COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION
STATIONARY COMBUSTION TURBINE AND STATIONARY GAS TURBINES NEW SOURCE PERFORMANCE STANDARDS

89 Fed. Reg. 101,306 (December 13, 2024)

Docket ID No. EPA-HQ-OAR-2024-0419

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I. Introduction

The American Public Power Association (APPA or the Association) appreciates the opportunity to provide comments on the proposed rule entitled, "Review of New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines" (Proposed Rule). APPA's members operate power generation plants with combustion turbines (CTs) subject to the Proposed Rule. Therefore, the Association and its members have a strong interest in offering their perspectives on the Environmental Protection Agency's (EPA) proposal for this important electric generation subcategory. To accompany these comments, APPA attaches a technical report by J.E. Cichanowicz and Michael Hein, Hein Analytics, LLC, entitled, "Technical Basis for Comments: New Source Performance Standards for Stationary Combustion Turbines and Gas Turbines" dated April 14, 2025 (the Technical Report).

A. About APPA

APPA is the national trade organization representing the interests of the nation's 2,000 not-for-profit, community-owned electric utilities. Public power utilities are in every state except Hawaii. They collectively serve over 54 million people in 49 states and five U.S. territories, and account for 15 percent of all sales of electric energy (kilowatt-hours) to end-use consumers. APPA and its members are dedicated to clean air in their communities and the protection of the environment. Public power utilities have made significant investments to reduce emissions and comply with the more stringent air regulations that EPA has promulgated over the last ten years.

APPA has thoughtfully engaged in advocacy for sensible regulations for the CT subcategory. Most recently, APPA submitted comments in the federalism consultation for three CT Rules, including this Proposed Rule, the Proposed Reconsideration of National Emissions Standards for Hazardous Air Pollutants: Stationary Combustion Turbines (CT NESHAP), and the Proposed Emissions Guidelines for Greenhouse Gas Emissions from Existing Stationary Combustion Turbines (CT GHG Rule). APPA also filed comments in the docket called, "Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Stationary Combustion Turbines," Docket No. EPA-HQ-OAR-2024-0135.[1] Also, APPA filed three sets of substantive comments in the proposed Greenhouse Gas Clean Air Act (CAA) Section 111 Rule (the Proposed GHG Rule) docket, which applied to the CT subcategory before EPA decided to defer further action on existing CTs.[2]

B. The Important Role of CTs in Sustaining the Grid.

CTs are fundamental energy resources that that support the grid in a variety of ways. Natural gas CTs are the most flexible asset fuel group. Depending on the characteristics of an

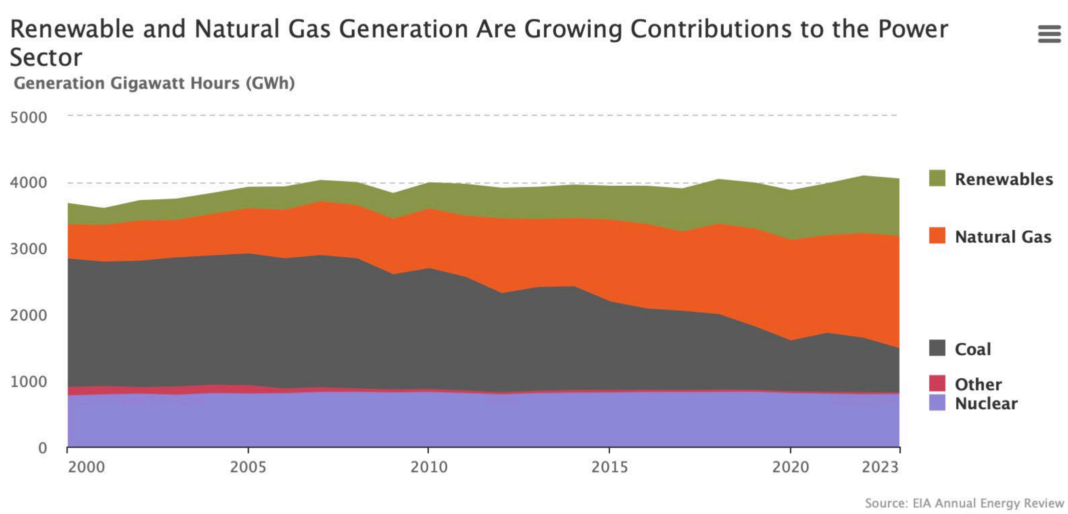
[1] *See* APPA comments at https://downloads.regulations.gov/EPA-HQ-OAR-2022-0723-0016/attachment_1.pdf.
[2] *See* APPA comments at https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0566/attachment_1.pdf (Proposed Rule general comment period); https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0895/attachment_2.pdf (SBAR process); https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-8231/attachment_1.pdf (Small entity comment solicitation).

individual unit, CTs may take on roles as baseload units, peaking units, or even as backup generation during high-load events. CTs are not one-size-fits-all sources because they must swiftly adjust to the fluctuating nature of flexible versus inflexible generation. Grid operators maximize this unique quality of CTs to serve different roles.

First, natural gas CTs may serve as baseload generation. CTs are dispatchable resources. Larger combined cycle CTs offer baseload megawatts that anchor the grid. They are available when grid operators call upon them to serve load. These CTs offer reliability services, acting as capacity resources and providing inertia and voltage support.

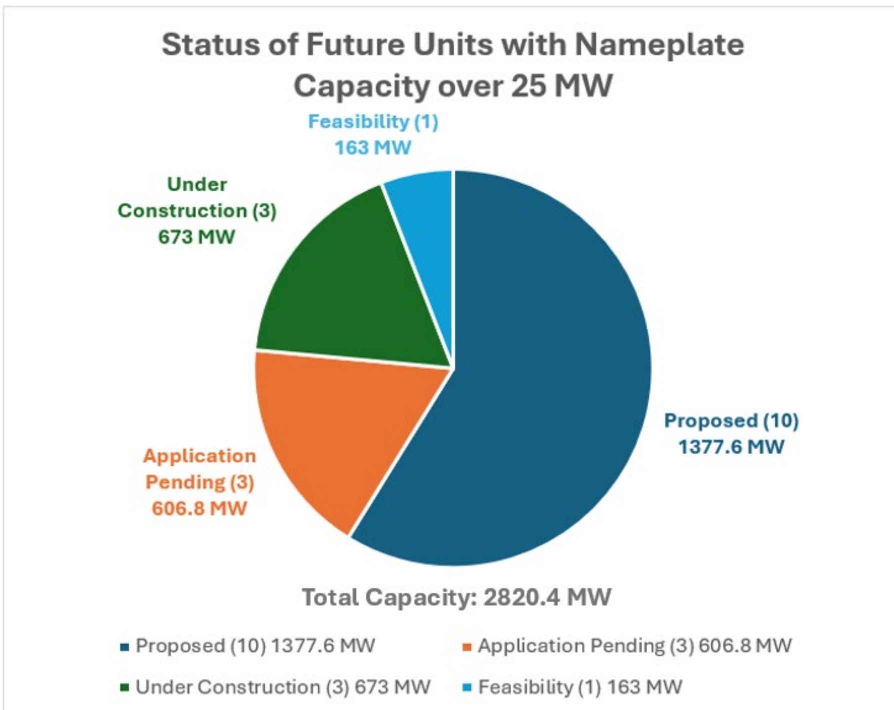
Secondly, CTs support renewable generation resources. Natural gas-fired simple cycle CTs serve as quick-start generation that complements and follows the load of intermittent renewable resources, like wind and solar. These CTs are cycling gas units or units following seasonal or daily patterns (solar or wind). Load-following units are equipped to meet day-to-day variable demand.[3] They offer significant flexibility, ramping up quickly to provide power when renewables are not available and ramping down, as needed. This agility minimizes emissions related to start-up and shutdown, supporting the integration of intermittent renewable resources.

The power sector is undergoing a transition, which further underscores the importance of existing and new natural gas CTs to serve load. The grid is moving toward more generation from lower and non-emitting resources while large quantities of baseload coal generation are coming offline. Since 2000, natural gas generation capacity has increased such that it is the predominant fuel used to support the grid, based on EIA data.[4] In 2023, the largest portion of the natural gas fleet (59%) on a unit basis used combined cycle technology, which accounted for 85% of total natural gas generation [by capacity].[5]



[3] NREL, "The Role of Energy Storage with Renewable Electricity Generation" (January 2010), https://www.nrel.gov/docs/fy10osti/47187.pdf
[4] https://www.epa.gov/power-sector/power-sector-evolution#:~:text=NGCC%20sources%20were%20most%20of,of%20total%20natural%20gas%20generation.
[5] *Id.*

APPA performed an initial review of the new CT capacity anticipated to be built among public power utilities. Data suggests that between 2025 and 2028, approximately 2,820.4 megawatts (MW) of generation is in various stages of development, as illustrated in the chart below and would be subject to the Proposed Rule. To meet the expected load growth from data centers, artificial intelligence, electrification, and onshoring manufacturing, the U.S. is going to need all generation resources. President Trump's Executive Order (EO) 14154 entitled, Unleashing American Energy, seeks to protect the "United States' economic and national security. . .by ensuring that an abundant supply of reliable energy is readily accessible in every State and territory of the Nation."[6]



Given CT generation's vital role, thoughtful regulation of these essential generation assets is important. Emissions standards must be achievable and controls must be cost-effective and proven. APPA appreciates EPA's recognition and consideration of the impacts of regulating CTs on public power utilities as small entities and on grid reliability as a whole.

Public power utilities are responsible for supplying reliable, affordable, and sustainable power to the communities they serve.[7] They are particularly cost sensitive as small entities. As not-for-profit utilities, all the costs of new and existing generation projects are *directly* borne by public power's customers. Therefore, the cost of a selective catalytic reduction (SCR), for

[6] 90 Fed. Reg. 8353, 8353 (Jan. 20, 2025).
[7] American Public Power Association 2024 Statistical Report at 14-15. See https://www.publicpower.org/system/files/documents/2024-Public-Power-Statistical-Report.pdf.

example, must be directly borne by the public power end user. For this reason, APPA advocates for the meaningful consideration of costs on small entity utilities.

C. The Role of New Source Performance Standards (NSPS).

The NSPS provisions of section 111 of the Clean Air Act (CAA) are designed to propose standards of performance that "reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER), taking costs into account that have been "adequately demonstrated" for a category of stationary sources.[8] This part of the CAA ensures that a subcategory, like CTs, are using advanced technologies, focusing on the source and the control of air pollutants subject to the NSPS.

This Proposed Rule should be viewed through the lens of the clean congressional intent of section 111. The NSPS program does not focus on ambient air quality levels, nor does it consider the health or impacts of new projects. Other CAA programs have features targeted at these air impacts, such as the National Ambient Air Quality Standards (NAAQS) and the Prevention of Significant Deterioration (PSD) programs. Therefore, it is important to view this Proposed Rule in the context of its technology-focused goals.

Notably, EPA issued this rule as part of the eight-year review of NSPS. The agency can retain standards or review and if appropriate, revise them. In conducting this review, EPA considers if the standards reflect the degree of limitation achievable through application of the BSER. EPA considers statutory factors and other information, such as the recent growth of the subcategory, advances in pollution controls, other systems of emission reductions, cost updates, and other updates.[9] This inquiry further demonstrates the review's narrow focus on the BSER technology capabilities at hand and the advances that have occurred in the last eight years. EPA must adhere to this statutory context and purpose rather than overstate developments in SCR technology and/or other generalized NOx or co-benefit reduction needs.[10]

APPA has reviewed and analyzed the Proposed Rule and urges EPA to consider the following points that are discussed in more detail below:

- Exemptions for emergency CTs should be maintained, as proposed by EPA;
- Exemptions for certain low-emitting, non-major source CTs from Title V permitting requirements under CAA section 502(a) should be permitted;
- The definition of "stationary source" should not be narrowed for the purposes of new source or reconstructed source analyses;
- EPA's chosen subcategorization by size, the medium and large CTs is appropriate; however, further subcategorization by operational duties, exhaust temperature characteristics, and the function of natural gas-fired CT is more appropriate;
- EPA's reference turbine is not representative and should be revised not artificially lower control technology cost projections;

[8] CAA § 111(a)(1),(3).
[9] 89 Fed. Reg. at 101312.
[10] EPA claims that since 2006, "[I]t has become clear that SCR technology is widely available and frequently adopted. . .. " 89 Fed. Reg. at 101315.

- The Proposed Rule should not regulate fuel oil and natural gas combusted at the same time;
- Hydrogen co-firing is too nascent to support a standard with such limited data;
- Alternative mass limits are unlawful due to the capacity factor restrictions that would result;
- Low load operation is essential and not incentivized; therefore, low load, non-SCR operation should be allowed to support grid flexibility;
- The proposed exclusion for combustion control technologies with SCR should be implemented;
- Emissions limits for baseload units should not be set at 2 or 3 parts per million (ppm), and a longer emissions averaging period is necessary (e.g., 30-day rolling average). A compliance margin is needed, and consideration of the emissions profiles of different types of CTs is important;
- Startup, shutdown, and fuel transition periods should be excluded from the emissions average for compliance; and
- SCR costs should be recalculated to reflect the current market and use a typically sized CT.

In addition to these items, APPA supports swift action to revise the Proposed Rule. It is actively affecting new generation projects by imposing unsubstantiated NOx requirements and injecting uncertainty into the permitting process for new CTs. To address APPA's concerns, APPA respectfully requests a finding that reaffirms the requirements of Subpart KKKK and permits EPA additional time to examine further whether revisions to the current standard are even required, as determined in the Administrator's discretion.

II. Applicability Issues Raised by the Proposed Rule.

A. Exemptions for Certain Stationary CTs Should Be Maintained.

EPA proposes to exempt emergency CTs from the NOx limits in the Proposed Rule. This position would continue to exempt these units, consistent with Subpart GG and Subpart KKKK.[11] Emergency CTs offer quick, reliable power during emergency circumstances in the event primary systems fail. Weather events are causing more unanticipated circumstances that have destabilized the grid. Emergency CTs help to maintain, restart, or restore electrical service as quickly as possible. The increased risk of emergencies justifies exempting these units so they can respond without regulatory shackles. APPA supports EPA's position to exempt emergency CTs.

EPA is also seeking comment on whether there are additional source categories of facilities with stationary CTs that are subject to the more stringent NSPS that should not be subject to the sulfur dioxide (SO_2) and or nitrogen oxide (NOx) standards in Subpart GG, KKKK, and the proposed KKKKa.[12] APPA supports an exemption for low-emitting, non-major source CTs from Title V permitting requirements, which EPA may promulgate under CAA section 502(a). Under this provision, EPA may exempt certain sources subject to CAA section

[11] 89 Fed. Reg. at 101313.
[12] *Id.*

111 (NSPS) or section 112 requirements from Title V permitting requirements if the agency finds that compliance with such requirements is "impracticable, infeasible or unnecessarily burdensome on such categories except that the Administrator may not exempt any major source from such requirements." Compliance with Subpart KKKKa would be unduly burdensome due to the cost of installing controls or otherwise complying with emissions limitations as BSER that are not achievable for all units in the subcategory. Considering the requirements of the respective NSPS standards, APPA believes that subjecting these low-emitting CTs to Title V permitting would not result in any significant regulatory benefit.

B. The New or Reconstructed Unit Test Should Use the Definition of "Stationary Source" as Is Used for Modified Units.

The Proposed Rule seeks to narrow the application of the critical definition of "stationary source" used in the analysis to determine if an existing CT is "new" or "reconstructed." The components of equipment considered the "stationary source" are pulled into the "affected source" in 40 CFR § 60.2. The "affected source" is the key term used in the reconstruction and the new source analyses. The proposed Subpart KKKKa definition of stationary source includes the heat recovery steam generators (HRSG), duct burners, and other ancillary equipment, consistent with the definition in Subpart KKKK.

By narrowing "stationary source" only for these two purposes, EPA acknowledges the result – the entire replacement of the CT portion of the affected facility would be a new source. Similarly, reconstruction would be based on replacement of components of the CT engine portion only, which is a smaller cost as compared to all of equipment in the definition of "stationary combustion turbine."[13] EPA's goal is clear, to require CT owners to "invest in emissions control equipment" when the CT engine is replaced.[14] In contrast, to determine whether a CT is modified, the entire "stationary combustion turbine" must be considered.

EPA's approach to "new" and "reconstructed" units should be abandoned for a myriad of reasons. First, applying different stationary source definitions creates regulatory disharmony with the general NSPS provisions that apply to all section 111 standards, calling the legality of EPA's Subpart KKKKa approach into question. The general NSPS framework uses the definition of "affected facility"[15] in 40 CFR § 60.2 and applies it to the "stationary source" in each NSPS subcategory. In other words, the general NSPS provisions are designed to consider the definition of the stationary source in Subpart KKKKa. However, in the Proposed Rule, EPA departs from

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[13] EPA defines "*Stationary combustion turbine" as* "all equipment including, but not limited to, the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except post combustion emissions control equipment), heat recovery system (including heat recovery steam generators and duct burners); steam turbine; fuel compressor, heater, and/or pump, post-combustion emission control technology, any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system; plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine (*e.g*., onsite photovoltaics), integrated energy storage (*e.g*., onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability." Proposed 40 CFR Part 60 Subpart KKKKa.

[14] 89 Fed. Reg. 101306, 101314 (Dec. 13, 2024).

[15] *Affected facility* means, with reference to a stationary source, any apparatus to which a standard is applicable. 40 CFR § 60.2.

this approach by going outside the stationary source definition and using an alternative provision. That alternate provision states, "When determining if a facility is new or reconstructed, do not include the equipment associated with the HRSG, as included in the definition of a stationary combustion turbine."[16] This provision departs from the NSPS architecture and should not be allowed.

Second, the determination of whether a unit is "modified"[17] *does not use* EPA's engine-only approach. It appears that EPA is picking and choosing between definitions rather than applying a uniform stationary source application to analyses for new, modified, and reconstructed units. The NSPS regulations do not account for this selective parsing.

Third, APPA is not aware of any regulatory precedent for EPA's approach to adopt a definition of stationary source but declines to apply it for all purposes. A long line of Part 60 applicability determinations utilize the stationary source definition for the Subpart in question as the comparison point against the equipment replaced or substituted as part of the project.[18] The Proposed Rule departs from almost 50 years of NSPS application. In addition, EPA offers absolutely no justification for this departure other than the expanded definition of affected facility in Subpart KKKK was not intended to change these determinations. However, the Proposed Rule does not offer any regulatory citation to justify its claims about Subpart KKKK or to support this policy change.[19]

Finally, using an engine-only analysis would disincentivize beneficial projects to maintain the CTs. With a huge price tag of a SCR in the balance, CT owners would be more conservative in the types of projects they decide to perform to avoid any potential of triggering Subpart KKKKa. For instance, if too much money is spent to overhaul an engine, reconstruction is triggered. Owners would be encouraged to keep maintenance minimal. In addition, owners may keep spare engines or their parts on-site to install if part of an engine needs to be shipped offsite for manufacturer recommended equipment maintenance or unexpected repairs. This maintenance strategy avoids unit downtime, sustaining the grid. But it would now be a concern that the owner is synthetically creating a "new unit" by pursuing temporary maintenance changeouts. In either case, the outcome would result in needless requirements that reduce grid reliability.

EPA should use the stationary source definition in Subpart KKKK for *all purposes* in Subpart KKKKa or any successor NSPSs for CTs. There should be no change in the "stationary source" definition.

C. Subcategorization Is an Appropriate Framework to Regulate CTs.

APPA supports subcategorization of the CT source category. Technical study of the universe of CTs generally supports EPA's categorization approach as an accurate

[16] Proposed 40 CFR § 60.4305a.
[17] "Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere." 40 CFR § 60.14.
[18] EPA ADI, Control 0900067 (the Centerpoint ADI); EPA ADI Control 0300105 (the Alyeska ADI).
[19] 89 Fed. Reg. at 101314.

characterization of the gas turbine fleet for the medium and large CT categories.[20] Most aeroderivative units range from 50-75 MW in capacity. However, EPA does not distinguish between the three main classes of units: E-class, F-class, and the largest H-class units, which all have substantially different NOx emissions performance without SCR and simple cycle verse combined cycle.[21]

EPA proposes three size-based subcategories for CTs that commence construction, modification, or reconstruction after December 13, 2024. The subcategories are based on the "rating of the turbine engine and do not include any supplemental fuel input to the heat recovery system." EPA refers to these categories as small, medium, and large CTs.[22] Then, EPA further subcategorizes these CTs as low (less than or equal to 20%), intermediate (greater than 20% to less than or equal to 40%) and base load (greater than 40%) units, depending on 12-calendar-month capacity factors.[23]

Aeroderivative turbines have lower exhaust temperatures (approximately 200°C lower) than frame-type turbines, making them more suitable for conventional SCR systems for NOx reduction. However, the higher temperatures from frame-type units require additional cooling costs that EPA appears not to have included in its BSER analysis.

It may be more appropriate to develop a regulatory framework for new natural gas-fired CTs based on compatibility with the operational duties, exhaust temperature characteristics, and the CT's function. CAA section 111(b)(2) provides EPA with the broad authority to "distinguish among classes, types, and sizes" of sources to establish appropriate subcategories subject to the NSPS.[24]

III. Technical Issues Raised by the Proposed Rule.

A. Gas Turbine Assumptions

EPA makes assumptions about the CT fleet that shape the Proposed Rule. While APPA supports EPA's categorization of medium and large turbines, as stated *supra*, other assumptions in the Proposed Rule are problematic.

EPA's Reference Turbine. Of significant concern is that EPA's reference turbine is not representative of the fleet of simple cycle and combined cycle units. The agency selected a 459 MW CT. That CT is larger than 99.7 percent of the fleet. The selection of an atypically large CT results in lower SCR cost projections by EPA that are not accurate , as discussed below. EPA should reevaluate the size distribution of units to identify a more representative unit.

Co-firing with Fuel Oil. Most combustion turbines do not fire fuel oil and natural gas contemporaneously. Energy Information Administration (EIA) data shows that only 177 units

[20] Technical Report at Sec. 2 at 6.
[21] *Id*.
[22] 89 Fed. Reg. at 101316.
[23] *Id*.
[24] 42 U.S.C. §7411(b)(B)(2).

out of the population of approximately 2,500 can contemporaneously fire alternative fuels.[25] Those fuels appear to be mostly synthetic or renewable gases. Of these capable units, fuel oil and gas are not fired at the same time because state-of-the-art dry low NOx combustors are not able to manage the injection, mixing, and volatilization of liquid fuel while minimizing NOx and particulate matter. Instead, fuel oil is used for startup or as an alternative fuel should natural gas be curtailed. EPA should factor this into its analysis and decline regulating co-firing because it is unnecessary based on current equipment capabilities and usage.

Co-firing with Hydrogen. EPA proposes a new category for CTs that burn hydrogen as natural gas or non-natural gas sources. The agency then assigns NOx rates to these CTs.[26] APPA does not support a hydrogen category because there is not adequate support for it based on industry data. There is such limited commercial experience with hydrogen utilization that EPA does not have sufficient information to set or to mandate specific NOx limits. Due to the lack of publicly available data and the short-term nature of combustion data that does exist (no more than several days), EPA cannot confidently identify an achievable NOx emission rate for these units. APPA does not support a category or NOx limit for these sources currently.

In summary, APPA supports NSPS standards based on the type of fuel burned in a CT-engine only. This change should apply after December 13, 2024.

B. Alternative Mass-Based NOx Limits Would Compromise Grid Reliability.

EPA seeks comment on the concept of reverting to a 12-calendar month NOx emissions limit in lieu of subcategorizing CTs based on capacity factor.[27] This approach fails. These proposed output-based mass limits would impose strict operating barriers on commercial units, and the limits would interfere with the ability of CTs to deliver power and balance to the grid.

The Technical Report reviewed the implications of imposing a mass-based limit on CTs.[28] It finds that CTs would be capped at restrictive capacity factors using three mass limit cases that EPA proposes – a .21 ton mass limit, a .45 ton mass limit, and a .75 ton mass limit. The following tables assume SCR technology will operate at high loads but not at lower loads. The tables also assume a part load rate of 50 ppm for illustrative purposes only. For comparison, the Subpart KKKK part load limit is 96 ppm.

[25] *Id.* at Sec. 2 at 6.
[26] 89 Fed. Reg. at 101338.
[27] 89 Fed. Reg. at 101346-47.
[28] Technical Report at Sec. 3 at 9.

***Case 1: .21 Ton Mass Limit*, *50 ppm Part Load NOx Rate* Illustration of Capacity Factor Restrictions E*ven for SCR-Equipped CTs*[29]**

CT High Load Percentage	Proposed Mass Limit in Tons /MW /Calendar Year	Assumed NOx Emissions in ppm	Resulting Capacity Factor Load Based on the Mass Limit
95%	.21 tons	3 ppm	26%
70%	.21 tons	15 ppm	5%

These results show that even with state-of-the-art technology, a low-emitting unit performing at 3 ppm could not run at full capacity. This outcome is counter to the legal basis of CAA section 111. A source-specific limitation should be achievable without curtailing operation. Otherwise, the emission limitation would not be tailored to the BSER. Indeed, even when operating an SCR (BSER), further measures are required to reduce emissions to beyond a BSER level. There is no legal or technical justification that would allow EPA to promulgate this mismatch.

***Case 2: .45 Ton Mass Limit*, *50 ppm Part Load NOx Rate*[30]**
Illustration of Capacity Factor Restrictions *Even for SCR-Equipped CTs*

CT High Load Percentage	Proposed Mass Limit in Tons /MW /Calendar Year	Assumed NOx Emissions in ppm	Resulting Capacity Factor Load Based on the Mass Limit
95%	.45 tons	3 ppm	56%
70%	.45 tons	15 ppm	11%

Even with a slightly more generous NOx mass limit (.45 ton), capacity factors are still substantially reduced. The 3 ppm SCR unit would see a reduction of almost half of its value. Additional emissions scenarios and the resulting capacity factor restrictions further support this point are illustrated in the Technical Report. Even with a more generous mass limit of .75 tons, capacity factors are still limited, especially at load ranges of 13-58 percent.

Aside from the legality of these capacity factor limitations, grid reliability would be compromised. Cumulatively, these limitations would cause a substantial loss of capacity on the grid. CTs serve a crucial stabilizing role for renewables and offer dispatchable energy. If owners can no longer realize the full potential of CTs, it would be more likely that increased energy demands cannot be met.[31] For all these reasons, APPA urges EPA to depart from a NOx mass limitation for CTs.

[29] Technical Report at Table 3-2.
[30] *Id.*
[31] NERC, 2024-2025 Winter Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_Infographic_2024.pdf ("Rapid demand growth in many areas is further straining parts of the system. While demand has grown, over 4.5 GW of generation has been retired over the same period in the United States increasing reliability risk.").

C. Preserving Low Load CT Operation Is Essential to Grid Reliability.

EPA solicits comment on the part load standard and, specifically, whether there is a regulatory incentive to operate at reduced loads to avoid SCR operation.[32] Study of CT behavior and NOx emissions at part load confirms that EPA's concern is unfounded. CT owners would not realize any net financial gain. In fact, when comparing the revenue for a SCR-equipped unit with a unit intentionally limiting operations at part load to avoid SCR operation, the SCR-equipped unit generates higher revenue by approximately $0.80 million.[33] No financial incentive exists to purposely run at part loads to avoid SCR operation. EPA should dismiss this hypothetical concern.

Regardless, many other factors affect CT operation including whether or how long the CTs operate at part loads. Further study of CT behavior reveals that turbine operating time at less than 70 percent load is driven by the need to "balance" the grid and offset the effect of non-dispatchable assets.[34] Part load is rarely intentionally selected by the operator. In fact, restricting CT operations artificially would have dire consequences because it would constrain normal operation of certain CTs with gap-filling roles at lower loads. For example, the population mid-point of medium and large combined cycle turbines expends only 25 percent and 20 percent of their time at part load, respectively. Similarly, medium and large simple cycle units show similar trends. Large simple cycle units operate 66 percent of their operating time at high load (more than 70 percent), while medium simple cycle units spend 57 percent of their operating time at high load, using the population midpoint.[35]

If EPA restricts operation, the lack of flexibility could compromise options to balance grid reliability. A grid operator has the challenge of continuously matching the demand for electricity with supply on a second-by-second basis. To achieve this task, the operator may need to change ramp directions quickly; react quickly and meet expected operating levels; start assets with short notice from a zero or low-electricity operating level; or start and stop multiple times per day. Hampering the capabilities of hundreds of CTs would severely handicaps operators. APPA strongly opposes any constraint on the low-load capabilities of these units.

EPA also asks for comment on the effectiveness of combustion control technology in conjunction with SCR during part load conditions. [36] The agency also asks whether these technologies lose "all value" at part load operation.

The performance of combustion control technologies is often reduced for units operating under part-load conditions, as it takes time for the operating temperature to reach the levels necessary for the SCR system to reduce NOx emissions effectively. Additionally, when the SCR system is offline for maintenance, the turbine may need to operate at reduced loads. For these

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[32] 89 Fed. Reg. at 101320.
[33] Technical Report at Sec. 4 at 14.
[34] *Id.*
[35] *Id.* at Figure 4-4 and 4-5 (providing the full range of CT load ranges for simple and combined cycle units).
[36] 89 Fed. Reg. at 101320.

reasons, EPA should implement the proposed exclusion for combustion control technologies in conjunction with SCR when units are operating under part load conditions.[37]

Furthermore, EPA should adopt the proposed definition of part load in Subpart KKKKa as operating at 70 percent or less of the base load rating, which aligns closely with the load rating at which CTs can maintain steady-state emission rates after startup. Additionally, other control technologies, such as water/steam injection or dry-low NOx burners, may not be as effective during startup due to the lower combustion temperatures.

SCR reactors are designed to provide a uniform gas velocity, temperature, and composition when the flue gas enters the catalyst, typically during base load and steady-state operations. Variances in load and the rate of change create limitations in SCR performance, increase the complexity of hardware designs, and, in some instances, render the installation of an SCR impractical. The following are part-load conditions that may compromise the SCR design and operation:

- High NOx in the flue gas will vary during the transition from different burner operating modes;
- Gas temperatures below 580 degrees Fahrenheit create minimal reaction time for NOx removal; and
- Ammonia mixing in the gas stream and penetration of NH3 and NOx into the catalysis is impacted by low-velocity gas flows.[38]

Part load conditions can lead to ammonia slip exceeding 10 ppm, up to 20 ppm. Therefore, NOx emissions less than 5 ppm would be challenging to achieve, placing units at risk of exceeding the proposed emissions limit.

D. Emissions Limitations for CTs with SCR at High Load Must Be Achievable.

EPA solicited comments on a range of potential emissions limitations for intermediate and base load units when firing natural gas and using SCR technology. EPA's range of consideration is 2 to 5 ppm.[39] The agency proposes 3 ppm as a level capable of being achieved regardless of turbine type. The attached Technical Report evaluated 2023 hourly CEMS data from EPA's 11 reference units, six simple cycle and five combined cycle units to examine achievability and attempted to replicate EPA's analysis.[40] The Report applied a four-hour rolling average calculation using these data to compare the actual emissions rates against a range of 2 ppm to 4 ppm.

The results of the analysis are:

[37] Technical Report at Sec. 6 at 26-27.
[38] *Id.*
[39] 89 Fed. Reg. at 101325.
[40] Technical Report at Sec. 5 at 20.

- Two ppm is rarely achieved 100 percent of the time, even for combined cycle units, as concluded by EPA *and* the Technical Report findings. Only three of the 11 units were successful;
- Three ppm is more achievable, but five of 11 (mainly combined cycle units) could achieve 3 ppm 100 percent of the time. EPA's data and the Technical Report findings show a very narrow compliance margin, particularly for simple cycle units;

If EPA maintains SCR as the required technology for certain categories, the standard should be established above 3 ppm to ensure feasible compliance across diverse operational conditions, especially simple cycle units.

Looking beyond the above conclusions, the technical experts were not able to replicate EPA's emissions analysis. Since EPA's methodology was not revealed, there is concern because it was not possible to vet all the assumptions used and to fully understand the agency's analysis. Therefore, APPA requests additional information regarding the basis for EPA's calculations.

Finally, APPA notes that the four-hour averaging period compounds compliance challenges. If EPA extended the averaging period to 30 days, compliance statistics would improve.

In addition, startup, shutdown, and fuel transition periods, as well as CEMS outages/maintenance hours and partial hours, should be excluded from the averaging period when determining compliance. The SCR does not operate to its full capacity during these times and including those hours would result in data that does not reflect actual emissions. Excluding these periods would also correspond with existing permits, minimizing the additional monitoring data that needs to be collected. CT operators need compliance flexibility during these periods of variable operation, particularly as grid operators call on CTs to start and stop more often to sustain reliable power and grid support. Furthermore, EPA's reliance on *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008)[41] to include startup and shutdown emissions is misplaced. EPA extends the court's reasoning in section 112 to section 111 of the CAA. However, these sections of the CAA are structured differently and regulate entirely different types of air pollutants (hazardous versus criteria pollutants). As the U.S. Supreme Court recognized in *UARG v. EPA,* 573 U.S. 302 (2014), different CAA programs may warrant different regulatory approaches.[42] EPA also failed to explain sufficiently why *Sierra Club* should be applied to a section 111 standard. It only offers a conclusory remark that the two sections use the same definitions for "emission standard" and "the embedded requirement for continuous standards." However, common definitions do not overcome the large differences between section 111 and section 112. EPA's failure to adequately explain its reasoning for including startup and shutdown emissions for Subpart KKKKa standards is arbitrary and capricious.

[41] 89 Fed. Reg. at 101347.

[42] *UARG*, 573 U.S. at 318-19 (*Massachusetts* did not hold that "EPA must always regulate greenhouse gases as an 'air pollutant' everywhere the term appears in the statute" but "EPA 'may consider' regulating under CAA operative provisions.").

Finally, units already permitted by a local air district with more stringent limits should be exempted from these regulations to prevent an additional regulatory burden without a corresponding reduction in emissions.

E. EPA's SCR Cost Evaluation Is Artificially Low.

EPA should revise its SCR cost evaluation to consider the reasonable costs to install an SCR on a typical CT. The agency found that SCR technology has "reasonable costs" for CTs of all sizes.[43] However, this analysis contains multiple flaws that impact the result. The issues are:

- EPA's contractor B&V acknowledged that the SCR capital costs in its study do not reflect present market pressures experienced by operating plants today or "the price consumers can expect to pay." This disclaimer calls the entire analysis into question.
- Simple cycle budgetary quotes exceed EPA's SCR cost analyses.[44] The Technical Report provides five SCR quotes that exceed the estimates in EPA's cost estimates.
- EPA selected a base reference case that is the largest gas turbine in the inventory at 4,450 MBtu/h and generating 456 MW. The reference unit capacity and capacity factor used by EPA is atypical (in 99th percentile), resulting in an error by artificially lowing the cost per ton. This error must be corrected.

As the Technical Report states, EPA should use a more representative reference unit of 2,000 MBtu/h (205 MW), which is more typical of the size of most CTs. This more representative unit capacity increases the combined cycle SCR cost from $9 to $12/kW, and the simple cycle SCR cost from $15 to $28/kW. In addition, the capacity factor should be adjusted lower to reflect demand in areas of high renewable penetration, where the highest levelized cost of control will be observed. EPA's capacity factors for intermediate load should be reduced from 30 percent to 20 percent and for "high" duty from 60 percent to 40 percent. If the agency makes these adjustments to use a representative unit plus a lower, more appropriate capacity factor, the estimates of cost per ton for scenarios projected by EPA increase capital costs of an SCR from $50,000 per ton to over $500,000 per ton.[45] In summary, EPA's estimate of the SCR capital cost for simple cycle units, and the incurred cost per ton of NOx for both simple and combined cycle units, is low and should be adjusted.

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Thank you for considering these comments. We look forward to working with the agency as it develops this rulemaking. Should you have any questions regarding these comments, please contact Ms. Carolyn Slaughter (202-467-2900) or cslaughter@publicpower.org

[43] 89 Fed. Reg. at 101329.
[44] *See, e.g.,* Jack County SCR cost as installed ($25/kW) exceeds the value per EPA projection ($8/kW for similar combined cycle capacity), EPA-HQ-OAR-2024-0419-0017_attchment_1; TVA estimates that F-Series gas turbines (>>$100/kW) also exceed the EPA estimate for similar 88MW unit (~$50/kW).
[45] Technical Report at Sec. 7 at 38.

ATTACHMENT 1

Technical Basis for Comments:
New Source Performance Standards
for Stationary Combustion Turbines and Gas Turbines

Prepared for:

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April 14, 2025

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i. Summary

This report provides comments on aspects of the Environmental Protection Agency (EPA) December 13, 2024 proposed revision to New Source Performance Standards (NSPS) for nitrogen oxides (NOx) emissions for new combustion turbines, as well as such turbines that are "modified" or "reconstructed".

Comments are presented according to seven categories. The first category concerns the existing combustion turbine population. Our analysis finds that EPA's construction of the combustion turbine population database reflects units devoted to utility power generation in one respect. Units with heat throughput less than 250 million British thermal units per hour (250 MMBtu/h), or approximately 25 megawatts (MW) of output are not addressed in this report, as few are deployed for utility power generation. A large number of combustion turbines, reflecting the aeroderivative category, with heat throughput between 250 and 850 MMBtu/h do provide utility power generation. Units greater than 850 MMBtu/h are typically designated as frame turbines and are also a major contributor to present and likely future utility duty. EPA does not, however, recognize important difference between four major classes of frame turbines, each of which can generate NOx emission ranging from 25 ppm to (for some cases) as low as 5 ppm. Regarding solicited comments on NOx emissions for "co-firing" of natural gas with alternative fuels, the U.S. Energy Information Administration (EIA) reports indicate few units contemporaneously fire fuel oil and natural gas; fuel oil although used, is mostly directed for startup or as an occasional backup fuel. Regarding co-firing of hydrogen, numerous short-term demonstration tests have been conducted on combustion turbines but NOx emissions data either on a concentration basis or mass rate are not publicly available. Consequently, any attempt to establish a NOx emission standard for hydrogen firing (and co-firing) is premature.

A second category is EPA's proposal for an alternative mass-based output limit of NOx emissions, in terms of tons emitted per MW of generating capacity, over a calendar year. EPA proposed a range of mass emission rates– from 0.25 to 0.75 tons per MW per calendar year – but even the highest rate constrains operation, essentially severely limiting utilization of the power generating asset. Depending on the assumed NOx emissions rate at part load (less than 70% of rated capacity[1]) and high load (greater than 70% rated capacity), a mass-based output limit can in many cases restrict annual capacity factor to less than 20%. Such a constraint prevents combustion turbines from operating as needed to balance the non-dispatchable resources in the grid and improve electric reliability.

A third category addresses EPA's concern that owners will intentionally operate combustion turbines at part load to avoid investment to meet high load NOx limits. There is no economic

[1] This discussion presumes the "rated capacity" of a combustion turbine is the nameplate generation for ISO conditions of 15°C (59°F), 101.325 kPa (14.7 psia), and 60% relative humidity. In terms of heat input, the rule refers to the turbine's capacity as "base load rating."

incentive to do so – in fact, such actions incur a cost penalty. Limiting duty to part load – essentially forgoing all revenue for duty at greater than 70% of capacity for the lifetime of the unit - significantly restricts revenue and provides only minor cost savings. In the present market, high load duty is required for both medium and large combustion turbines. Units at the population mid-point expend 75-80% of operating time at high load. Thus, any means to limit operation interferes with actions to balance the generating grid.

A fourth category is the achievability of proposed high load NOx emission rates of 2 and 3 parts per million (ppm), feasible only by deploying selective catalytic reduction (SCR) NOx control.[2] First, the calculations supporting EPA's conclusions as to the feasibility of compliance for 2, 3, and 4 ppm limits could not be replicated for all cases by this study. The results are disparate – several cases of "100%" compliance are replicated, but for a number of cases this study reports a lower frequency of compliance. There are also cases where this analysis predicts a higher frequency of compliance than EPA. Regardless, both analyses show a significant shortfall in compliance frequency for the 2 ppm standard, as less than half of cases are successful. Compliance frequency is higher with a 3 ppm limit but the margin is small. These results suggest uncertainty in meeting even the 3 ppm standard while abiding by acceptable levels of residual ammonia (NH_3).

A fifth category describes the challenge of designing and operating SCR process equipment for part load duty. SCR technology has evolved to be reliable and effective but critically contingent upon providing proper process conditions at the catalyst inlet. These process conditions include a uniform distribution of gas flow velocity, high (but generally not exceeding 850 degrees Fahrenheit, ºF) gas temperature to prompt catalyst activity, and most important a uniform distribution of ammonia reagent and NOx (e.g. NH_3/NOx ratio). Achieving high NOx removal (~75% or more) requires a uniform distribution of NH_3/NOx ratio at the inlet of catalyst. At part load duty, a combustion turbine at the exit presents tortuous gas flow conditions, particularly high and variable velocity, NOx content, and temperature – conditions not conducive to uniform NH_3 and NOx. These part load conditions compromise NOx control unless high exhaust gas content of residual NH_3 is accepted.

The sixth category addresses EPA's cost evaluation to determine the levelized cost per ton of NOx removal. The EPA bases its analysis on SCR capital cost from a Department of Energy National Energy Technology Laboratory (NETL) study.[3] There are several flaws in EPA's approach. First, EPA uses in the analysis a reference unit likely not representative of future installations, and a capacity factor that does not reveal the highest cost possible. Second, the SCR capital cost for combustion turbines in simple and combined cycle duty is dated, and – as conceded with a disclaimer in the NETL reference – may not reflect present market forces. Recent SCR quotes and installations confirm it does not. Third, EPA ignores the widely divergent NOx emission from four key categories of combustion turbines – aeroderivative, E-Class, F-Class, and H-Class and similar very large turbine models. NOx emission from these

[2] EPA cites these target NOx rates assuming a content of residual ammonia in the gas of 10 ppm, at catalyst end-of-life.
[3] Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, NETL Report DOE/NETL-2023/3855, May 5, 2023. Hereafter NETL 2023 Cost Study.

different combustion turbine categories, using advanced combustion controls, can vary from 25 ppm to 5 ppm, significantly affecting the estimated cost per ton to control NOx.

Analysis in this report addresses EPA's shortcomings. The analysis first replicates EPA's cost methodology using a "generic" reference unit, but of lower heat throughput (2,000 MMBtu/h) and capacity factors for three categories: *low* (less than 20%), *intermediate* (20% is used in the analysis, which is the low end of the 20% to 40% range), and *base* (40% is used in the analysis, which is the low end of the greater than 40% range for base load duty). The lower heat throughput better reflects new combustion turbines likely to be installed. The revised capacity factors represent the lowest of the *intermediate* and *base* categories, reflecting the highest cost in these ranges. In addition, the evaluation considered combustion turbine exit NOx emissions over a range from 25 ppm to as low as 5 ppm, reflecting capabilities of the various classes of frame turbines. Revising this analysis to consider changes results in the levelized cost per ton to be higher than EPA's by a minimum of 50-100%; for some cases with 9 ppm and 5 ppm emissions rate, the cost per ton exceeded $25,000.

Further evaluation considered updated SCR capital cost, as experienced by several owners of simple cycle combustion turbines. These owners solicited bids for SCR process equipment, the cost for which per unit generating capacity exceed EPA's by a factor of 2 or 3. These elevated costs apply to new units, with much higher costs estimates received for retrofit to existing units. These adjustments of capital cost and NOx emissions, the latter considering between 25 ppm and 5 ppm, reveal levelized cost per ton exceeding $50,000 and for some cases several hundred thousand dollars. Consequently, this study shows EPA's methodology under-estimates both SCR capital cost and the levelized cost per ton of NOx removed.

The seventh category addresses EPA's request to identify changes to gas turbines, other than combustor upgrade or rebuild, that could potentially increase throughput. This section advises that either a compressor upgrade or the use of high volume air vanes can increase air flow. These actions if deployed contemporaneously with a combustor upgrade or a hot gas path upgrade are part of work that lowers NOx and potentially sulfur dioxide (SO_2) emissions.

SECTION 1. INTRODUCTION

The Environmental Protection Agency (EPA) on December 13, 2024, proposed amendments to the new source performance standards (NSPS) for NOx emissions from new, modified, and reconstructed stationary combustion turbines and stationary gas turbines.[4] The EPA proposed updating the requirements of Subpart KKKK for a wide variety of combustion turbines, including those used for electric power generation. Most notably, EPA has focused on altering the NOx emission standard assigned for "high-load" and "part-load" duty, as well as the threshold by which these load segments are distinguished.

The use of combustion turbines for power generation has increased significantly in recent years.[5] The combustion turbines for new application will look very different from those previously deployed. Specifically, the design of turbine components and the combustor will be capable of frequent and rapid load changes, as necessary to balance the generation grid as non-emitting resources either become available or lose delivery capability. Despite significant research and development (R&D) efforts by turbine suppliers, controlling nitrogen oxides (NOx) at extremely low loads remains very challenging.

Each of the major gas turbine suppliers has significantly evolved their technology in recent years. Most notable is the evolution of combustor technology to meet NOx limits without water injection. Design challenges persist at low load, as creating the ideal conditions for fuel and air mixing, fuel utilization, and flame temperature to limit NOx is very difficult to achieve at low load.

Combustor design is also evolving to fire hydrogen, either exclusively or in a blend with natural gas. Each of the suppliers has made progress in doing so, although as summarized in recent reviews, the commercial experience is limited to short term tests or the use of refinery off-gas, the latter not exclusively hydrogen.[6,7]

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[4] 89 Fed. Reg. 101306 (December 13, 2025) (Proposal).

[5] Gas Turbine Market Forecast, March 21, 2024. See https://gasturbineworld.com/market-forecast/

[6] Emerson, B. et. al., Assessment of Current Capabilities and Near-Tem Availability of Hydrogen-Fired Gas Turbines Considering a Low Carbon Future, Proceedings of the ASME Turbo Expo 2020: Turbomachinery Technical Conference and Exposition GT 2020, June 22-26, 2020, London, England.

[7] Comments of the Electric Power Research Institute on Environmental Protection Agency EPA-HG-OAR-2014-0128; FRL-5788-02-OAR, Review of New Source Performance standards (NSS) for Stationary Combustion Turbines and Stationary Gas Turbines - Proposed Rule, March 13, 2025.

This report is organized into seven sections. After this Introduction, the database used by EPA to distinguish between turbine categories and fuel use is reviewed in Section 2. Section 3 addresses EPA's proposed alternative mass-based output limit. Section 4 addresses part load duty. Section 5 reviews the achievability of meeting NOx limits of 2 and 3 parts per million (ppm) that require the use of selective catalytic reduction (SCR). Section 6 reviews the design steps required to deploy SCR over a broad load range, including startup and part load. Section 7 critiques EPA's cost evaluation, and Section 8 identifies an upgrade to combustion turbine equipment that when deployed with a combustor or hot gas path upgrade, can be part of work that lowers NOx and potentially sulfur dioxide SO_2 emissions.

SECTION 2. DATABASE OF GENERATING ASSETS AND FUEL CAPABILITY

The EPA categorizes the population of combustion turbines based on heat throughput reported to the U.S. Energy Information Administration (EIA).[8] The EPA defines units of "small" capacity as those with a heat throughput of less than 250 MMBtu/h, while those capable of a heat throughput between 250 MMBtu/h and 850 MMBtu/h are designated of "medium" capacity. Combustion turbines capable of firing greater than 850 MMBtu/h are designated "large." This report focuses on combustion turbines used in the electric power industry. Combustion turbines used in the electric power industry rarely process heat throughput less than 250 MMBtu/h, corresponding to approximately 25 MW output. More typical are units with heat throughput between 250 MMBtu/h and 850 MMBtu/h, corresponding to approximately 90 MW. Most combustion turbines in the electric power industry that are smaller than 60 MW are of "aeroderivative" design – that is, adapted from turbines initially designed for propulsion. Most combustion turbines intended for power generation with a rated capacity greater than this 60 MW threshold are called "frame" turbines. Within the latter category, several frame classes exist reflecting size, combustor firing temperature, and materials of construction. Specifically, combustion turbines of Class E, F, and H generally reflect higher firing temperature and refinement to the hot gas path that improve output.

This analysis reviews EPA's categorization considering the EIA data, which although informative does not distinguish between the different large turbine frame types. The population distribution of both simple and combined cycle units is evaluated, and considered in the context of utility applications.

Total Unit Population

Figure 2-1 presents the population distribution of existing gas turbines of 25 megawatts (MW) or greater, according to nameplate generating capacity (in MW).[9] A total of approximately 2,850 units exceed 25 MW. Figure 2-1 shows that the mid-point of the population corresponds to a generating capacity of 92 MW, roughly around EPA's designation of 850 MMBtu/h as the threshold for large combustion turbines. Figure 2-1 also reveals a cluster of approximately 250 units of about 60 MW capacity, reflecting popular aeroderivative designs. The figure also shows 90% of the combustion turbine population generates less than 200 MW; with the upper 4% of the population capable of 300 to 475 MW of capacity.

[8] Data are derived from Energy Information Administration Form 860, presuming heat throughput reported is that specified by the turbine supplier at ISO conditions.

[9] Generating capacity in megawatts is determined assuming a heat rate of 10,000 Btu/kWh for units between 250 and 850 MMBtu/h, and 9,000 Btu/kWh for units exceeding 850 MMBtu/h.

Unit age for simple and combined cycle duty is presented in Table 2-1 and Figure 2-2. Table 2-1 describes for simple and combined cycle units the turbine population according to five intervals of years, while Figure 2-1 graphically presents the information as a fraction of the population.

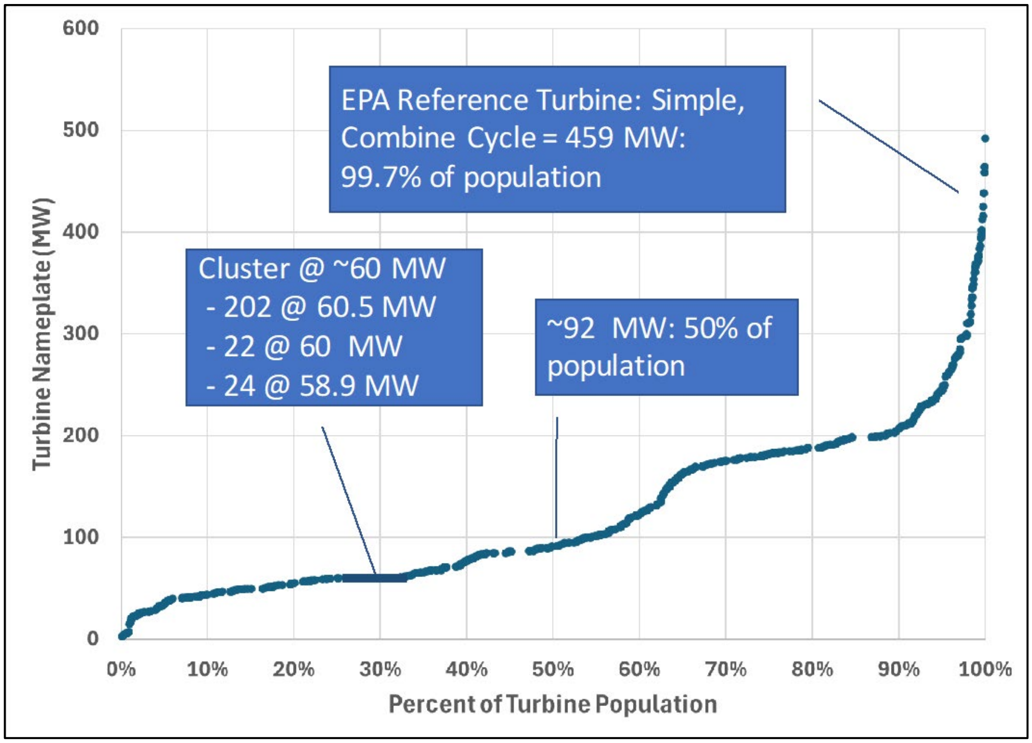

Figure 2-1. Combustion Turbine Population Distribution, by Nameplate Capacity

Table 2-1. Combustion Turbine Population By Age: Simple and Combined Cycle

Unit Age (Years)	Combined Cycle	Simple Cycle	Total
0-4	24	72	96
5-9	62	70	132
10-19	105	251	356
20-29	317	802	1,119
30+	148	511	659
Total	24	1,706	2,362

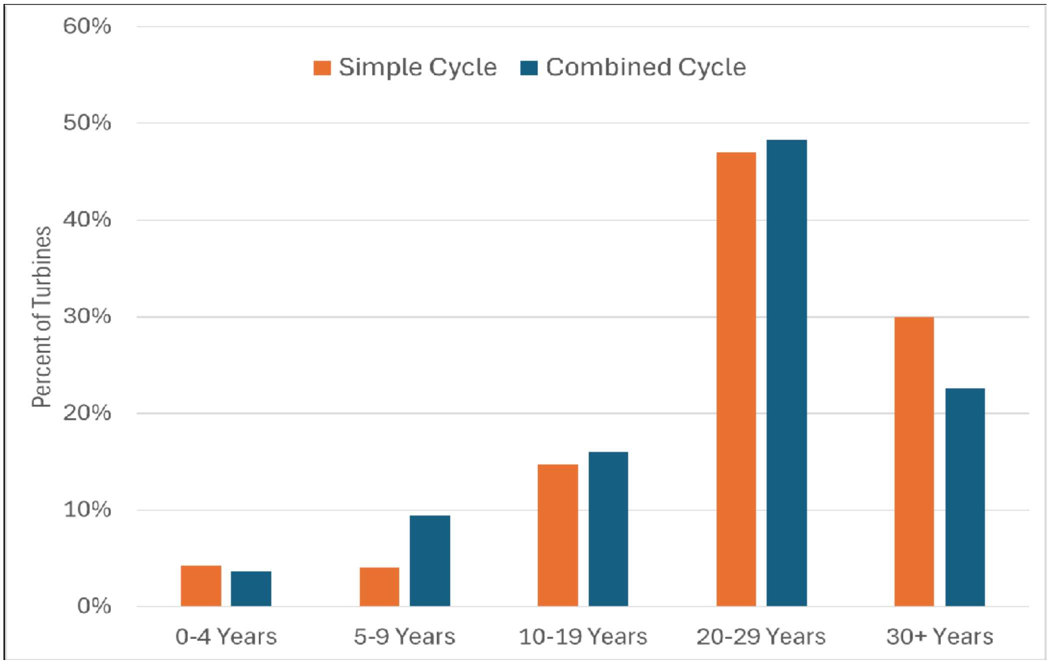

Figure 2-2. Combustion Turbine Population: Percentage by Age for Simple, Combined Cycle

The number of combustion turbines within defined increments of generating capacity is described by Figures 2-3 and 2-4 for simple and combined cycle applications. Figure 2-3 shows that the largest number of simple cycle units falls between 48 and 71 MW, approximately 640 units. Figure 2-4 shows that the largest number of combined cycle units falls between 178 and 213 MW, exceeding 400 units.

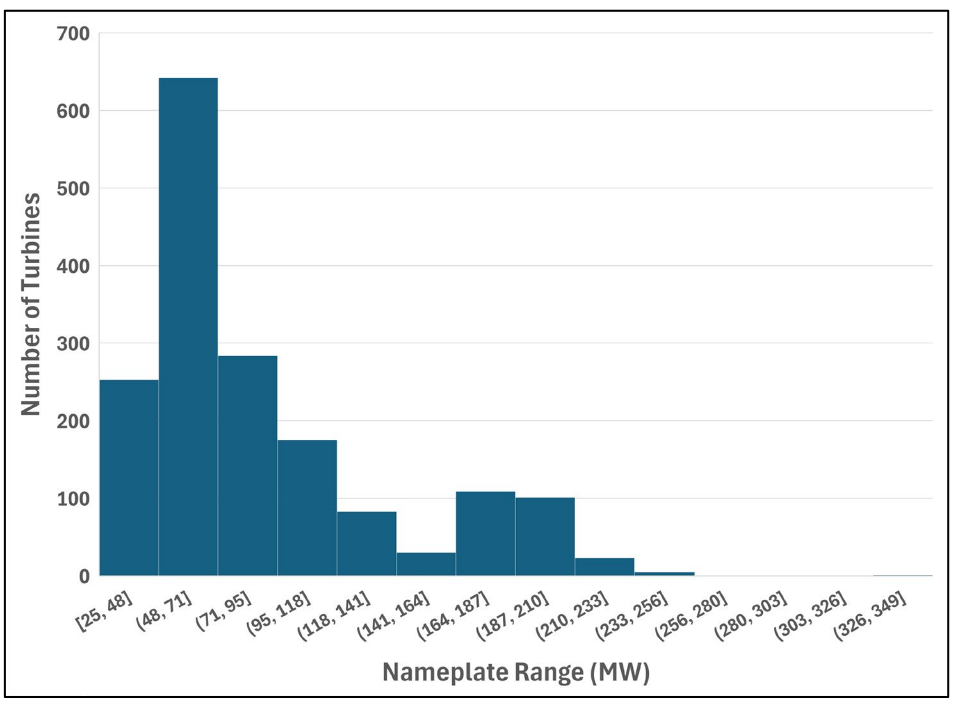

Figure 2-3. Population of Combustion Turbines by Nameplate: Simple Cycle Duty

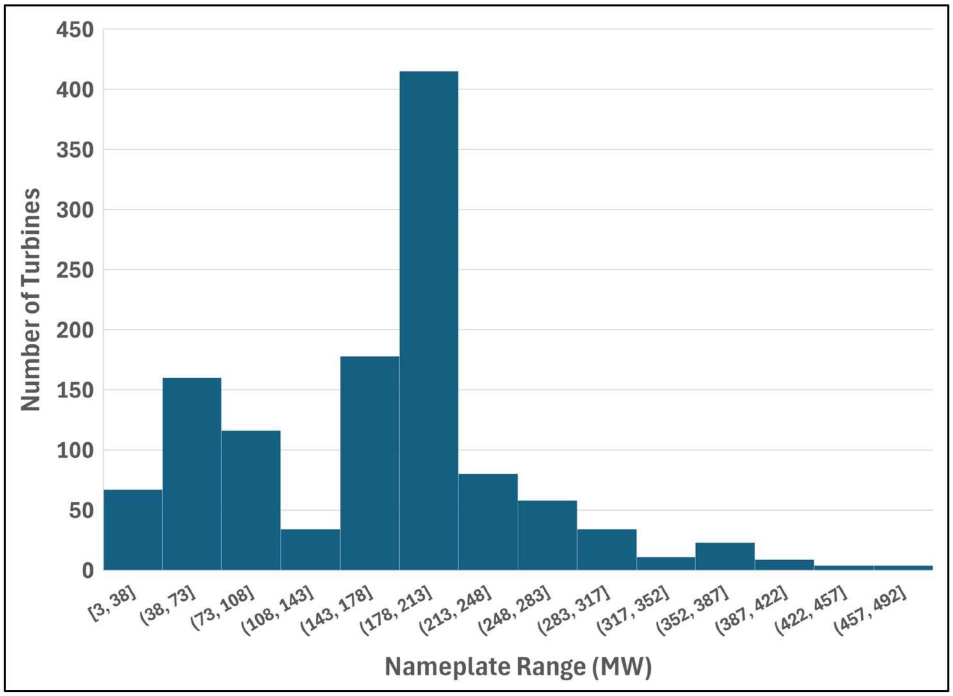

Figure 2-4. Population of Combustion Turbines by Nameplate: Combined Cycle Duty

EPA's proposed categorization of units by generating capacity thus appears to distinguish between the medium and large turbine population. The medium category encompasses primarily aeroderivative combustion turbines—typically used almost exclusively in simple-cycle configuration—and the large category addresses frame turbines, both simple cycle and combined cycle. EPA's proposed categorization, however, fails to distinguish between the four different classes of frame turbines, which have very different NOx emissions without an SCR.

Fuel Utilization

EPA solicited comments on NOx emissions from multiple fuels, including hydrogen. Comments are offered in this section.

Multiple Fossil Fuels

Many combustion turbines are designed for multiple fuel use, either for startup or backup duty in the event of loss of the main fuel supply (which is almost always natural gas). The annual fuel use of the population is reported in EIA Form 860. For combustion turbines in combined cycle application, a total of 22% of units (267 of 1193) report capability to switch between fuel oil and natural gas, while for simple cycle units a total of 37% (633 of 1706) report the same. Almost without exception, fuel oil and gas are not contemporaneously fired – the state-of-the-art dry low NOx combustors are not capable of managing the injection, mixing, and volatilization of liquid fuel while minimizing NOx and particulate matter. Fuel oil is used for startup or as an alternative fuel if supplies of natural gas are curtailed, or cost prohibitive.

A total of 177 combustion turbines reported being capable of "co-firing" describe firing natural gas and, depending on availability, a secondary gaseous fuel such as refinery off-gas or renewable natural gas (biogas).

Hydrogen

Each of the major combustion turbine suppliers are developing advanced combustors capable of firing hydrogen, while attempting to arrest any increase in NOx emissions due to the higher flame temperature. However, at present none of these suppliers have released quantitative data describing NOx emissions with hydrogen, except to say generally that such emissions should not be higher than what would be achieved with natural gas. More important, almost all data is short-term – recorded over hours of operation. The following summaries are noted:

- Mitsubishi Hitachi Power Systems reports results from the 501J turbine, featuring the "multi-cluster" combustor with 30% firing hydrogen capability, but claims the capability to "…maintain emissions compliance capability with hydrogen blend."[10]

- The New York Power Authority noted that co-firing hydrogen by up to 35% in a GE LM6000 SAC increased NOx by 24%, remedied by adjustments to the NOx control means (water injection); this result will not be applicable to dry low NOx combustors.[11]

- GE completed tests at Long Ridge Energy Generation, monitoring performance from a 485 MW combined cycle unit featuring a 330 MW 7HA.02 gas turbine. This test evaluated a 5% blend of hydrogen (by volume) in March of 2022, operating for an undisclosed period. NOx emissions have not been publicly disclosed.[12]

- Siemen report results with 270 MW SGT6-6000G turbine, firing 39% hydrogen, reporting NOx equivalent to natural gas (25 ppm at 15% O2).[13]

- Ansaldo describes the NOx control capability of its sequential combustion systems such that emissions "…can be brought down to very low levels" but does not cite quantitative values.[14]

As EPA is aware,[15] the conventional metric of NOx as a concentration (ppm) in combustion products is not a valid means to compare emissions between hydrogen and natural gas, as the

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[10] *Taking Gas Turbine Hydrogen Blending to the Next Level*, EPRI, September 2022.

[11] *Hydrogen Co-firing Demonstration at New York Power Authority's Brentwood Site: GE LM 6000 Gas Turbine*, September 2022.

[12] https://www.powermag.com/first-hydrogen-burn-at-long-ridge-ha-class-gas-turbine-marks-triumph-for-ge/

[13] *Constellation Completes Hydrogen Blending Test at Alabama Gas-fired Plant*, Power Engineering, May 24, 2023. Available at https://www.power-eng.com/news/constellation-completes-hydrogen-blending-test-at-alabama-gas-fired-plant/#gref.

[14] https://www.powermag.com/ansaldo-energia-reports-hydrogen-breakthrough-for-gas-turbine-sequential-combustion-technology/.

[15] 89 Fed. Reg. at 101338. Footnote 52.

background combustion products differs. NOx for hydrogen firing should be reported on a mass-rate basis or a correction factor applied for a concentration basis.[16]

Conclusions

The following concluding observations drawn are:

- EPA's categorization of combustion turbines as medium and large seems to reflect the power industry's population of turbines, in one respect recognizing roughly the distinction (and different characteristics) between aeroderivative-class and frame units.

- EPA's categorization of all frame turbines in a generic "large" subcategory does not distinguish between main classes of units with substantially different characteristics: E-class units (majority at approximately 90-150 MW); F-class units (majority about 200-315- MW); and the largest, H-class units (as large as about 570MW).[17]

- Almost without exception, combustion turbines do not fire fuel oil and natural gas contemporaneously, a trend that will continue in new state-of-art combustors that are designed for low NOx conditions without water injection. Data from EIA Form 860 does reveal that a total of 177 units out of the population of approximately 2,500 are capable of contemporaneously firing alternative fuels. These appear to be mostly gas phase – such as refinery off-gas and renewable natural gas (e.g. biogas).

- The limited commercial experience with hydrogen does not provide a basis for EPA to set NOx limits. Each of the major combustion turbine suppliers developing means of hydrogen firing has not reported specific NOx emission rates – either on a mass basis or concentration basis (corrected for the change in hydrogen gas composition). The lack of publicly available data prevents confidently predicting NOx production rate capabilities.

[16] *Taking Gas Turbine Hydrogen Blending to the Next Level*, EPRI, September 2022.
[17] There is some overlap in the size between these various classes.

SECTION 3. CRITIQUE OF ALTERNATIVE MASS-BASED OUTPUT NOx LIMIT

The EPA has proposed to replace NOx limits based on heat input – typically expressed as lbs/MMBtu, which equate to a part per million (ppm) basis.[18] The proposed alternative mass-based output is defined by the tons of NOx, normalized by unit generating capacity, accounted for over a calendar year. The feasibility of utilizing this alternative is addressed in this section.

EPA proposed five scenarios of NOx mass limits for medium and large sized gas turbines, equivalent to a 12-month capacity factor and NOx emission rate (as ppm). Table 3-1 summarizes the five scenarios proposed, and the calculation basis for each.

Table 3-1. Summary of Mass-Based Emission Rates as Proposed by EPA

Turbine	Calculation Basis		Equivalent Tons NOx/MW per Calendar Year
	12-Month Capacity Factor (%)	NOx ppm (4-hr standard)	
All	>20	25	0.75
Medium	N/A	25	0.75
Medium	15	20	0.45
Large	20	15	0.45
Large	15	7	0.21

EPA contends that mass-based limits simplify the regulatory actions. However, each restricts the capacity factor of a unit, in some cases severely, thus compromising the usefulness of the investment and making these proposed limits unworkable.

Capacity Factor Limitations

Each of the five scenarios of NOx mass rate limitation restrict operation to varying degrees, but most severely for large combustion turbines. Tables 3-2 through 3-4 report the equivalent limitation to capacity factor for three scenarios of NOx mass limits of 0.75, 0.45, and 0.21 tons/MW/calendar year. These subsequent tables report the capacity factor equivalent limitation for a range of NOx emissions at both part load and high load, and the fraction of operating time at high load. In these tables, average NOx emissions at part load are assumed to range from the present KKKK rate of 96 ppm to theoretical, lower rates (for illustration purposes only) of 75 and 50 ppm. NOx emissions at high load are assumed to vary from 25 ppm to 3 ppm, the later required SCR control.

[18] NOx emissions in terms of heat input as lbs/MMBtu can be expressed on part per million (ppm) basis, using EPA-derived "f-factors" that translate heat throughput into gas volume. The conventional reporting means is referring to an oxygen (O_2) content of 15%.

Table 3-2 reports the equivalent limitation in capacity factor imposed when NOx at part load is controlled to the present KKKK limit of 96 ppm. For the most stringent limit of 0.21 tons/MW/calendar year, and controlling NOx to 3 ppm, capacity factor is restricted to 26% for operation 95% of time at high load. For the same 95% of operating time, all other high load scenarios with NOx control restrict capacity factor from 7 to 21%. The NOx mass limit of 0.45 results in up to a 56% capacity factor for 95% of time at high load and 3 ppm NOx, but imposes a 20% capacity factor limit for three-quarters of the options. The NOx mass limit of 0.75 tons/MW/yr is (of course) the least restrictive. But for that mass limit, the capacity factors of units operating as high as 80% of the time at high load are severely restricted.

Table 3-2. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 96 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					Mass-based Limit 0.75 Tons/MW/Year			
96	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	26%	21%	15%	11%	7%	56%	45%	32%	23%	15%	93%	75%	54%	38%
90	16%	14%	11%	9%	6%	35%	30%	24%	19%	13%	58%	51%	40%	31%
80	9%	9%	8%	6%	5%	20%	18%	16%	14%	11%	33%	31%	27%	23%
70	6%	6%	6%	5%	4%	14%	13%	12%	11%	9%	23%	22%	20%	18%
60	5%	5%	5%	4%	4%	11%	10%	10%	9%	8%	18%	17%	16%	15%
50	4%	4%	4%	4%	3%	9%	8%	8%	8%	7%	14%	14%	14%	13%

Table 3-3 presents results for the same mass limits of 0.21, 0.45 and 0.75 tons/MW/calendar year, but for an assumed 75 ppm part load NOx emissions. The limit of 0.21 NOx tons/MW/calendar year restricts capacity factor to 30% for operating 95% of time at high load, and 3 ppm NOx. All but three scenarios restrict capacity factor to less than 20%. The limit of 0.45 NOx tons/MW/calendar year about doubles the allowable capacity factors, but still restricts more than three-fourths of the options to less than 20%. The capacity factor at these conditions of well controlled NOx (3 ppm) operating 95% of time at high load is restricted to a maximum annual basis of 65%. The NOx mass limit of 0.75 tons/MW/yr is the least restrictive, but it still severely limits the capacity factor of units operating at high load at 80% or even 90% of the time.

Table 3-3. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 75 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					Mass-based Limit 0.75 Tons/MW/Year			
75	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	30%	24%	16%	11%	7%	65%	50%	35%	24%	16%	100%	84%	58%	40%
90	20%	17%	13%	10%	7%	42%	36%	28%	20%	14%	70%	60%	46%	34%
80	12%	11%	9%	7%	6%	25%	23%	19%	16%	12%	41%	38%	32%	26%
70	8%	8%	7%	6%	5%	17%	17%	15%	13%	11%	29%	28%	25%	22%
60	6%	6%	6%	5%	4%	13%	13%	12%	11%	10%	22%	22%	20%	18%
50	5%	5%	5%	4%	4%	11%	11%	10%	10%	9%	18%	18%	17%	16%

Table 3-4 presents results for an assumed, theoretical part load NOx rate of 50 ppm and the same three mass limits. These conditions limit capacity factor to less than 37% for units operating at 95% of time at high load, with 3 ppm NOx. All but three of the operating options at 0.21 NOx tons/MW/calendar year are limited to less than 20% capacity factor, while for 0.45 tons/MW/Yr about half of the cases are limited to less than 20% capacity factor. Similar to other cases, a mass limit of 0.75 tons/MW/Yr severely limits the capacity factor of units to 80% at high load.

Table 3-4. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 50 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					Mass-based Limit 0.75 Tons/MW/Year			
50	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	37%	28%	18%	12%	8%	80%	59%	39%	26%	16%	100%	99%	65%	43%
90	26%	21%	15%	11%	7%	56%	45%	33%	23%	16%	93%	75%	55%	39%
80	16%	14%	12%	9%	7%	35%	31%	25%	20%	14%	58%	51%	42%	33%
70	12%	11%	9%	8%	6%	25%	23%	20%	17%	13%	42%	39%	34%	28%
60	9%	9%	8%	7%	6%	20%	19%	17%	15%	12%	33%	31%	28%	25%
50	8%	7%	7%	6%	5%	16%	16%	15%	13%	11%	27%	26%	24%	22%

The following observations per EPA's proposed mass NOx rate are offered:

- EPA's proposed mass-based output limits impose strict operating barriers on commercial units which would interfere with a unit's ability to deliver power and balance the grid. The use of any of the mass-based limits proposed by EPA would impose such low limits which would compromise grid reliability.

- Even large units that are equipped with stringent NOx control technology will be severely limited in operation at the proposed limit of 0.21 tons/MW/yr. As an example, an SCR-equipped unit operating at high load for 95% of time and emitting 3 ppm at high load (i.e., likely a highly-efficient, highly-controlled combined cycle unit) and a theoretical 50 ppm at part load is restricted to a 37% capacity factor. This same combustion turbine without SCR and emitting, for example, 9 ppm of NOx at high load is limited to less than 18% capacity factor.

- At 0.45 NOx tons/MW/yr, the same large SCR-equipped combustion turbine emitting a theoretical 50 ppm at part load and operating for 90% of time at high load while emitting 3 ppm, is limited to 56% capacity factor – negating approximately half of its value from the wholesale power market. The imposed limit to this capacity factor is more severe if the combustion turbine supplier is able to meet a theoretical 75 ppm at part load; even with SCR controlling NOx to 3 ppm for 90% of operating time, capacity factor is limited at 42%. The limit of 0.75 tons/MW/Yr also severely limits capacity factors.

SECTION 4. PART LOAD OPERATION

Section 4 addresses EPA's concern that owners will intentionally operate unit at part load (less than 70% capacity) to avoid meeting the lower NO emission rates required for high load.

In the preamble of the proposed rule, EPA expresses concern regarding a "… *regulatory incentive for owners/operators to reduce operating loads so that the part-load standard is applicable."* Section 4 shows that such actions are commercially unrealistic due to significant cost consequences of restricting operation. Section 4 also describes how simple cycle units operate in the present marketplace and presents results of a cost evaluation addressing EPA's concern.

Present Simple Cycle Duty

Simple cycle combustion turbines operate in the present wholesale power marketplace as peakers. These units startup relatively frequently, get to high load rapidly (reported as 10 minutes for the Ocotillo units), and thereafter operate primarily at high load. Minimal time is expended in transition between startup and high load. Figures 4-1 and 4-2 depict this duty for an example simple cycle unit operating at the Ocotillo power station in Arizona.

Figure 4-1 presents the duty cycle describing heat throughput over the 12 months of 2023 and shows the unit rapidly transits from startup to high load. The operating hours are shown to cluster around extremely low and high load.

Figure 4-2 presents the same data but with more clarity documenting that most operation is at less than 10% nameplate capacity, which is essentially startup, or between 90-100% of nameplate heat throughput.

The annual capacity factor for the unit as shown is approximately 18%, implying the unit operates for about 1,600 hours annually. Most units operating in simple cycle are described by a load profile as shown in Figures 4-1 and 4-2.

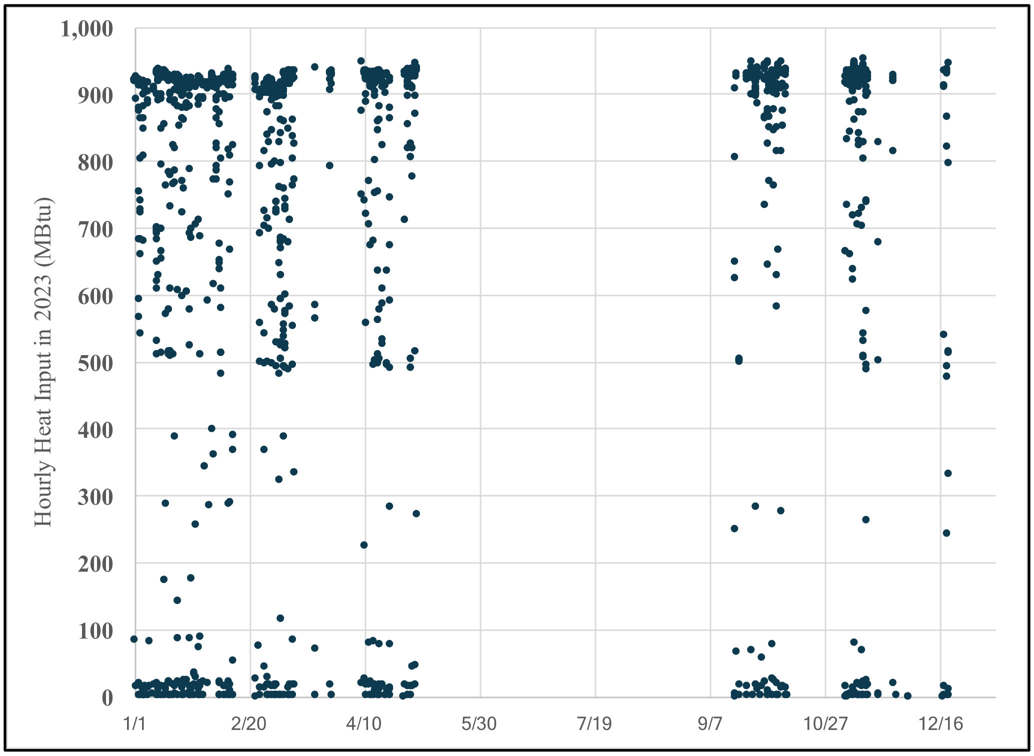

Figure 4-1. Operating Duty for an Ocotillo Simple Cycle Unit

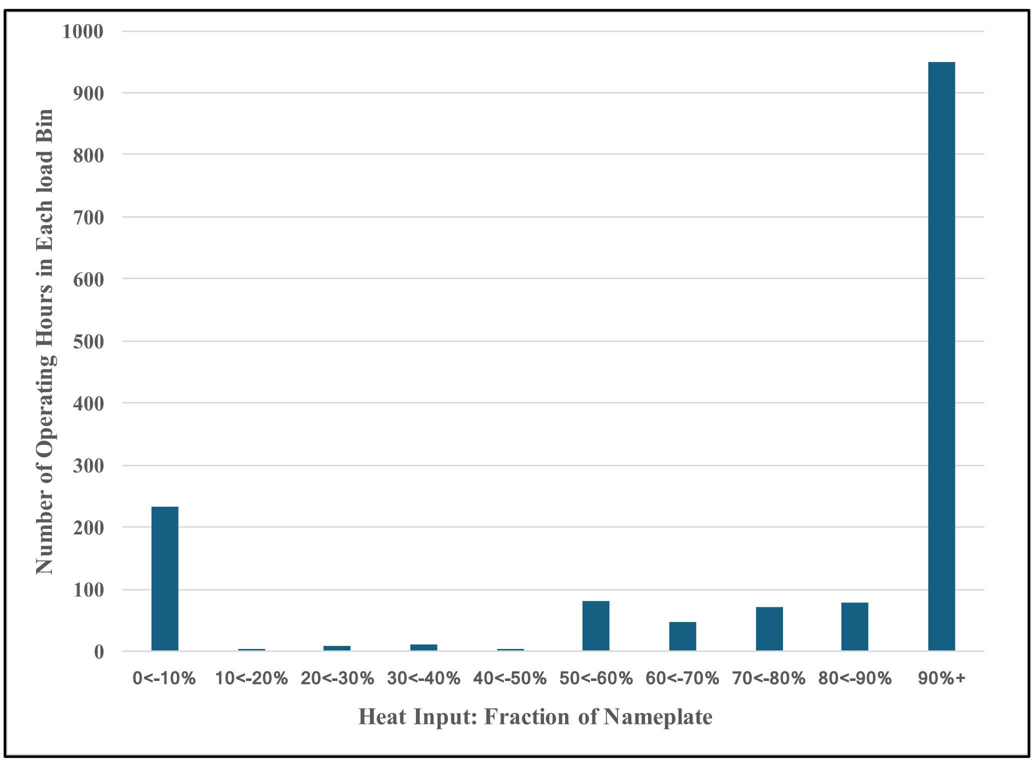

Figure 4-2. Operating Hours in Ten Load Bins: Ocotillo Example Unit

Intentional Low Load Operation to Avoid SCR

This analysis compares the revenue available for a large combustion turbine (105 MW) for two scenarios. The first scenario considers a unit not equipped with SCR that intentionally limits operation to part load duty. A second scenario considers the same unit equipped with SCR that operates, as most combustion turbines do in practice, primarily at high load. For this example, operating duty is modeled after the Ocotillo simple cycle unit represented in Figures 4-1 and 4-2.

The performance and SCR cost for the reference units are adopted from the National Energy Technology Laboratory's (NETL) simple cycle cost evaluation.[19] Table 4-1 summarizes the conditions of the analysis, including the capital cost for process equipment both with and without SCR, and the operating conditions. The two scenarios employ different heat rates, reflecting compromised thermal performance and higher fuel cost at part load.

Table 4-1. Cost Basis: Medium Simple Cycle With and Without SCR

	Capital Cost,[20] ($)	Operating Conditions
With SCR	148.7 M	• 100% capacity for 1,600 – 1,800 operating hours • Full load heat rate 8,545 Btu/kWh • Aux power for an attemperation fan[21]
Without SCR	142.8 M	• 70% capacity for 1,600-1,800 operating hours • Part load heat rate: (9,372 Btu/kWh)

By intentionally operating at no more than 70% load, the owner of the unit without SCR is limiting the generation and revenue.

Figure 4-3 shows net revenue for the interval of 1,600 – 1,800 operating hours for the unit without SCR, intentionally limited to part load, compared to revenue for an SCR-equipped unit. The calculation for net revenue for the SCR-equipped unit includes the annual capital charge and operating cost for the SCR process[22] and the benefit of lower fuel cost due to lower heat rate. Even with higher cost to pay for SCR, this case derives an additional $0.80M annually. An owner intentionally operating a simple cycle unit of this type without SCR will forgo this additional revenue. The contrast would be more severe for larger and combined cycle units.

Consequently, there is no financial gain to restricting operation to part load duty to avoid the capital and operating cost for SCR; in fact, there is a financial penalty to do so.

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[19] NETL 2023 Cost Study. See Case SC2A.

[20] Capital cost is expressed as Total Overnight Cost (TOC), excluding financing charges.

[21] The gas temperature exiting a combustion turbine operating in simple cycle can significantly exceed 1,000 F, well above the accepted temperature for reliable SCR catalyst lifetime. To remedy this, simple cycle SCR applications use an attemperation fan to dilute turbine exhaust with ambient air, lowering gas temperature to the conventional average of 700-800 F where SCR is more reliably applied.

[22] The SCR cost penalty considers a capital recovery period of 20 years and fixed and variable operation cost defined by NETL, a natural gas price of $1.90 /MMBtu, and a wholesale power price of $25/MWh.

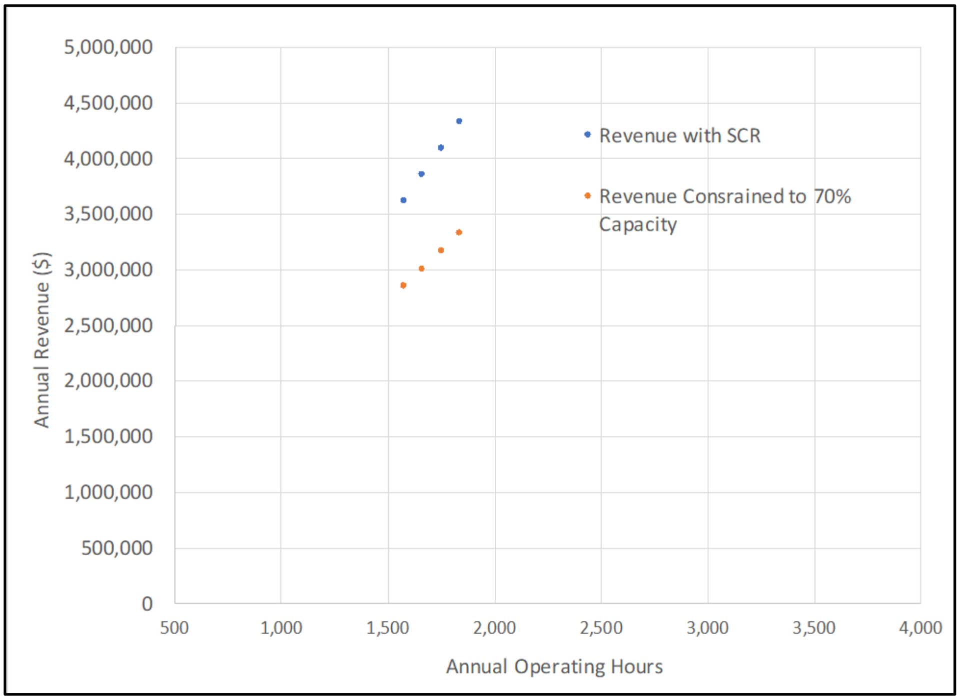

Figure 4-3. FGD Equipped Units: Role of 3-Year Capacity Factor

A significant contributor to the cost penalty is the higher capital for the generation that can be delivered to the wholesale market. Specifically, an owner following the strategy reflected in EPA's concern would be paying for capacity they never utilize. Using the same 105 MW combustion turbine generating station as reference, the capital requirement of $142.8 M equates to a normalized cost of $1,360/kW for high load duty. However, intentionally restricting the output to less than 70% of full capacity elevates the cost per usable power to $1,943/kW.

Limiting Operating Hours at Low Load

EPA inquired as to the feasibility of limiting part load operation to control NOx emissions, by requesting "comment on a maximum limit to the number of hours per year that the part-load standard can be applied."[23]

As noted in the preceding section, there is no economic benefit to intentionally restrict operation to below the high load capacity. The economic penalty is not a hypothetical calculation, as shown in Figure 4-3. The cost penalty for such actions is substantial, as shown in Figure 4-3.

Figures 4-4 and 4-5 show that, currently and in the past, some units operate at part load more than others. This is not the result of a perverse incentive that EPA suggests (currently, the most stringent high load NOx standard under KKKK is 15 ppm). Rather, if a unit is currently spending more time than another unit at part load, it is because the market demands it.

[23] 89 Fed. Reg. 101,320.

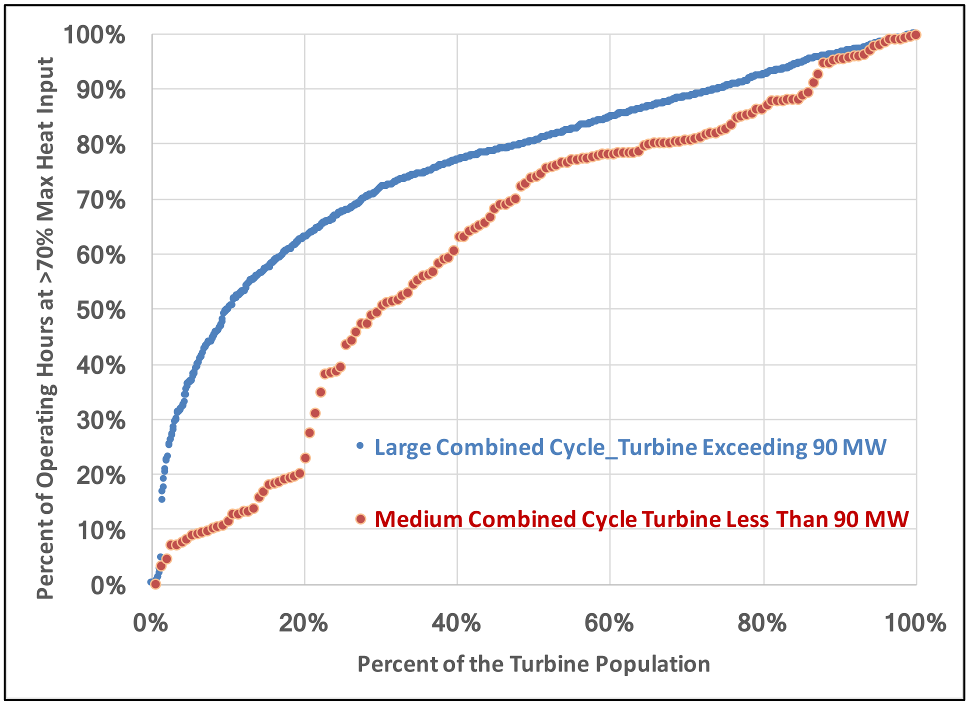

Figure 4-4. Operating Hours Exceeding 70% Load: Medium, Large Combined Cycle Units

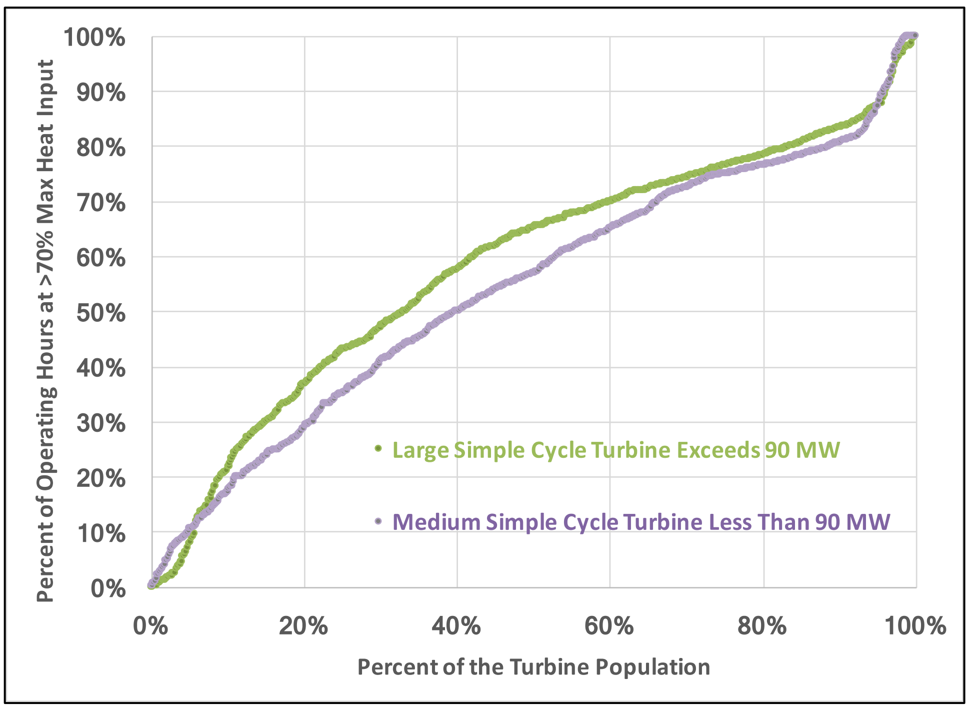

Figure 4-5. Operating Hours Exceeding 70% Load: Medium, Large Simple Cycle Units

Figures 4-4 presents the fraction of operating time (vertical axis) at high load for large and medium combined cycle units, as a function of the percent of turbine population. Figure 4-4 shows units at the mid-point of the population generally expend 80% of operating time at high load, demonstrating a preference for operating at conditions requiring SCR NOx controls.

Conversely stated, units at the population mid-point expend only 20% of their time at part load – the mode EPA is concerned would be popularized to avoid a strict NOx limit. Combined cycle turbines of the medium category exhibit a similar trend – units at the mid-point expend 75% of operating time at high load duty. Conversely stated, only 25% of operating time for these units is expended at part load. Any operations that are not consistent with the market's signal for power either compromises grid stability or requires non-economic operations.

Figures 4-5 presents analogous information for simple cycle units of the large and medium categories. Large simple cycle units at the population midpoint expend 66% of their operating time at high load, showing preference for conditions that require strict NOx control. Medium simple cycle units exhibit a similar trend, expending 57% of operating time at high load. In both cases the primary reason for increased operation at part load is the increased frequency of startup/shutdown cycles for these peaking units, and not extended operations at part load.

Limiting operation of these dispatchable resources risks the ability to manage peak demand and grid stability. Critical reliability services provided by simple cycle combustion turbines are rapid load ramping, and maintaining stable voltage and acceptable frequency response. Addressing these concerns, PJM's president, testifying to Congress on the need for dispatchable generation, noted the need to key role of existing sources to support reliability while non-dispatchable resources are introduced into the grid.[24]

The following conclusions are offered:

- Most simple cycle units operate at two modes – either idling or low part load (< 10%) of nameplate capacity, or high load as demanded by wholesale power market forces.

- The intentional operation of a unit at part-load duty to avoid requiring SCR incurs a cost penalty in terms of significant forgone revenue. Further, such an intentional limit restricts the capacity of these dispatchable resources, presenting risk to grid stability.

- Combustion turbine operation at part load is rarely intentional, and if necessitated will be to "balance" the grid to offset variable non-dispatchable asset generation.

[24] PJM Interconnection, Testimony of Manu Asthana President and CEO (Mar. 25, 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf

- Arbitrarily constraining operation at part load imposes major limits to asset duty:
    - Half of the medium and large combined cycle turbines (566) expend only 20-25% of their operating time at part load.
    - Similarly, half of the population of medium simple cycle turbines (505) expend almost half (43%) of their operating time at part load.
    - Half of the large simple cycle turbines (422) expend about 34% of their operating time at part load.

Such constraints would limit options to balance the distribution grid, and result in compromising reliability.

SECTION 5. ACHIEVABILITY: HIGH LOAD NOx LIMITS of 2, 3 ppm

The EPA, in considering NOx emission rates for high load duty, solicits comments on candidate NOx rates. Specifically, EPA state:

Based on current information, it does not appear that 2 ppm NOx is consistently achievable for highly efficient large combustion turbines. The EPA is soliciting comment on the ability of large frame simple cycle turbines using SCR to achieve the proposed emissions rate.[25]

This section presents comments on the feasibility of meeting a 2 ppm and a 3 ppm NOx limit. This report does not assess what an appropriate NOx limit would be.

In the rulemaking docket, EPA reports the results of an analysis evaluating the extent to which a given NOx emission rate can be successfully attained.[26] The referenced document (EPA-HQ-OAR-2024-0419-0020_attachment_1) reports the percentage of operating time over which 90 simple cycle and 75 combined cycle units achieve NOx emissions of 2, 4, and 5 ppm for averaging periods ranging from 4-hours to 30-days. EPA appears to judge the "achievability" of these rates by the fraction of operating time these units successfully meet any given rate. This "success rate" ranges from approximately 50% up to 100%, with most exceeding 90%.

This section reports an attempt to replicate EPA's results using the following methodology:

- Hourly emissions data for the year 2023 extracted from the Clean Air Markets Program Data (CAMPD) web portal

- Each operating hour is classified as high load or part load, by comparing reported heat throughput to the 70% of Reported High Load Rating (MMBtu/h) (Column H) to delineate between operating levels.

- The part-load emission rate limit is set at 0.37 lbs/MMBtu (96 ppm).

- High load NOx emission limits of 2, 3, and 4 ppm are utilized (corresponding to 0.0074, 0.01105, 0.0147 lbs/MMBtu), respectively.

- NOx emissions are calculated for 4-hour averages, when there are four hours of operation. NOx emission averages based on weighted heat throughput are calculated and rounded to the nearest .001, matching the reported accuracy of the hourly CEMS data.

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[25] Fed. Reg. at 101336.

[26] *See* CT NOx List, available as attachment 1 in Docket ID No. EPA-HQ-2024-0419-0020.

- The 4-hour emission rate limits are calculated weighted by heat throughput, using 96 ppm for duty at less than 70% of maximum heat throughput, and either 2, 3, or 4 ppm at high load.

- The 4-hour emission rate averages for each unit are compared with the calculated 4-hour limits to assess theoretical compliance percentages.

Table 5-1 presents results of this analysis for six simple cycle and five combined cycle units.

Table 5-1. Probability of Meeting 2, 3, and 4-ppm NOx Limits: Comparison of Two Analyses

				Percentage of 4-Hour Average ER Meeting Standard					
				4 ppm (0.015 lbs/MBtu)		3 ppm (0.011 lbs/MBtu)		2 ppm (0.007 lbs/MBtu)	
		Average of 4Hr ER	Max of 4Hr _ER	EPA	This Study	EPA	This Study	EPA	This Study
Scattergood 7	Simple	0.008	0.027	99.9%	100.0%	99.3%	100.0%	91.7%	87.6%
Panoche 1	Simple	0.009	0.056	99.8%	99.6%	98.9%	97.7%	72.9%	91.4%
Montana 1	Simple	0.012	0.052	99.9%	99.9%	91.4%	97.6%	55.9%	37.2%
Desert Basin	Simple	0.019	0.168	89.7%	95.3%	86.7%	94.7%	67.8%	58.6%
Tejas 1	Simple	0.017	0.123	92.5%	95.4%	81.7%	55.4%	N/A	50.6%
Canal Station	Simple	0.022	0.026	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Dresden 1A	Combined	0.012	0.529	100.0%	99.9%	67.7%	44.1%	19.7%	8.8%
Riviera RBCT5A	Combined	0.009	0.158	100.0%	100.0%	100.0%	100.0%	99.9%	99.8%
Eagle Valley GT1	Combined	0.005	0.092	100.0%	100.0%	100.0%	100.0%	99.9%	100.0%
Jackson CT-02	Combined	0.006	0.058	100.0%	100.0%	100.0%	100.0%	100.0%	99.0%
Potomac CT-01	Combined	0.005	0.078	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The results of calculations conducted in this study do not replicate EPA's results for all eleven example units. Results from this study project a lower frequency of compliance for three of eleven units for the 3 ppm limit, and six of eleven units for the 2 ppm limit. (For some units, this study projects a higher frequency of compliance rate than EPA). EPA, upon request, shared details of their methodology, revealing differences in treatment of substituted data, monitor downtime, and bias adjustment.[27] The project team considered these factors, as well as changes to other inputs in follow-up calculations, but results of the two analyses still could not be reconciled.

Results from both EPA and this study as reported in Table 5-1 show a 2 ppm limit is rarely met 100% of the time, even for combined-cycle units. For simple-cycle units, the percentage of time at which it is met is significantly lower. Only three of the 11 example cases are cited as successful for both EPA's and this analysis. The 3 ppm rate is achieved more often, as EPA

[27] Fellner, Christian, email personal communication to J. Cichanowicz et. al, *NOx Compliance Rate Methodology*, March 26, 2025.

projects 100% compliance for five of 11 units (most in combined-cycle duty), but the failure of six of the 11 units to meet 3 ppm suggests the compliance margin is small. Based on EPA's data and this analysis, there is no basis for a standard of 3 ppm, at least not for combustion turbines operating in simple-cycle mode.

In summary, the 2 ppm limit is too strict and not readily or consistently achievable. The 3 ppm limit can be met more frequently, but the compliance margin is small, suggesting challenges across the broad combustion turbine population, and especially for simple-cycle turbines. If EPA retains SCR as the technology requirement of the rule for some categories, it should adopt a standard higher than 3 ppm.

SECTION 6. SCR DESIGN AND OPERATION for PART LOAD

The EPA seeks comment on NOx controls for part load and for rapid changes in load, focusing on SCR design and operation. EPA solicits the following:

The EPA requests comment on the efficacy of combustion control technology operated in conjunction with SCR when units are in part-load operation.[28]

The EPA is soliciting comment on if it can be challenging to adjust ammonia injection rates during rapid load changes to maintain NOX emissions rates while at the same time minimizing ammonia slip….[29]

A response to these inquires is presented as follows.

SCR Process Design

The premise of SCR design is to provide uniform conditions of gas velocity, temperature, and composition entering the catalyst. Typically, the variance of gas velocity entering the catalyst should be maintained to +/- 10% per arithmetic average to maximize the usefulness of catalyst surface area. More important is the mixing of injected ammonia (NH_3) reagent and achieving a uniform ratio of NH_3/NOx. For combustion turbine applications requiring high (~75% or more) NOx removal, the NH_3/NOx ratio at the catalyst inlet should have a uniformity of 10%.

SCR reactors are designed to provide these conditions at high load and steady operation, but variances in load and the rate of change impose severe performance limits at part load. In one example, startup with a combustor pilot or diffusion flame presents a variability in NOx that can range from 10 ppm (near the combustor wall) to 70 ppm or higher. This variance must be eliminated by static mixers or other devices used to remedy imbalances in gas flow, temperature, and composition for SCR to be effective (assuming other difficulties are also resolved).

Gas Flow Mean Velocity, Distribution

Figures 6-1 presents sectional drawings of the transition duct for combined cycle SCR applications. Figure 6-1 shows ductwork expands by approximately a factor of three, from a nominal 20 x 20-foot cross section at the combustion turbine exit, to a 27 x 60-foot cross-section at the inlet of the first heat recovery steam generator (HRSG) tube bundle.

[28] Fed. Reg. at 101320.

[29] Fed. Reg. at 101325.

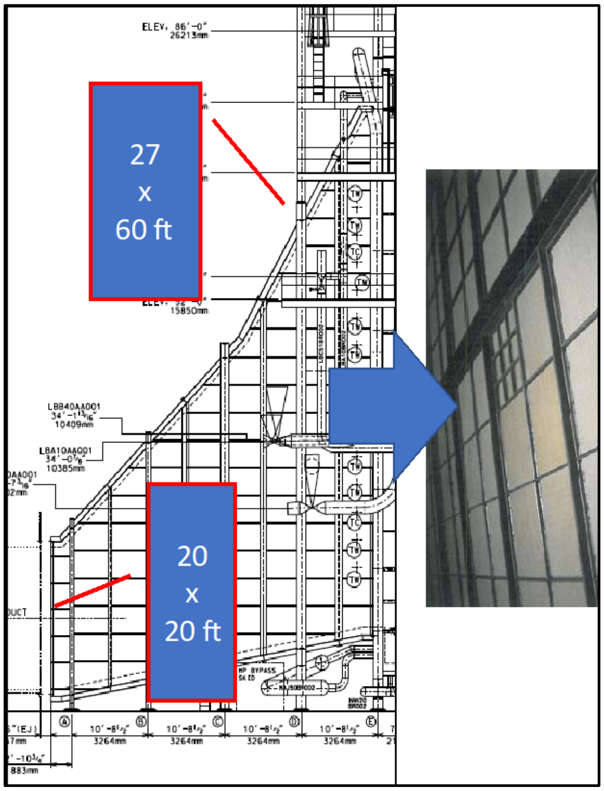

Figure 6-1. Ductwork Between Heat Recovery Steam Generator Inlet, First Tube Bundle

Ammonia Regent Mixing

More important than well-controlled and uniform gas mixing is a uniform NH_3/NOx ratio, ideally maintained to within 10% uniformity.

Figure 6-2 presents a typical NH_3/NOx distribution "fingerprint," characterizing the degree of uniformity of NH_3 and NOx across inlet ductwork of a simple cycle SCR reactor.[30] Figure 6-2 presents lines of constant NH_3/NOx ratio, with the value of "1.0" (or unity) reflecting the desired outcome of perfectly mixed NH_3 in the chemically correct stoichiometric proportion. The lines of constant NH_3/NOx stoichiometry less than unity reflect where NOx removal will be compromised; while those greater than unity reflect where residual NH_3 will be generated. The ideal NH3/NOx fingerprint features low density of lines, reflecting uniform NH_3/NOx ratio.

Part-load conditions, in particular less than 50%, challenge the task of achieving good mixing of NH_3 in the gas flow. The extent of mixing is defined by the momentum of NH_3, typically introduced within an air "jet" from the injection grid. The mixing of injected NH_3 is further enhanced by static mixers that impart turbulence to the gas flow. Static mixers are momentum-driven devices, thus lowering gas velocity to half or less than their value at full load compromises their effectiveness. Consequently, part load duty challenges achieving uniformity in process conditions and severely limits SCR performance.

[30] Martz, T.D. et. al., Gas Turbine SCR Performance Management: AIG Tuning and Catalyst Life Forecasting, Combined Cycle Journal, May 22, 2012.

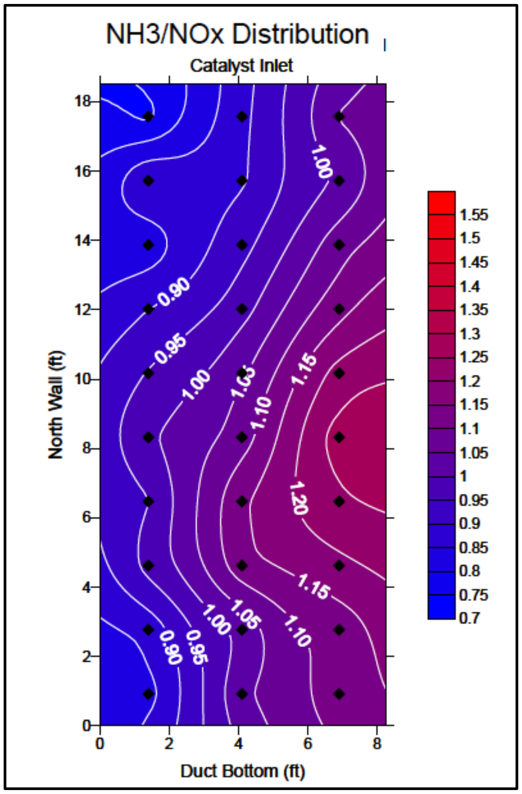

Figure 6-2. NH_3/NOx Distribution: Simple Cycle Application

Transient Conditions

Further complicating process design are rapid and frequent changes in conditions, such as transitioning from part load to high load within a short time period.

Unit Startup Rate

Figure 6-3 depicts the rate of change in load for a combined cycle unit under "hot-start" conditions, comparing the traditional design to "fast-start" units. Such "fast start" units, introduced into the turbine fleet over the last decade, enable a rapid increase in load. Figure 6-3 illustrates that the traditional hot-start mode can require up to 90 minutes to reach full load, as thick-wall tubes and turbine blades are heated at a prescribed rate to prevent thermal stress. Fast-start units are designed to do so in perhaps 30 minutes. These rapid load changes induce equally rapid changes in gas flow, temperature, and NOx content that impair SCR performance. Further complicating SCR performance is the "lag time" between the NH_3/NOx ratio introduced at the process inlet and that experienced at the catalyst surface. Since catalysts feature highly porous surfaces, injected NH_3 will penetrate the pores and be stored. This action introduces a time lag between NH_3 injected and that at the catalyst surface, which can compromise NH_3 (and lower NOx removal) for cases of load increase or generate excess NH_3 (and high breakthrough values) for load decreases.

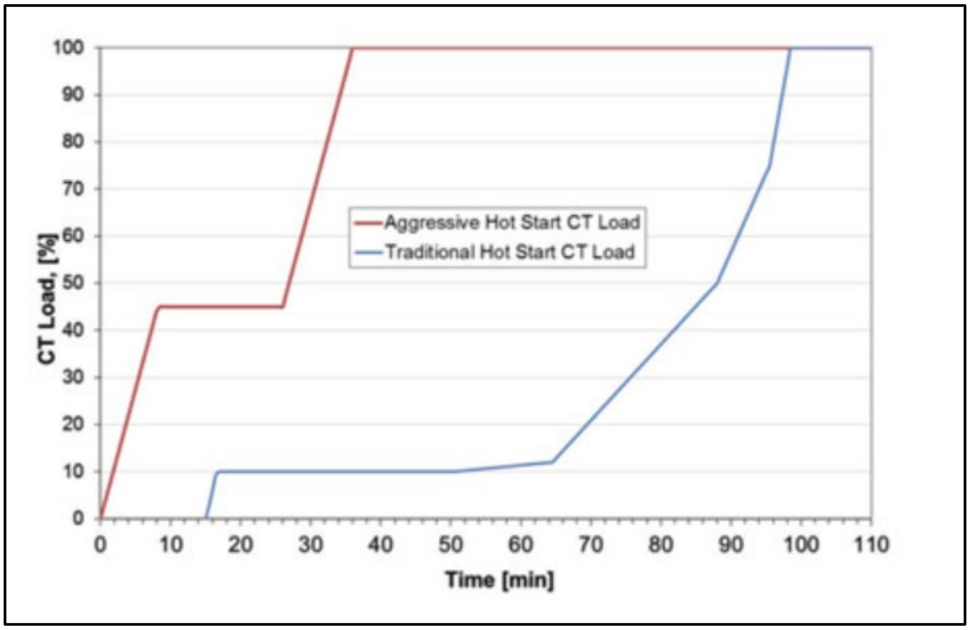

Figure 6-3. Combustion Turbine Load vs Time: Traditional vs. Fast Start Conditions

Transient Operation

Figure 6-4 presents startup data for a GE F-Series turbine. The data presented are (a) Load (yellow), (b) Gas Flow (blue), (c) NOx content (orange), and (d) SCR temperature. Figure 6-4 demonstrates, in the case of the turbine cited, highly variable NOx content, peaking at 70 ppm for a period of approximately 30 minutes, and SCR temperature that requires almost 3 hours to achieve the minimum for ammonia reagent injection (580ºF).

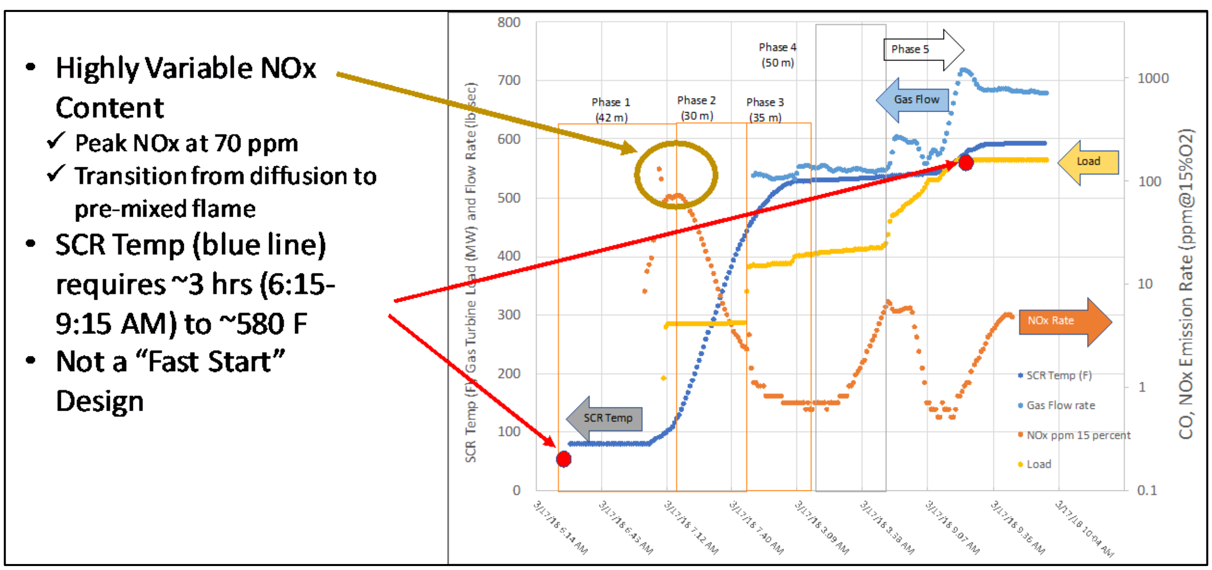

Figure 6-4. Startup Data: GE 7FA:1 x 1 Combined Cycle Arrangement

Consequently, several hours are required for SCR-driven NOx emission rates to be achieved. Although not a "fast–start" design, the description of process conditions in Figure 6-4 is representative for state-of-art generating units in a combined cycle.

A further depiction of highly variable conditions is presented in Figure 6-5. This figure shows the variability observed over 100 hours of rapid load changes. Most notable are variations in (a) gas temperature from 580 to 700ºF, within hours, (b) ammonia reagent injected, varying by a factor of 3 within hours, and (c) residual NH_3, which can approach 20 ppm.

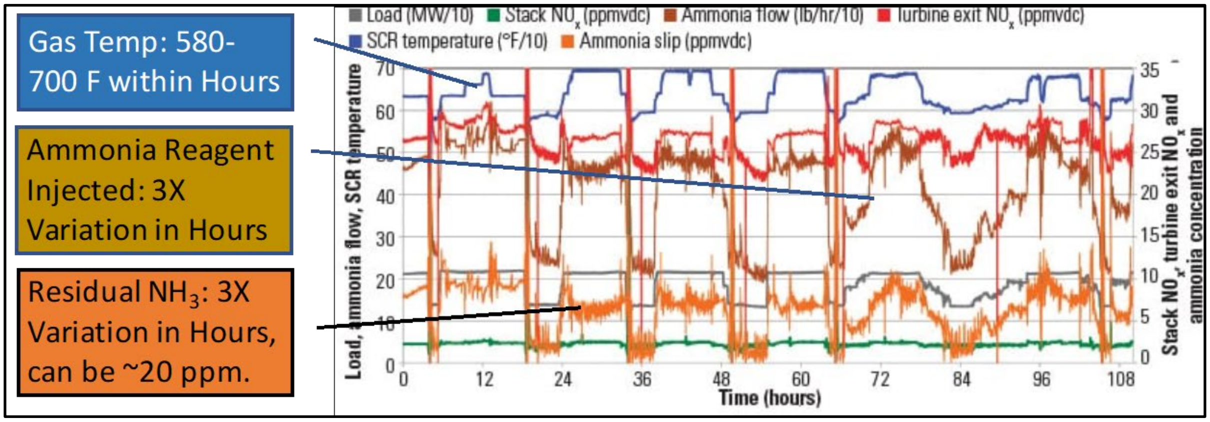

Figure 6-5. SCR Design and Operating Parameters: Highly Transient Conditions

The observation of residual NH_3 serves as a real-time indicator of imperfect conditions, a cumulative product of inadequate gas flow, temperature, and the NH_3/NO ratio.

These challenges to designing and operating SCR for low load and transient conditions are widely recognized, as noted in a recent publication:

> "When you operate advanced-technology machines at low loads, you tap out the capabilities of the design (Fig 6). The ammonia injection grid can't handle both the NOx levels at the maximum design output and what would be typical at 30-50% load, because of the corresponding changes in mass flow, temperature, and mixing."[31]

Concluding Observations

- Part load operation induces "spikes" in the process conditions that define SCR design – most notably NOx content, gas flow rate, and temperature. Abnormalities in these variables create conditions at an SCR reactor that increase the complexity of hardware design (such as for mixing), in most cases render the application of an SCR impractical.

- Part load conditions that compromise SCR design and operation are:

    - High NOx content observed at part load will vary widely during transitions between different burner operating modes.

[31] *Consider the Impact of New Operating Regimes on your SCR*, Combined Cycle Journal. https://www.ccj-online.com/consider-the-impact-of-new-operating-regimes-on-your-scr/.

- A low gas temperature at less than 580ºF provides a minimal reaction rate for NOx removal.
- Low-velocity gas flow, as little as one-fourth of the design value, which impairs both the mixing of ammonia reagent in the gas stream and the penetration of the ammonia and NOx into the pores of the catalyst surface.

Section 7. CRITIQUE OF EPA's COST EVALUATION

Section 7 critiques EPA's cost evaluation for SCR NOx control, addressing both the capital cost for process equipment and the levelized cost per ton of NOx removed.

Three elements of critique are presented. First, the use of EPA's SCR cost-estimating procedure, as presented in the rulemaking docket, is reviewed and applied to alternative conditions that better reflect the classes of turbines and load ranges in the duty-based subcategories. Second, the combustion turbine NOx emission rate assigned is adjusted to consider the disparate rates from aeroderivative and three different frame designs. Third, EPA's development of SCR capital cost – primarily for simple cycle units – is reviewed and augmented with inputs from recent projects. Fourth, the challenges to retrofit SCR for existing units are described, and cost estimates offered.

Review and Revision of EPA's Procedure

The EPA developed a cost-estimating procedure for SCR to calculate the cost per ton of NOx removed based on inputs such as capital cost, unit capacity factor, and the initial and controlled NOx emissions. This methodology in the rulemaking docket[32] employs SCR capital cost as derived for the NETL[33] by Black & Veatch (B&V). The methodology assumes a unit capacity (as heat throughput), capacity factor, NOx at the combustor exit, and the desired NOx emissions rate. EPA uses these inputs with the methodology to calculate the cost per ton of NOx removed.

The EPA also cites two values of SCR capital cost in the Proposed Rule.[34] Table 7-1 summarizes the SCR costs cited and those reported in the NETL reference.

The costs in Table 7-1, reportedly derived from B&V's experience in designing and operating SCR processes on combustion turbines, are relatively consistent when adjusting for generating capacity (using the "2/3" scaling relationship). Table 7-1 costs are also consistent with the SCR capital requirement cited by the NETL 2023 Cost Study when the role of combustion turbine capacity is defined.

[32] See NETL Detailed Costs SCR Nov 2024 available in Docket ID No. EPA-HQ-2024-0419-0017.

[33] NETL 2023 Cost Study.

[34] 89 Fed. Reg. at 101326, footnote 37.

Table 7-1. SCR Capital cost Per EPA

Reference	Combined Cycle	Simple Cycle
NETL	$6.3 M for 717 MW (~$9/kW)	$5.7M for ~105 MW with attemperation: $25/kW without attemperation: $47/kW
Fed Reg. at footnote 37	~$10/kW for 400 MW	$70/kW for 50 MW
Fed Reg. at 101326	$4-10M for "large" units • $4 M per 100 MW = $40/kW • $10 M for 1,000 MW = $10/kW	$2-4 M for Small/Medium CT (~$40-80/kW)

The capital recovery and fixed and variable operating costs are consistent with conventional practice. The fixed operating and maintenance (O&M) cost, expressed as a percentage of capital, is 3%. The variable O&M is calculated based on reagent and heat rate penalties. The NETL/B&V assumption of an auxiliary load of 0.3% gross, a unit lifetime of 15 years, and a 7% cost of funds is consistent with standard practice.

The EPA's assumed reference generating unit and capacity factor to estimate the levelized cost per ton of NOx for simple cycle and combined cycle units, however, bias control cost to values lower than likely to be observed in commercial practice.

Turbine Frame Classes

A significant shortcoming is EPA's failure to recognize the differences in NOx emissions from various turbine "frame" and aeroderivative designs. Differences in turbine and combustor design result in a range in NOx emissions, ranging from 25 to 5 ppm.

Figure 7-1 depicts the evolution of different combustion turbine frame classes over time.[35] Figure 7-1 highlights the increase in combustion turbine efficiency when operating in combined cycle, and portrays on the horizontal axis the changes in design and materials with the E-Class, F-Class, and H-Class turbines. The use of advanced materials of construction, advanced combustor design, and improved cooling technology enable the use of higher combustor firing temperature, ranging from approximately 1,200ºC for E-Class to as high as 1,600ºC for the H-Class. The evolution to higher firing temperatures – and the implications for NOx – should be considered in EPA's cost evaluation to achieve an SCR-driven NOx rate (e.g. 3 or 4 ppm at 15% O_2).

[35] A Brief History of GE Gas Turbines, Power Magazine, July 8, 2019. Powerhttps://www.powermag.com/a-brief-history-of-ge-gas-turbines-2/.

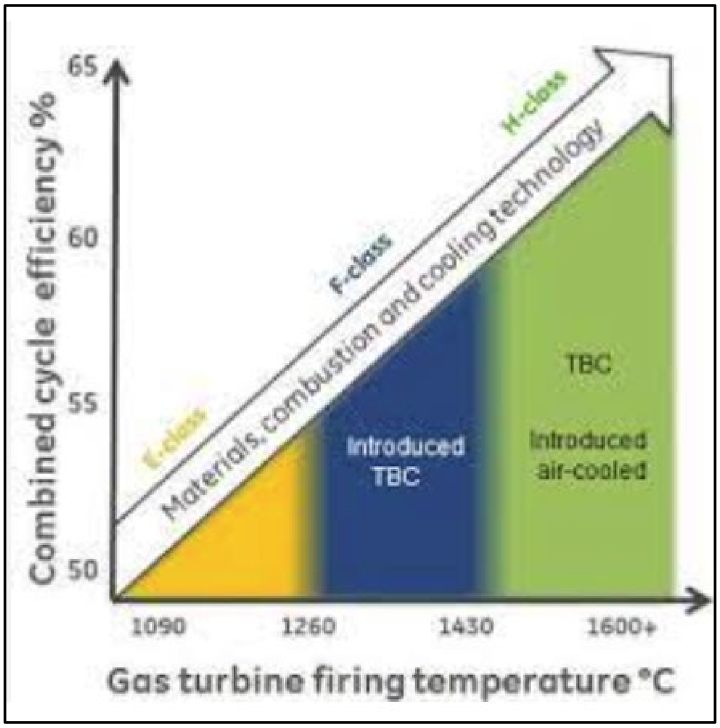

Figure 7-1. Evolution of E, F, and H-Class Frame Engines

The disparity in NOx emission is evident in both the comments submitted by EPRI[36] to this rulemaking and EPA's summary of combustion turbine performance, developed as part of this rulemaking.[37] Both sources show, almost without exception, aeroderivative turbines typically emit 25 ppm. The differences are notable for frame combustion turbines. Using GE designations as an example:

- Larger H or HA frame units (commonly referred to as H-Class) also consistently emit 25 ppm, using DLN.
- F-Class turbines can consistently emit 15 ppm, with some units achieving 9 ppm, depending on the combustor type.
- E-Class turbines engines – depending on the combustor type – generate NOx from as high as 25 and 15 ppm; with some emitting as low as 5 ppm.

A similar pattern is evident in combustion turbines from other suppliers.

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[36] Comments of the Electric Power Research Institute on Environmental Protection Agency EPA-HG-OAR-2014-0128; FRL-5788-02-OAR, Review of New Source Performance standards (NSS) for Stationary Combustion Turbines and Stationary Gas Turbines - Proposed Rule, March 13, 2025.

[37] EPA-HQ-OAR-2024-0419-=0020_attachment_3.

Reference Unit Selection

There are three flaws in EPA's calculation of results using a generic reference unit. These are (a) generating capacity, (b) selection of capacity factor, and (c) failure to recognize the disparate NOx emissions from various combustion turbine "frame" designs. The assumptions for the cost evaluation are revised and updated as follows.

First, EPA selects a reference unit size that minimizes the cost of SCR per unit of generating capacity. Specifically, EPA selects the largest gas turbine available on the market – 4,450 MMBtu/h. Figure 7-2 shows this combustion turbine's heat throughput and capacity at the 99.7th percentile of the population. Indeed, such a large turbine corresponds to the largest H-Class turbines available on the market and likely not representative of the current H-Class turbine population. However, a capacity exceeding 82% of the present inventory, as opposed to 99.7% as projected by EPA, seems more likely. The revised reference case assumes a combustion turbine capacity of 1,780-2,130 MMBtu/h, as exhibited in Figure 7-2, and is adopted for this study.

In addition to altering the reference unit, this study evaluated several classes of frame turbines. Specifically, three reference cases instead of one are evaluated to reflect the substantially different emissions rates from turbines equipped with advanced combustors. Three classes of frame turbines are addressed: (1) H-Class—380 MW, corresponding to 3,420 MMBtu/hr, with a combustion-controls NOx emissions rate of 25 ppm; (2) F-Class—200 MW, corresponding to 1,800 MMBtu/hr, with a combustion-controls NOx emissions rate of 9 ppm; (3) E-Class—88 MW, corresponding to 850 MMBtu/hr, with a combustion-control NOx emissions rate of 5 ppm.

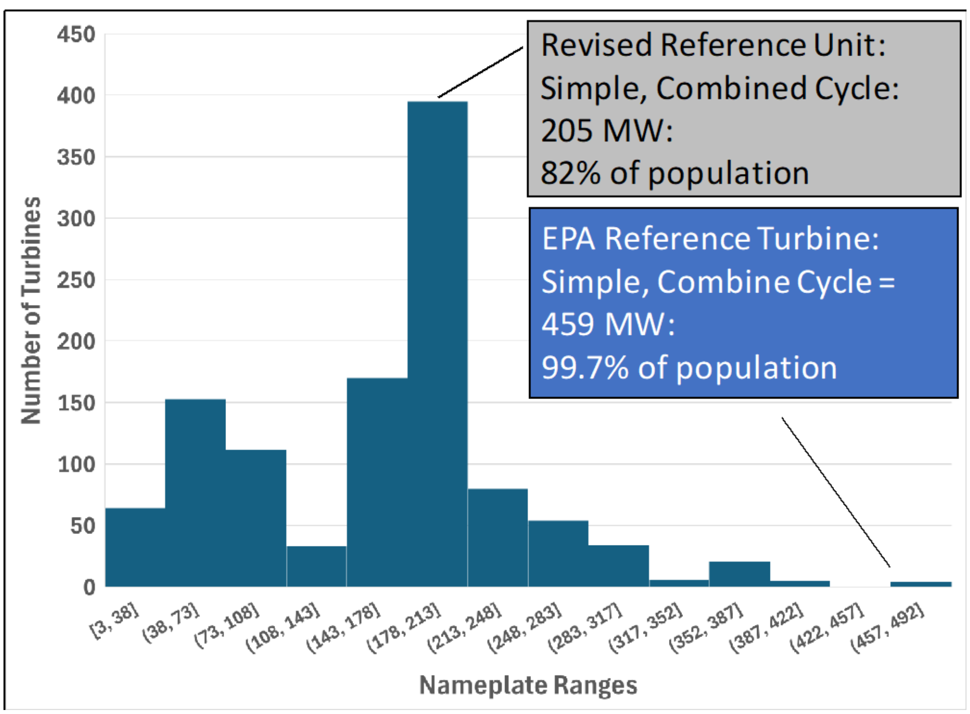

Figure 7-2. Combustion Turbines Population vs Nameplate Capacity

A reference unit of this generating capacity incurs a SCR capital cost determined using EPA's calculation procedure submitted to the rulemaking docket.[38] This procedure for a given heat throughput defines the SCR capital cost and assigns operating cost based in the inlet and outlet NOx emissions. The levelized cost per ton of NOx removed is calculated based on capacity factor. For the revised reference unit of approximately 2,000 MMBtu/h, the normalized cost for SCR is determined as $28/kW for simple cycle and $12/kW for combined cycle, compared to $15/kW for simple and $9/kW for combined cycle for EPA's 4,900 MMBtu/h reference unit.

EPA selected capacity factors for two of the three categories that do not reflect the potential maximum cost. Table 7-2 compares the capacity factor for three categories of operation and the associated turbine cycle considered by EPA: *Low* (Simple Cycle), *Intermediate* (Simple Cycle), and *Base* (Combined Cycle). Capacity factors selected for the purpose of identifying the highest cost per ton should reflect the lowest capacity factor of each category. EPA's selection of capacity factor for the *Low* category of 5% is reasonable (since zero is not realistic). However, the basis for the *Intermediate* category should be corrected from 30% to 20% (the lower end of the Intermediate category range), and for the *Base* category from 60% to 40% (the lower end of the *Base* category range).

Table 7-2. Comparison of Capacity Factors for EPA and Revised Basis

CATEGORY	CYCLE	EPA CAPACITY FACTOR	REVISED CAPACITY FACTOR
Low (<20%)	Simple	5	5
Intermediate (20-40%)	Simple	30	20
Base (>40%)	Combined	60	40

EPA uses NOx emission rates in the calculation that do not reflect the disparity of the four categories of combustion turbines described (aeroderivative, and E- F-, and H-Class turbines).

Cost Evaluation: EPA SCR Cost

A cost evaluation is presented that first replicates EPA's analysis, using EPA's SCR costs but a more realistic generating capacity and capacity factors, as described above, and further evaluates how control cost can vary by combustion turbine frame design.

Table 7-3 summarizes these revised results, showing the levelized cost per ton of NOx removed per turbine class, addressing four scenarios of NOx reduction, for the relevant SCR capital cost and capacity factor.[39] Specifically, the NOx reduction scenarios considered (Column B) are: (a) 25 to 3 ppm (H-class and aeroderivative); (b) 15 to 3 ppm (some F-Class), (c) 9 to 3 ppm (advanced DLN F-Class), and (c) 5 to 3 ppm (Advanced DLN E-Class). For each of these

[38] EPA-HQ-OAR-2024-0419—0017_attachment_1.

[39] The referenced calculation is conducted with the referenced EPA procedure, using the change in NOx emissions and capacity factors as specified.

scenarios, the cost is presented for four cases: Low load (simple cycle), Intermediate load (simple cycle), and Base load (combined cycle). Table 7-3 reports SCR capital cost (Column D) based on EPA's methodology and the capacity factor (Column E) selected for analysis.

Table 7-3. Summary of Revised Cost Evaluation

Column A Fed Reg: 101334	Turbine Class	Column B NOx Δ ppm	Column C GT Design	Column D SCR $/kW	Column E Capacity Factor	Column F $/ton EPA-HQ-OAR-2024-0419-0017 _attachment_1	Column G $/ton (@ 2,000 MBtu/h)
Low (<20%)	H	25 to 3	SC	28	5	18,391	25,011
Intermediate (20-40%)			SC	28	20	4,894	7,899
Base >40%)			CC	12	40	3,545	5,047
Low (<20%)	F	15 to 3	SC	28	5	33,000	45,256
Intermediate (20-40%)			SC	28	20	8,400	13,884
Base >40%)			CC	12	40	3,800	5,732
Low (<20%)	F	9 to 3	SC	28	5	65,000	89,361
Intermediate (20-40%)			SC	28	20	16,000	26,618
Base >40%)			CC	12	40	6,400	10,314
Low (<20%)	E	5 to 3	SC	28	5	190,000	261,761
Intermediate (20-40%)			SC	28	20	42,000	75,553
Base >40%			CC	12	40	16,000	27,272

The cost as determined using EPA's methodology and inputs (Column F) is compared to results (Column G) based on lower heat throughput and associated higher SCR capital (Column D), and capacity factor (Column G). The revised results show higher cost incurred by a factor of 1.5 to 2.

Cost Evaluation: Updated Capital Cost for SCR

The estimates of capital cost used by the EPA – although developed by an experienced engineering firm – do not reflect recent market conditions. The NETL concedes these costs may not reflect evolving market conditions, with the following disclosure:

The results......in this study are not intended to reflect a specific operational model or all the potential market pressures experienced by plants operating today, or the price consumers can expect to pay.[40]

[40] NETL 2023 Cost Study at 4.

Recent experience by combustion turbine owners confirms this observation. Table 7-4 presents a summary of SCR cost estimates acquired by owners for both simple and combined cycle duty. These costs significantly exceed those projected by the NETL.[41]

New Unit

Table 7-4 reports SCR capital cost for new simple cycle units significantly exceed the cost utilized by EPA. Levelized cost per ton of NOx removed is either from a cited reference or calculated using EPA's procedure.

EPA reports but unexplainably dismisses the significant SCR costs for Jack County, estimated on a normalized basis as $25.1/kW, resulting in a cost per ton exceeding $67,000 (even at 29% capacity factor, which is not the low end of the intermediate category range). Further, SCR capital costs solicited by owners for simple cycle units readily exceed EPA's references. The capital for SCR for the 229 MW TVA Colbert unit (and F-Class turbine with a guaranteed advanced DLN rate of 9 ppm) is estimated as $94/kW, which for a capacity factor of 20% translates to almost $50,000 per ton. Equipping the 88 MW TVA Paradise units (E-Class turbines with a guaranteed rate of 5 ppm) with SCR requires almost $300/kW, translating into more than $550,000 per ton for the negligible reduction in NOx (from 5 to 3 ppm) at 20% capacity factor.

SCR estimates for the largest combustion turbines operating in simple cycle also show capital and levelized cost per ton exceeding EPA estimates. Georgia Power's Yates Units 8-10 each are projected to require between $66 and $108/kW for SCR procurement and installation. Levelized cost per ton varies with NOx removed and approaches $20,000 for reductions from 25 to 3 ppm.

Table 7-4. Cost Summary: New Unit SCR Capital Costs

Owner/ Station	**Gas Turbine Capacity (MW), Supplier**	**Capital Cost ($M)**	**Capital Cost $/kW**	**Capacity Factor (%)**	**$/ton (per NOx reduction)**
Jack County[42]	490 (not specified)	32.15	25.1	29	15 -5 ppm: 67,088
TVA Colbert	3 x 229 (GE 7F.05)	65	94.1	20	9-3 ppm: 48,635
TVA Paradise	88 (GE 7E.03)	26.3	298	20	5-3 ppm: 551,000
GA Power Yates 8-10	453 Mitsubishi 501JC	30-47	66-108	20	25-3 ppm: 13,337-19,275

[41] Ibid.

[42] EPA-HQ—OAR-2024-0419-0020_attachment_1. See worksheet "Permit Detailed Costs."

Retrofit

Retrofitting SCR into either a simple or combined cycle unit presents challenges in creating the necessary space to provide the process conditions described in Section 6. For this reason, the retrofit of SCR is an unrealistic option for existing units, and would be much costlier (on a $/kW basis) than for new combustion turbines.

Simple Cycle

Figure 7-3 is a satellite image of a typical F-Class simple cycle combustion turbine equipped with SCR, demonstrating the space required and relative location of the SCR. Simple cycle units not initially configured for SCR usually do not have adequate "footprint" for ductwork, as the turbine exit is typically close-coupled to the stack to minimize ductwork and gas pressure drop.

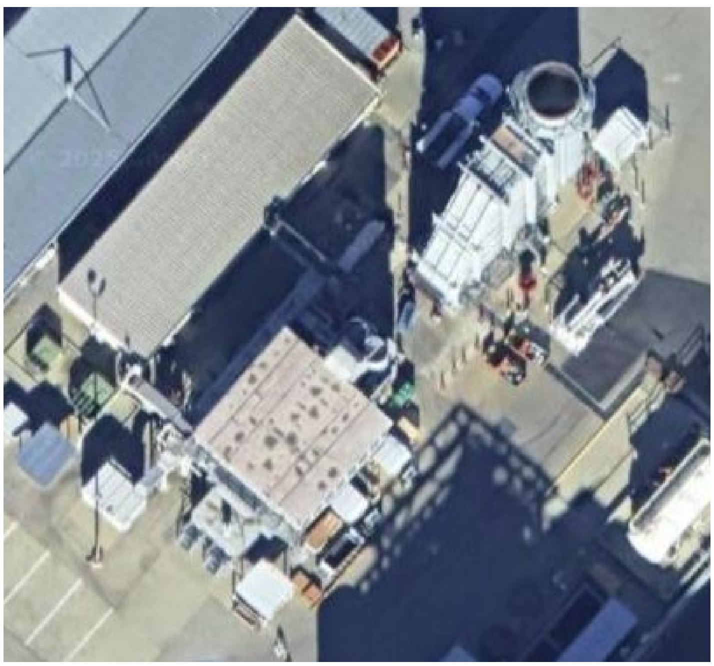

Figure 7-3. Salt River Project Ocotillo Simple Cycle Unit Equipped with SCR

The retrofit of such process equipment will require either relocating the stack or configuring the SCR reactor in a parallel duct or "sidecar" concept. Either of these adds gas pressure drop and create a tortuous path for gas flow, making it difficult to achieve a uniform gas flow distribution at the catalyst inlet. To achieve high NOx removal relocating the stack and maintaining a simple gas flow are needed. The associated costs make this unrealistic.

Table 7-5 summarizes retrofit SCR cost reported by two owners, and levelized cost per ton (calculated using EPA's procedure). One Midwestern owner of 450-500 MW combustion turbines engaged a third-party engineering firm to evaluate retrofit design and cost for two units. The equipment suppliers' bid and installation cost equate to $35-55 million for a complete "turnkey" installation a single unit, representing a normalized capita cost of $76-120/kW. Based on a capacity factor of 20%, an assumed H-Class design, and the 25-ppm combustor NOx, the levelized cost per NOx ton removed can exceed $20,000 (for reduction to 3 ppm).

Table 7-5. Retrofit SCR Cost Evaluation: Simple Cycle Units

Owner/ Station	Gas Turbine Capacity (MW), or Supplier/Frame	Capital Cost ($M)	Capital Cost $/kW	Capacity Factor (%)	$/ton (per NOx reduction)
Midwestern Owner	450-500	35-55	76-120	20	25-3 ppm: 15,112-22,051
Consumers Energy Company (Zeeland)	GE 7 FA	66.8	322	20	9-3 ppm: 201,830

Similarly, an engineering study for Consumers Energy Zeeland Station addressed the design and cost to retrofit SCR to a GE-7 FA Frame unit.[43] The projected capital charge equates to $322/kW, with the publicly reported cost per ton as $40,366 per ton for a 100% capacity factor[44] (implying approximately $200,000 per ton for 20% capacity factor).

Combined Cycle

Retrofitting an SCR into a combined cycle unit similarly requires providing for adequate space for catalyst installation and well-controlled process conditions.

Figure 7-4 presents a schematic view of a heat recovery steam generator configured for SCR. This figure shows approximately 13 feet of process equipment is needed.

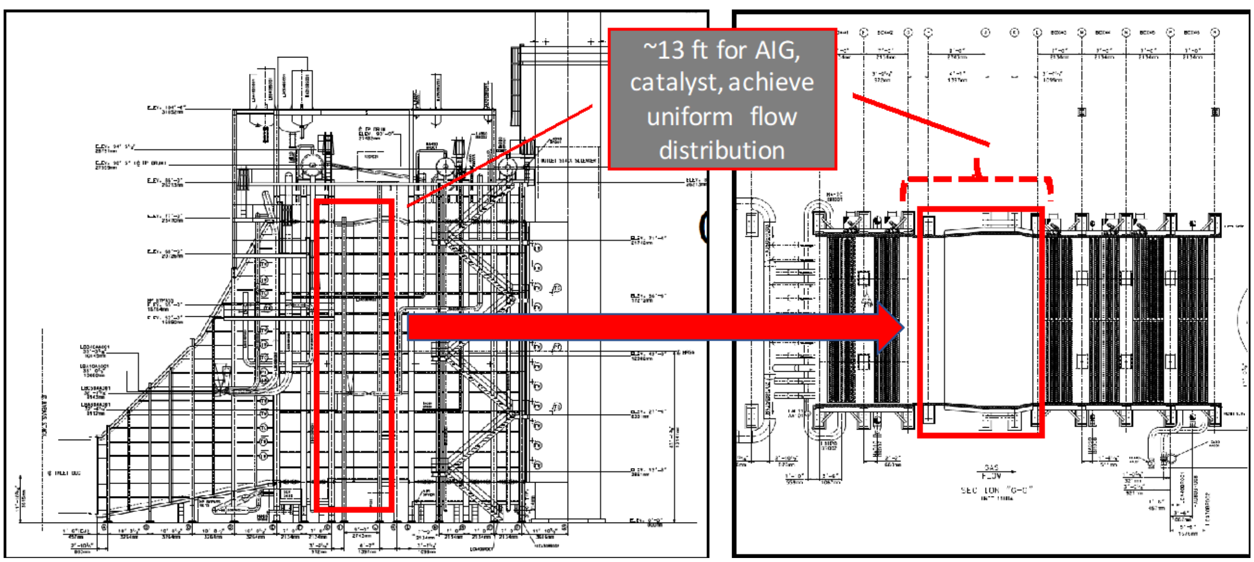

Figure 7-4. Sectional Drawing: HRSG Design to Accommodate SCR

[43] *Technical Support Document Permit to Install Application Covering a Proposed Modification of the Zeeland Generating Station*, Prepared for Consumers Energy Company, April, 2024.
[44] Ibid. Appendix C at 108.

Most notably, the spacing between the first and second tube bundles is defined as the only option to locate the necessary SCR process conditions.

Figure 7-5 presents an engineering sectional view of the HRSG for the existing Jackson Generating Station[45] in Michigan. Two means were explored to retrofit SCR. First, the conventional approach of modifying the HRSG to accommodate SCR process equipment was evaluated. The SCR process design identified 11.5 feet as required, which is not feasible as the existing arrangement provides approximately 3 feet. Removing steam tubes could expand the footprint to 11 feet, but this would reduce the output and thermal efficiency of generation.

The second approach considered was to uniquely attempt to retrofit an SCR catalyst into the HRSG's expansion ductwork. This action—never attempted commercially—was abandoned due to the inability to rectify the highly turbulent gas flow into a well-behaved uniform flow pattern and inject reagent to achieve the desired mixing uniformity.

Costs were not developed for either approach as the technical feasibility was judged inadequate for a commercial venture.

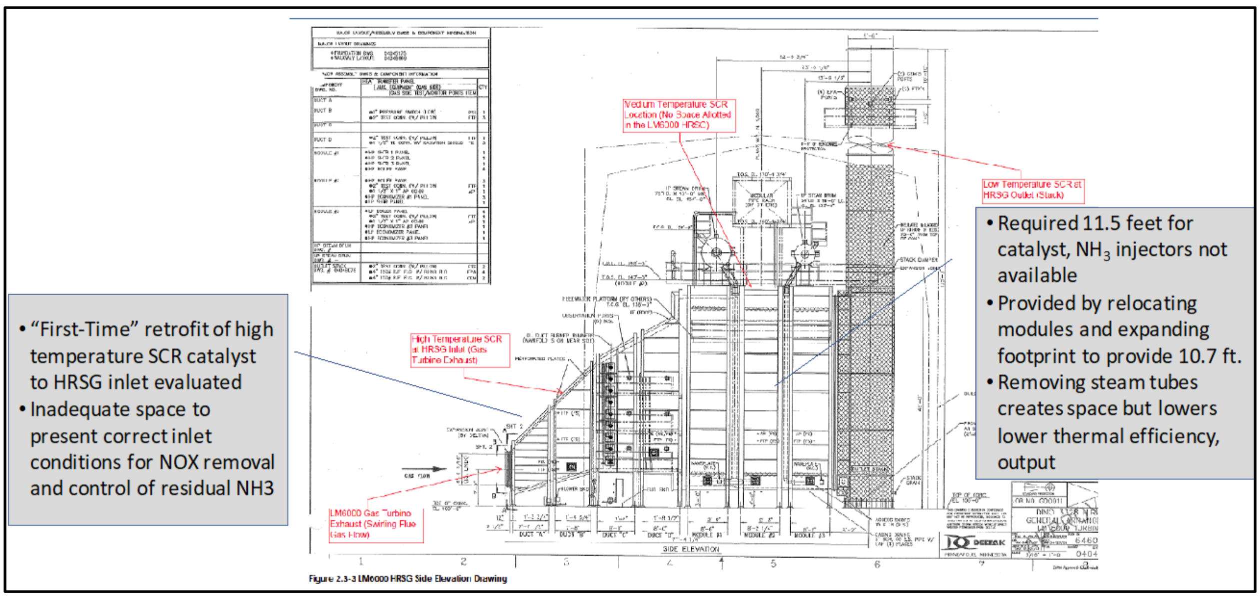

Figure 7-5. Jackson Unit: Options to Retrofit SCR

Observations are summarized as follows:

- EPA's selection of reference units is flawed. EPA selected the generic reference unit at almost the largest capacity available, biasing SCR cost per unit capacity low. EPA also selected capacity factors for two of the three categories of operation that do not reflect the

[45] *Technical Support Document: Permit to Install Application Covering a Proposed Modification of the Jackson Generating Station*, Jackson County, Michigan. Prepared for Consumers Power, June 2018.

highest cost. Further, the reference unit does not reflect the widely divergent NOx emissions of the four different classes of turbines.

- These shortcomings are addressed by replicating EPA's calculations using a more realistic capacity of 2,000 MMBtu, lower capacity factors that reflect the low end of the range of each duty-based subcategory (per Table 6-1), and conducting the cost per tom calculations for a range of combustor exit NOx emissions. Revised results show EPA underpredicting the cost per ton for NOx removed by 50 to 100%.

- A more notable shortcoming is EPA ignoring the divergent NOx emissions from the turbine categories of aeroderivative, E-Class F-Class, and H-Class. Updating EPA's calculations for simple cycle duty and considering NOx emissions ranging from 25 ppm to as low as 9 and 5 ppm show estimated cost ranges from $25,000 to exceeding $200,000 per ton of NOx.

- EPA's estimates of SCR capital cost for new combustion turbines are dated and not relevant in the present market. Recent estimates of SCR capital show significantly higher cost. The normalized cost ($/kW) estimates for combustion turbines of 229-450 MW (F-Class and H-Class frame turbines) range from $66 to more than $100/kW; one case for an 88 MW unit (E-Class frame turbines) projected cost approaching $300/kW. This elevated capital cost, combined with lower combustor NOx emission rates, elevates the levelized cost per ton that (with the exception of a 25-ppm combustor rate) ranges from $50,000 per ton to over $500,000 per ton.

- The space required for an SCR reactor within the footprint of an existing simple cycle unit is not available without major changes to the unit. Cost estimates to retrofit SCR to existing units are similarly elevated; for two examples, capital costs ranged from approximately $100/kW to $300/kW. Depending on the combustion NOx rate and capacity factor, the levelized cost per ton is more than $20,000 and can exceed several hundreds of thousand dollars.

- The retrofit of SCR to an existing combined cycle unit HRSG that is not designed to accommodate the necessary process conditions is not technically feasible. The space required to (a) correct gas maldistribution from the gas turbine exit, (b) inject NH_3 and mix with gas to high uniformity, and (c) lower gas velocity to ~15-20 actual ft/sec for to achieve proper residence time and minimize pressure drop is not available without significant modification to the HRSG.

SECTION 8. UPGRADES AFFECTING HOURLY EMISSIONS RATE

The EPA in addressing potential modification to combustion turbines states:

If an owner/operator replaces a combustor with another version with the same ratings as the previous combustor, such that the emission rate to the atmosphere of NOx or SO2 is not increased, the combustion turbine would not trigger the NSPS modification criteria. The EPA is soliciting comment on whether there are other actions that could increase the potential hourly emissions rate of a combustion turbine and thus may constitute ''modifications'' and whether any unique considerations exist for this subcategory.….

EPA rightly recognizes the environmental benefits of upgrading a combustor. Almost without exception, NOx emissions decrease subsequent such an upgrade; the dry low NOx combustor designs employ advanced means of mixing fuel and air to control flame temperature. A combustor upgrade, as part of changes associated with a "hot gas path upgrade" can also increase the thermal efficiency of power generation. These benefits serve to justify not considering this change as a basis to trigger NSPS.

EPA solicits input on other actions that could potentially increase hourly output. Two actions can each increase air flow to exploit the upgrade to the hot gas path and not contribute to an increase in emissions. Specifically, both a compressor upgrade[46] and retrofit of high flow inner guide vanes[47] can increase the air flow. If contemporaneously retrofit with a combustor upgrade these are still aspects of upgrades that contribute to lower NOx emissions. Further, emissions of SO_2 may not necessarily increase, depending on the increase in combustion turbine thermal efficiency.

In summary, actions to increase combustion turbine airflow will not necessarily increase NOx and SO_2 emission, and trigger NSPS, when deployed with a combustor upgrade.

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[46] . https://www.psm.com/retrofits-and-upgrades/gas-turbine-optimization-package-and-combustion-upgrade-packages.

[47] Phillips, J. et. al., Gas Turbine Performance Upgrade Options. Available at https://static1.squarespace.com/static/5b08345b1aef1d82050969af/t/5b1abfb70e2e7242ed7ce0f3/1528479672115/gt_upgrade_options.pdf.