Considerations for Clean Air Act Section 111
Regulation of Existing Natural Gas 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. As EPA moves forward with setting the Best System of Emissions Reductions (BSER), it also has several potential technical and data challenges to consider, particularly with respect to existing gas-based units.

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. This paper, in addition to the two others that EEI has filed in EPA's nonregulatory docket[1] related to forthcoming regulations for fossil-based EGUs under CAA 111, is intended to highlight key issues—and offer potential options and solutions—identified by electric companies regarding the development of GHG emissions standards for existing natural gas-based EGUs.

As noted in our previous papers, EPA has a considerable 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 supporting the delivery of affordable and reliable electricity to customers. EPA has multiple options available to it in determining what flexibilities should be offered to states and EGUs. In addition, those papers noted that EPA's approach to these 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. Many of the flexibilities discussed in those papers—utilizing mass-based approaches, targeted and opt-in subcategories based on coordination with other rulemakings and utilization capabilities, and others—are also applicable to any existing source rulemaking for natural gas-based units.

However, the challenges EPA would face in the context of a section 111(d) rule for existing natural gas units are different and are the focus of this paper: the number of technical and data issues related to setting potential standards in a way that is technically and legally defensible. To the extent that EPA moves forward with regulations for existing natural gas units, such a move should support and facilitate the emissions reductions and clean energy progress already being

[1] EEI's November 2022 and February 2023 submissions are attached to this paper as well.

made by electric companies and their fleet transition plans. Any standards for the existing natural gas fleet should therefore work in concert with regulations for new units and the existing coal fleet—and these standards should be considered holistically.

Data Challenges in Setting BSER for Existing Gas-Based Units

EPA faces several challenges it must resolve before moving forward with any proposal for existing natural gas-based units under CAA section 111.[2] Chief among those issues is the sheer diversity of the types of units and the range of operating characteristics of the existing turbine fleet.

A brief description of natural gas-based turbines and the role they play in the power sector is warranted. Natural gas can be utilized in boilers, but is predominantly utilized in combustion turbines, which can either be designed as a simple cycle turbine or a combined cycle unit. A simple cycle combustion turbine (CT) combusts natural gas in a turbine that directly produces power. (This process is known as the Brayton cycle.) The combined cycle (CC) configuration combines the power produced from the simple cycle CT with a heat recovery steam generator (HRSG) which utilizes the exhaust heat of the CT to generate steam and then, via a steam turbine, produces additional power. The steam cycle is known as the Rankine cycle, and by combining it with the CT (Brayton cycle), the overall unit efficiency is increased. The power sector utilizes both for a variety of purposes—as discussed more below—but it is worth noting that while simple cycle turbines are less efficient from an emissions rate perspective than combined cycle units, they are able to reach full operating load more quickly given they do not utilize additional engineering components and processes that produce the Rankine cycle.

As the fleet continues to transition, 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. 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 EGUs—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.

Further, some units may operate at significant capacity factors—above 80 percent—for long periods of time to respond to system considerations, resulting in highly efficient generation from an emissions rate perspective.[3] Other units might instead respond to intermittent system needs, operating at capacity factors below 15 percent while still providing essential reliability services

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[2] This paper focuses specifically on combustion turbines; there are also units that utilize natural gas in boilers. Those units are subject to regulation under Subpart Ba, and face challenges more specific to boilers that utilize coal.

[3] 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.

and helping to reduce overall system emissions. In addition, units that operate at high or low (or even in between) capacity factors for long stretches are not guaranteed to remain in that mode as system needs continue to change. Units are obligated to respond when called upon based on those system needs, which will change further in coming years as the generation mix of the grid evolves and will require these units to operate differently. These changes will have a significant impact on the emissions and emissions rates associated with these units. This includes the potential for: units needing to switch between operation 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 that changes the dynamics of the operating grid; and the aging of the existing natural gas fleet. Each of these scenarios will result in a significant impact on the efficiency rates and the CO_2 profile of existing natural gas-based units and the associated efficiency rates for those units.

An additional consideration for EPA is the limited number of technical options to upgrade the performance of existing turbines. While there have been significant ongoing technological advances in turbine technology for both simple and combined cycle operations, the basics of turbine operation has not changed substantially. That is to say, while some of the materials and internal design components have been updated, the fundamental processes powering a turbine are essentially the same, the fuel has the same effective characteristics, and the additional technologies added for unit operations (heat recovery steam generator, selective catalytic reduction system) are all substantially similar. Further, operating efficiency also is correlated to the ambient conditions of gas turbines, including those operating in a combined cycle mode; several highly efficient operations are not available under all ambient conditions and vary based on the location of a CT.[4]

In essence, there are significantly fewer levers for technical and technological improvement for natural gas-based units when compared to coal-based units, which can gain efficiencies through upgrades to the steam boiler or several of the associated pollution control devices required with coal-based units, all of which result in a significantly less efficient combustion process when compared to producing electricity from a steam turbine. While there might be some technological improvements available through targeted upgrades to blade turbines or through maintenance optimization, these are not necessarily widely available, nor will those upgrades necessarily realize efficiency gains and environmental improvements from those units. It is also worth noting that efficiency projects both degrade over time and may not result in significant improvements—particularly if the unit is dispatched differently to respond to evolving grid needs and requirements.

All of these factors can impact a unit's emissions performance, but not all will impact every unit or result in the same potential emissions reductions. In short, it is difficult to define standard

[4] Retrofitting CCS for existing natural gas-based facilities will be difficult, as noted in EEI's prior submissions, given the likely space constraints and other technical challenges associated with retrofitting existing units with CCS technology. Many of these challenges—especially space constraints—also are likely a challenge to be overcome to increase hydrogen co-firing in natural gas-based units once hydrogen becomes available for the existing fleet.

levels that can capture the range of complex and variable operating conditions that impact unit performance. This includes the changing and widely different capacity factors; the evolving grid needs requiring different operations of gas-based turbines, including switching between operation modes; the impacts of ambient conditions on unit performance; and, the age of the existing fleet.

Further, it is not clear whether there are easily identifiable categories for efficiency improvements applicable across the existing natural gas-based fleet or whether, as noted, potential strategies to improve efficiency would yield emissions reductions. EPA should consider these challenges before moving forward with existing source guidelines for gas-based units under CAA section 111(d).

The Statutory Background of Section 111 Means Standards Must Be Demonstrated and Should Be Flexible

A brief discussion of the applicable statutory requirements and related caselaw is important for context as EPA considers setting standards for existing natural gas-based EGUs under CAA section 111(d). The CAA requires EPA to determine the 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.

CAA section 111(a) reads:

> The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

In making its BSER determinations, EPA must engage in two separate inquiries. First, EPA must establish that the proposed system of emission reduction is "adequately demonstrated." Second, EPA must determine that the proposed emission limitation is "achievable" using that system. *See Nat'l Asphalt Pavement Ass'n* v. *Train*, 539 F2.d 775, 785 (D.C. Cir. 1976) ("[I]t is the system which must be adequately demonstrated and the standard which must be achievable.")
Under section CAA 111(b), EPA then is required to set performance standards that reflect the BSER for categories of new sources, which includes modified and reconstructed sources. *See* 42 U.S.C § 7411(b)(1)(B).[5] These federal standards of performance must reflect the "degree of emission limitation" that EPA has determined is "achievable through" the BSER. 42 U.S.C. § 7411(a)(1). For *new* sources, including modified and reconstructed sources, EPA both determines the BSER *and* sets the emission limitation with which those sources must comply.

[5] This paper does not focus on modified or reconstructed units, but the discussion applies to these units equally.

EPA is required to review, and revise if appropriate, standards for new units at least every eight years. *See* 42 U.S.C § 7411(b)(1)(B).

Once performance standards are set for new units, CAA section 111(d) requires EPA to address existing sources. The statute instructs that EPA must "prescribe regulations which shall establish a procedure…under which each state shall submit to the Administrator a plan which …establishes standards of performance for any existing source for any air pollutant." While these standards of performance must also reflect the BSER identified by EPA, it is the states that set them, and thus the states that translate the BSER into emission limitations for existing sources in the state. States have more flexibility to address existing units under section 111(d) than EPA has with respect to new units under section 111(b). For example, states can consider the remaining useful life of existing EGUs and other factors when setting emissions standards for those units.[6]

In short, EPA defines BSER for both new and existing sources, but states have a significant role in translating that BSER into emissions limits for existing sources.

EPA Should Collect Additional Information About the Existing Gas-Based Fleet and Seek to Leverage Hydrogen as a Future Compliance Solution

Given the limited technological options available for reducing emissions and increasing efficiency at existing gas-based units—as discussed above—exploring the potential to reduce emissions by using a lower-carbon fuel in turbines is a potential future path for EPA and the sector. Hydrogen 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 turbines. However, as further detailed in EEI's November submission, currently there is a lack of operating projects at scale, both in the United States and abroad, as well as critical open U.S. regulatory, legal, and commercial questions.

As EEI noted in a previous submission to EPA, ensuring turbines have hydrogen co-firing capability will be significantly more straightforward for new units since certain design elements require additional space and engineering considerations. This includes the need to construct hydrogen piping or provide for additional space in the power island for necessary hydrogen blending systems, which can be designed prior to construction. For existing units, retrofit capabilities may be limited by space, design, age and other factors. While some existing gas-based unit designs may accommodate a greater ability to utilize hydrogen as a co-firing

[6] As discussed at length in EEI's November submission to EPA, existing legal precedent supports EPA setting standards that are based on commercially deployed and deploying technologies that can be achieved throughout the industry, allowing EPA to stay abreast of and mirror existing and actively deploying technological trends in the power sector. Under current case law, the "adequate demonstration" requirement means a technology must be commercially deployed/deployable across the industry such that the resulting standards are achievable throughout the industry. Demonstration projects are important to drive the development of critical carbon-free technologies, but their existence does not satisfy case law regarding adequate demonstration for CAA section 111 purposes.

alternative once that fuel becomes available, the information that the Agency would need to analyze prior to moving towards utilizing hydrogen as part of determining BSER for existing gas-based units is not readily available today. EPA should focus on building an additional record regarding additional hydrogen co-firing capabilities of the existing fleet, through solicitation of comment an open docket to judge the potential for future emissions reductions once hydrogen is available as a fuel.

Should EPA Solve Challenges on Existing Source BSER For Natural Gas-Based Units, It Should Provide Significant Flexibility in Order to Provide for Continued Emissions Reductions and Reliable, Affordable Power

As discussed in EEI's previous submissions, should EPA move forward with existing source guidelines for natural gas-based units, it should provide significant compliance flexibility to capture the wide variability discussed above regarding the performance characteristics of the fleet. This includes using subcategories to target types and categories of units, the ability to convert rate-based standards into mass-based compliance options, multiple different averaging forms, and the ability to leverage existing state programs, among many other approaches. EPA should adopt options that could allow units to choose among multiple paths to comply with EPA's BSER, helping to facilitate diverse unit owner/operator approaches to complying that also consider customer affordability and grid reliability.