions (primarily carbon dioxide (CO_2) emissions) from fossil-based electric generating units (EGUs or units). The existing regulatory framework and recent court decisions provide some limitations, but also some latitude, to EPA regarding how to set standards to address EGU emissions. Significantly, EPA has a notable amount of flexibility in how standards are set and how the options for compliance are designed. This flexibility is essential to achieving emissions reductions from new and existing EGUs, both now and in the future, while also supporting the delivery of affordable and reliable electricity to customers.

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. EEI members provide electricity for more than 235 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than seven million jobs in communities across the United States. EEI member companies invest more than $130 billion annually to make the energy grid smarter, cleaner, more dynamic, more flexible, and more secure in order to provide affordable and reliable electricity to customers. EEI's members are committed to getting the energy they provide as clean as they can as fast as they can, keeping affordability and reliability front and center.

EEI members are in the middle of 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, and renewable energy resources, energy efficiency and demand-side management, technological improvements, changing customer, investor and owner expectations, federal and state regulations and policies, and the increasing use of distributed energy resources. EEI members are well-positioned to continue to lead the nation's clean energy transformation. Across the industry, 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.

EPA has multiple options available to it in determining what flexibilities should be offered to states and units. EPA's approach to these in the context of these new rulemakings should be expansive: flexibility should be considered concurrently and holistically, with the goal of providing maximum flexibility for both new and existing units to successfully capture and aid the industry's ongoing clean energy transformation, as well as to aid states in the development of approvable compliance plans. This white paper focuses on providing that flexibility through the creation of "opt-in" approaches to compliance with CAA section 111.

EPA traditionally sets emissions rates requirements under CAA section 111, expressed as pounds of CO_2 per megawatt hour (lbs. CO_2/MWh). These limitations have typically functioned to ensure that new units are operating as efficiently as possible, thus minimizing emissions. At present there are limited options for reducing emissions other than efficiency. In the near future, however, new gas units may blend hydrogen or use carbon capture technology to reduce emissions in addition to or instead of efficiency measures. When adequately demonstrated, EPA could support adoption of these technologies in multiple ways: including setting a hydrogen *or* carbon capture "capable" standard in conjunction with this traditional emissions rate-based efficiency approach or offering a mass-based compliance option for new units in conjunction with or as an alternative to a rate-based efficiency approach. These approaches could ensure that any new generation not only would use the most efficient technologies available—as regulated by the lbs. CO_2/MWh emissions limitation or the mass-based compliance option in terms of tons of CO_2—but also could enable future emissions reductions once hydrogen or carbon capture technologies[1] are demonstrated and cost effective for the power sector, while supporting reduced outage times associated with retrofits.[2]

One key flexibility available to EPA is the creation and use of various subcategories that would provide additional compliance approaches for owners and operators of units that "opt-in" to these compliance regimes. These subcategories would be grounded in EPA's discretion under the CAA to distinguish among classes, types, and sizes of affected units within categories of sources. Indeed, EPA has used this type of approach for the sector before—for the steam electric effluent limitation guidelines (ELGs) under the Clean Water Act, the mercury and air toxics standards

[1] As discussed at length in EEI's November submission to EPA, hydrogen co-firing is an emerging energy technology that holds tremendous promise as a tool to aid in reducing emissions across a variety of sectors and applications, including potential use in EGUs. CCS technology, while still in the development stage, has the future potential to accelerate the rate of carbon emissions reductions, and help maintain reliability of the energy grid. Costs remain an issue for both options at present. In addition, both hydrogen co-firing and CCS technology face a number of other challenges that will need to be overcome to enable commercial scale use throughout the industry. Government and industry are investing in addressing these cost, technology, and infrastructure challenges. With that investment, there is reason to be optimistic that these challenges will be overcome in this decade.

[2] "Capable" standards—sometimes referred to as "ready" or "capable-to-ready" standards—are not self-executing. Any future emissions limitations for then-existing units based on hydrogen co-firing or CCS technology would have to be the result of a future rulemaking under CAA section 111(d) in which EPA would analyze whether such technologies had been adequately demonstrated considering all the statutory factors. The statutory text of CAA section 111 itself supports a flexibility-centered approach to both standard setting and compliance, but not automatic increases in the stringency of standards.

The CAA requires EPA to determine the Best System of Emission Reduction (BSER) as a first step in setting standards to limit emissions from new or existing sources in a source category. These standards are required to reflect the level of emission limitation that is achievable using that BSER by sources within that category. While EPA has often expressed these limitations as emissions rates, the only statutory requirement is that the standards of performance must reflect the "degree of emission limitation" that EPA has determined is "achievable through" the BSER. EPA has latitude to express standards through non-rate means as long as those stay within the statutory bounds of being adequately demonstrated and achievable, taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements.

under CAA section 112, and others—providing broad flexibility that support the sector's continuing clean energy transformation. This paper highlights several potential subcategories that EPA could consider adopting in its upcoming rulemakings. This paper also discusses the ability to convert rate-based standards into mass-based compliance options, which provides both flexibility and more assured emissions reductions when paired with some of these opt-in subcategories. This paper discusses each flexibility—multiple approaches to setting standards for new units; mass-based compliance subcategories for new and existing units—in turn, below.

Approaches for New Gas-Based Units, Including Hydrogen and CCS Capable Standards

EPA can provide an alternative compliance option for new gas units by defining an optional "capable" requirement for new units. Such an approach would ensure that, in addition to any new generation using the most efficient technologies available—as regulated by the lbs. CO_2/MWh emissions limitation—these new units would enable future emissions reductions at lower costs, once hydrogen co-firing or carbon capture technologies are demonstrated and cost effective for the power sector.

Given differences in the availability of resources and infrastructure necessary to support the use of hydrogen co-firing and carbon capture at EGUs at this time, it is possible that there will be areas of the United States where either hydrogen co-firing or carbon capture are a feasible technology, but likely not both. Consequently, any such "capable" requirement for new EGUs should be set in the alternative—allowing EGUs to opt to meet either the hydrogen ready or the carbon capture ready standard instead of requiring EGUs to meet both.[3]

EPA also should allow mass-based compliance by developing a methodology to translate from rate-to-mass compliance for new gas units that could be used in conjunction with or in lieu of traditional rate-based efficiency or technology "capable" approaches.

1. *Hydrogen or CCS "Capable" Requirements*

EPA should consider specifying the requirements for hydrogen co-firing or carbon capture "capable" standards. In practice, compliance with these specifications would be best done via a certification made by the unit owner/operator that would be incorporated into and filed along with the new unit's air permit. This certification could consist of a narrative description outlining the research that the company has undertaken regarding actions necessary for any successful future retrofit, including technology options, estimated costs, access to fuel and/or pore space, among other factors.

As hydrogen co-firing and CCS technologies develop, plant requirements may change. The requirements discussed below are based on the current state of technology and may not be applicable in the future as technology advances. EPA should provide flexibility in defining the "capable" standards by acknowledging that these certifications may evolve over time and may

[3] The below discussion focuses on "at the unit" elements of a "capable" standard; it does not address the availability of hydrogen fuel or other infrastructure barriers for both hydrogen and CCS pipelines that exist. As discussed in EEI's November submission to EPA, these challenges are substantial and remain unresolved despite significant work and investment to address these concerns.

not all be necessary to deploy the technology. EPA not only should provide a pathway for plant owners to demonstrate "capable" through an alternative engineering assessment compliance option but should address these issues on a unit-specific basis via the permitting process.

In addition to the narrative, a new facility could demonstrate that is "capable" through other concrete actions. The elements of a hydrogen co-firing capable and a CCS-capable unit are discussed below.

Elements of a Hydrogen Co-Firing "Capable" Standard

- *Consideration of additional space for future hydrogen pipes in laying the foundation for the turbine*. Some new turbines that could be capable of high hydrogen blending levels in the future will need additional space around the turbine to accommodate larger fuel piping. The installation of this larger piping would be more costly once the facility is constructed and in operation. Owner/operators could certify, if the turbine manufacturer anticipates needing additional space below the turbine for high levels of hydrogen blending in the future, that they have taken appropriate design steps to pour and construct foundations to accommodate these needs.

- *The consideration of additional space inside the Heat Recovery Steam Generator (HRSG) design for additional or future emission control systems*. Blending higher levels of hydrogen in turbines for power production decreases the overall CO_2 emissions from the unit, but also creates the potential for higher emissions of nitrogen oxides (NOx). In order to address the potential increased NOx emissions through the installation of additional, larger, or more advanced emissions control systems, owner/operators could certify that they have taken appropriate design steps to include necessary space in the power island to install these additional systems in the future to accommodate various hydrogen blend ratios.

- *Additional steps consistent with manufacturer needs and the generator's technology plan*. Owner/operators also could receive a certification from the original engine manufacturer (OEM) regarding the appropriate design steps—or provide their own explanation—for "at the unit" modifications that are foreseeable for successfully blending hydrogen in future years.

Elements of a Post-Combustion[4] Carbon Capture "Capable" Standard

- *Consideration of additional space for future CO_2 pipes from the facility*. Turbines appropriate for the installation of carbon capture systems in future years may need additional space surrounding the turbine in order to accommodate additional CO_2

[4] This paper discusses post-combustion "capable" requirements. There are emerging technologies that, if demonstrated, would limit CO_2 through a pre-combustion removal process. Because pre-combustion CO_2 removal would require significant design changes throughout the entire power island and facility, those are not addressed here as they would not lend themselves to a "capable" standard.

piping/pipelines to transport the captured CO_2 for storage or utilization. CO_2 piping will need to have space at the effluent of the capture unit, which may require that building foundations, piping, and duct banks be routed to preserve this space for future use. Owner/operators could state, if the turbine manufacturer anticipates additional space for CO_2 piping will be needed in the future, that the owner/operator has taken appropriate design steps to accommodate these needs.

- *The consideration of additional space in turbine design for the future installation of carbon capture systems*. Installation of carbon capture systems will require additional space behind, in front of, or near the turbine island in order to accommodate installation of this control technology. Owner/operators could state that they have taken appropriate design steps to include space in or near the turbine island to install these additional systems in the future.

- *Consideration of land use needs directly adjacent to the facility.* The equipment required to divert the exhaust gas and remove, cool, and compress the CO_2 requires nearly the same amount of space and same capital requirements as the gas-based unit itself. Currently, several different technologies are being pursued to be able to commercially achieve CCS, all of which would require significant additional space for installation. Owner/operators could state that they have taken appropriate design steps to include space in or near the facility to install these additional systems in the future.

- *Additional steps consistent with manufacturer needs*. Owner/operators also state what "at the unit" modifications that are foreseeable for successfully incorporating carbon capture systems in the future, including any additional power needs to operate the carbon capture.

It is worth noting that both hydrogen co-firing and CCS technologies are evolving and hold significant promise. However, overly prescriptive requirements could hinder the best available technology from being installed once it is commercially available given the potential array of future developments for these technologies. Accordingly, it is important that EPA strike a balance between "capable" requirements and ensuring that critical maximum flexibility is available to recognize and harness technology innovation.[5]

2. *Mass-Based Compliance for New Natural Gas Units*

As discussed in more detail below, there are several advantages to be gained from converting rate-based emissions limitations into mass-based tonnage budgets for regulated units. Since decreases in (or limits of) a unit's capacity factor have a direct impact on its CO_2 emissions profile, states, EPA, and units can employ a mass-based approach to leverage the emissions reductions benefits of a decrease in capacity factors, while preserving maximum operational

[5] Since these technologies are still under development, EPA should work to provide flexibility and ongoing guidance as new information becomes available. Similar to EPA's Reasonably Available Control Technology, Best Achievable Control Technology, Lowest Achievable Emission Rate (RACT, BACT, and LAER, respectively) Clearinghouse, EPA should maintain a central database of this technology information to aid permitting agencies and future case-by-case permitting determinations.

flexibility to support overall system reliability by preserving the availability of units for resource adequacy, particularly during extreme weather events or other emergency conditions. For new natural gas-based units, this could be realized by agreeing to reduced utilization via capacity factor limits that are set below a "full" operations baseline in order to develop an operating tonnage budget on a unit-specific basis, for both for combined cycle and combustion turbine operation. Some unit owners/operates might want to pursue such an approach. This type of approach also could ameliorate local reliability concerns.

Mass-based tonnage budgets also provide flexibility for phasing in new technologies to reduce carbon emissions, such as CCUS or hydrogen co-firing. In these examples, a unit can initially comply with a massed-based tonnage budget through reduced operation. But, the option to retrofit and transition to compliance through hydrogen co-firing or CCUS provides an inherent incentive because the unit would be able to return to operations at a higher utilization rate. The advantage of this pathway is that it would provide flexibility in the compliance timeline and choice of technology adoption, while also avoiding the need to set a prescriptive "capable" standard for a technology that is still in early development stages.

<u>Mass-Based Compliance Options</u>

As noted above, mass-based compliance options provide significant and important operational and compliance flexibility. The Agency can and should authorize mass-based compliance. EPA has long used mass-based compliance for a wide array of CAA programs. For existing coal-based EGUs, these mass-based approaches work in conjunction with EPA's ability to create subcategories to facilitate compliance with CAA section 111(d) guidelines for existing sources or can be used on their own as part of a unit-specific approach included in a state plan. For purposes of this paper, a few representative examples show how mass-based calculations and approaches can work.[6] An illustrative unit and two separate scenarios based on an entirely hypothetical ten percent reduction in the emissions rate through the application of an unspecified "best system of emission reduction" demonstrates how to convert a rate-based emissions limitation into a mass-based tonnage budget:

[6] For purposes of these hypotheticals, certain assumptions (e.g., capacity factors and emissions rates) have been kept constant for illustrative purposes. Real world operations—with their attendant capacity factor variations and resulting changes in emissions rates—will be more variable and more complex. Any application of these principles as part of a state plan must be the result of a unit-specific inquiry. That said, simplicity in assumptions in this paper is intended to showcase how rate-to-mass conversions can work and be paired with other flexibilities while preserving the significant emissions reductions and environmental certainty that can be associated with mass-based approaches. These examples also focus on existing coal-based units but could be applicable to all fossil-based units should EPA move forward with CAA section 111(d) guidelines for existing gas units at a future date.

Hypothetical Unit – Baseline Case

Unit Size (nameplate capacity):	650 MW
CO_2 Emissions Rate:	2,075 lbs. CO_2/MWh
2020 Capacity Factor:	57%
2020 Generation (MWh):	3,250,000
2020 CO_2 Emissions (tons):	3,370,000

Unit Assumption Scenario 1

Unit Size (nameplate capacity):	650MW
BSER Application:	10% Reduction in Emissions Rate (1,875 lbs. CO_2/MWh)
Annual Capacity Factor:	57%
Annual Generation (MWh):	3,250,000
CO_2 Emissions (tons):	3,046,875
Difference (tons):	323,125

Unit Assumption Scenario 2

Unit Size (nameplate capacity)	650MW
BSER Application:	N/A (2,075 lbs. CO_2/MWh)
Annual Capacity Factor:	25%
Annual Generation MWh:	1,424,000
CO_2 Emissions (tons):	1,477,000
Difference (tons):	1,893,000

<u>Retirement Subcategory</u>

EPA should proactively include a subcategory that allows for units to opt-in to a federally enforceable retirement commitment as part of compliance with regulations for existing sources under CAA section 111(d). EPA has adopted a similar approach recently in the context of the Clean Water Act. EPA included a subcategory for the cessation of coal in the 2020 Steam Electric ELG Reconsideration Rule (2020 ELG Rule) to allow certain units the ability to forego compliance with new effluent limitations if the unit ceased combustion of coal by December 31, 2028. For units seeking to qualify as an electric generating unit that would achieve permanent cessation of coal combustion by December 31, 2028, those units filed a Notice of Planned Participation (NOPP) no later than October 13, 2021 (one year after the rule went into effect) to opt-in to the cessation of coal subcategory. Each NOPP includes enforceable retirement dates, timelines, and interim milestones, among other requirements.[7] EPA could adopt the framework

[7] The requirements include the expected date that each EGU is projected to achieve permanent cessation of coal combustion; whether each date represents a retirement or a fuel conversion; whether each retirement or fuel conversion has been approved by a regulatory body; what the relevant regulatory body is; a copy of the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELG; certification of EGU cessation or other documentation supporting that the electric generating unit will permanently cease the combustion of coal by December 31, 2028, and; a timeline to achieve

of this approach incorporating the ability to retire units in both 2028 and in years beyond that as part of any CAA section 111(d) implementation plan.

Using this as a model, EPA should craft a retirement subcategory under CAA section 111(d) by including similar requirements for retiring units. Critically, a retirement subcategory would result in significant avoided future emissions, which would result in greater overall reductions than those that could be expected from any existing source guidelines and/or state plans that only provide emissions limits for these units. EPA should consider applying this subcategory to units retiring in both 2028 and in years beyond consistent with the timeframes in any existing source guideline and the ongoing clean energy transition plans companies are executing.

Using Unit Assumption Scenario 1, and assuming constant operations outlined, EPA could expect that, over a hypothetical eight-year program running from 2024-2032, total CO_2 emissions reductions of approximately 2,700,000 tons through the application of the BSER. However, should the same unit opt-in to the retirement subcategory and cease operations in 2028 instead of operating through 2032, the total avoided emissions over the same time period would instead be approximately 13,500,000 total tons. Moreover, as the unit would have ceased operations, these emissions reductions would be permanent.

Given this magnitude of reduced and avoided emissions, at minimum, EPA should both allow those units that already have opted into the coal cessation subcategory in the 2020 ELG Rule to provide the NOPP to the relevant state as it designs any CAA section 111(d) implementation plan—which would enable the state to determine that no additional requirements apply to the units slated for closure—consistent with the statutory authority to consider the remaining useful life of a unit, and also submit other enforceable shutdown commitments by and beyond 2028 given the prevalence of other commitments made by companies into the early 2030s. This would be consistent with EPA's goal of providing a holistic approach to regulations across environmental media for the power sector. This could be accomplished by "deeming compliant" commitments to reduce utilization or retire units pursuant to other rulemakings—e.g., the 2020 ELG Rule or any reconsideration rulemaking, retirements consistent with consent decrees, or other rules impacting the power sector as identified by EPA—as satisfying the requirements under CAA section 111(d). Recently, EPA proposed an approach to acknowledge and account for these other requirements in the Good Neighbor Rule, and it should adopt such an approach to any future existing source guidelines.[8]

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the permanent cessation of coal combustion with interim milestones and the projected dates of completion. Units under this subcategory must also submit annual progress reports detailing the completion of any interim milestones listed in the NOPP since the previous progress report, provide a narrative discussion of any completed, missed, or delayed milestones, and provide updated milestones. It is worth noting that compliance with the 2020 ELG Rule is December 31, 2025.

[8] As technology develops, existing coal-based EGUs may be replaced with low or zero-emitting resources such as advanced nuclear, CCS, and hydrogen-fueled EGUs. Given the novel nature of these technologies, delays in permitting and construction might occur. EPA and States should work with plant owners to grant as much flexibility as possible around enforceable retirement

Reduced Utilization

EPA also could allow unit owners/operators to opt-in to a subcategory that tracks future reduced utilization of affected units as part of compliance with regulations for existing sources under CAA section 111(d). This could include limitations on unit capacity factors in future years, which would be represented by permit-specific limits on unit operations similar to those currently used in other contexts (e.g., synthetic minor limitations, 4x16 operating hours limitations, etc.). Capacity factor and operating hours limits, and their equivalents, would reduce emissions relative to operational baselines while also allowing these units to be available to address potential grid reliability events, particularly maximum generating events to respond to extreme weather or unexpected unit outages. While EPA proposed a backwards-looking capacity limitation subcategory in the 2020 ELG Rule, a more effective approach (and one that better responds to the changing needs of the electric grid as its transitions to greater integration of renewable generation) under CAA section 111(d) would be to impose such limitations on a forward-looking basis consistent with state Integrated Resource Plans—including forecasted load growth from beneficial and reliability considerations in order to appropriately target reduced utilization limitations consistent with both needs.[9]

Decreases in the capacity factor will have a direct impact on the CO_2 emissions profile of each unit. States, EPA, and units can also utilize a mass-based approach to leverage the potential benefits of a decrease in capacity factors. In short, EPA and states could use reduced utilization and lower capacity factors to set an operating tonnage budget on a unit-specific basis.[10] Drawing on the Unit Assumption Scenario 1, above, and assuming constant operations under the first scenario discussed, EPA could expect over an eight-year program running from 2024-2032 total emissions reductions based on the application of BSER to be approximately 2,700,000 tons of CO_2. However, under a reduced utilization approach, were a unit to take a purely hypothetical reduced utilization limitation of a 25% capacity factor (Unit Assumption Scenario 2) for the entire program period and translate that limitation into a tonnage budget, the total avoided emissions from this approach would instead be approximately 15,144,000 tons of CO_2 while also providing each unit a significant amount of operational flexibility within that compliance tonnage budget to ensure grid reliability, particularly during extreme weather events and other emergencies.

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commitments if retirement dates of existing EGUs are extended to accommodate in-service date delays for low or zero-emitting resources.

[9] Consistent with this type of approach, EPA also could consider crafting a limited-use subcategory that utilizes a capacity factor limitation paired with a long averaging period in order to preserve plants that provide important reliability services as needed. This is similar to approaches EPA has taken under CAA section 112 in the past.

[10] It also is worth noting that there are a variety of other factors to contemplate in a reduced utilization scenario, including rate structures and operations & maintenance requirements that must be addressed as facilities operate differently moving forward. These should be discussed and addressed during the state plan process on a unit-specific basis.

Instead of expressing these limits in terms of capacity factor, however, EPA, states, and unit owners/operations could also opt to create a total tonnage budget for a unit for some period of time. These tonnage budgets would be linked to reduced utilization limitations and would include enforceable budget caps with regular reporting regarding the size of the remaining budget, retirement dates (as applicable), and timelines for implementation and interim milestones, among other requirements. Once a unit had utilized the entirety of its tonnage budget, should it choose such an approach, then the unit would retire. This would allow for enforceability and guarantee environmental performance over the term of the budget and the program.

Combination Subcategory

EPA also could create a subcategory that combines the retirement and reduced utilization subcategories, creating one that includes both a future federally enforceable retirement limitation—likely in years beyond any existing or newly created retirement subcategory—with reduced utilization on the path to retirement. By way of example, if EPA had a retirement subcategory with a final retirement date of 2028, a combination subcategory could have an end date for retirement of 2032 with reduced utilization "stair steps" for every year beyond the retirement subcategory's 2028 date—e.g., 25%, 20%, 15%, 10%, retirement. This would provide environmental assurance in terms of the retirement, resulting in permanently avoided future emissions, and reduced emissions in the years leading up to retirement while allowing units to be available as critical capacity consistent with state plans and reliability concerns. The details of any such subcategory, which could be specific to a particular unit, ultimately should be determined by the state in the development of its implementation plan and approved by EPA.

Using the example from above, and assuming constant operations under Unit Assumption Scenario 1, again EPA could expect over an eight-year program running from 2024-2032 total emissions reductions based on the application of BSER to be approximately 2,700,000 tons of CO_2. For the final four years of that period, EPA could expect a reduction of 1,350,000 tons of CO_2. However, should the same unit utilize the combination subcategory and cease operations in 2032 with reduced utilization stairsteps as described above, the total avoided emissions from this approach and ultimate reductions would instead be approximately 7,572,000 tons of CO_2.