ICAC

August 8, 2023

TO: Environmental Protection Agency
FR: The Institute of Clean Air Companies
RE: Docket ID NO. EPA–HQ–OAR–2023–0072

The Institute of Clean Air Companies (ICAC) appreciates the opportunity to offer comments in response to Environmental Protection Agency's proposed rulemaking on New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule.

ICAC is the national trade association of companies that supply greenhouse gas management and air pollution control and monitoring systems, and equipment and services for stationary sources. For over 60 years, ICAC member companies have helped to clean the air by developing and installing reliable and cost-effective control and monitoring systems. ICAC supports technology-neutral and flexible policies that enable cost-competitiveness and a diverse set of technologies to compete in the market.

ICAC's comments will focus on the constraints on cost-effective technology solutions, MWh capacity, permitting and financing concerns and the market imbalance the rule will create by not including corresponding regulatory requirements for reciprocating engine technology.

Again, ICAC appreciates the opportunity to offer input to EPA and we look forward to answering any further questions or providing additional information.

Best regards,

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1. ICAC BACKGROUND & OVERVIEW

ICAC is a national trade association of companies that supply greenhouse gas management, air pollution control and monitoring systems, equipment, and services for stationary sources, including utilities. For over 60 years, ICAC member companies have developed, commercialized, and installed reliable, cost-effective control and monitoring systems. This extensive experience in deployment of proven technologies directly informs our views relating to our customers being able to deliver clean, reliable, and cost-effective power generation.

ICAC understands that technology innovation addressing regulatory compliance can be an uneven and unpredictable process, with climate change demanding rapid deployment of decarbonizing technologies. However, ICAC believes policies should be technology-neutral, flexible and enable cost-competitiveness.   Policies should allow for a diverse set of technologies to compete in the market which may include carbon capture and removal, hydrogen as a fuel, as well as fuel alternatives such as biomass and ammonia.

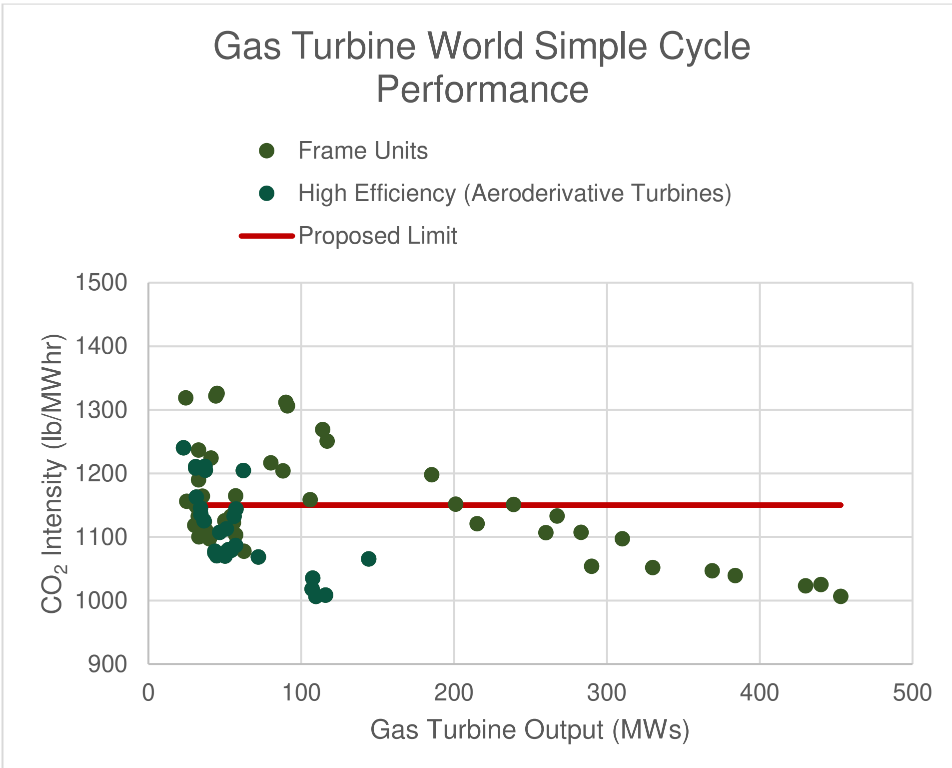
ICAC understands that the proposed rule presents both challenges and opportunities in today's energy market and its transition to a decarbonized market. However, ICAC is concerned that as drafted, the rule might increase emissions through curtailment of large efficient combined cycle units favoring utilizing less efficient simple cycle combustion turbines.

ICAC foresees that the biggest challenge in implementing the rule will be the timelines for investment corresponding with production tax credits in the Inflation Reduction Act (IRA) of 2022. This may inadvertently strand investment in both existing and future projects. The identified compliance strategies will be very challenging, not only because of technical aspects, but the ability to permit projects such as pipelines to support will likely be the largest obstacle. Furthermore, to help add some consistency, we urge EPA to consider aligning definitions with those in the IRA.

2. CONSTRAINS COST-EFFECTIVE TECHNOLOGY SOLUTIONS

ICAC believes that the new proposed unit lb CO_2/MW-hr gross requirement of 1150 for new stationary combustion turbines having to operate more than 20% capacity factor will eliminate many of the current cost-effective generation technologies. In addition, integrating site-specific conditions, part-load operations, and start-ups of the combustion turbines will eliminate many of the current turbine product offerings from consideration. Reference Figure 1 below identifies current models and performance.

Figure 1. Gas Turbine World Gas Turbine (Simple Cycle) Performance



Source: Gas Turbine Association

- Figure 1. Depicts CO_2 emission intensity as calculated based on the GTW quoted performance compared to gas turbine output. The red horizontal line represents the proposed emission standard for the Intermediate Category of gas turbines. The green markers represent frame style units while the yellow markers represent "highly efficient" gas turbine units. The "highly efficient" gas turbine units are assumed to represent aeroderivative turbine technology.
- As the name applies, aeroderivative turbines are gas turbine aircraft engines that have been repacked to provide ground base generation. Aeroderivative turbines have the advantage of being the fastest starting units and tend to be more efficient than similar sized frame units. Aeroderivative units are designed for high reliability and low weight and tend to be more expensive.

Some aeroderivative and advanced class combustion turbines will be able to achieve the draft regulatory levels. Unfortunately, the independent system operators will be unable to dispatch many of these machines for load following and part-load operations because they will be unable to achieve the required CO_2 intensity. This situation will force the industry not to leverage the reliability and resiliency of new modern turbines, but to instead rely on older coal and simple cycle units in the grid system operator region. Relying on simple cycle units to achieve ISO conditions may sound plausible, but unfortunately the impact from environmental conditions (especially temperature) and part-load conditions result in significant deratings of emissions performance capabilities.

3. How to deal with 'missing' MWh

Based on 2022 EIP data, natural gas combined cycle power plants achieved an average 56.6% capacity factor in the U.S. power system. They enjoy a significant efficiency gain through exhaust flue gas heat recovery of the combustion turbine. Limiting the existing plant capacity factor to 50% means that over 163 million MWh will need to be replaced within the electrical grid. Some of this capacity will be supplied by wind, solar and battery energy storage systems, but the vast majority will still need to achieve reliability and resilience of supply leading to replacement primarily with simple cycle combustion turbines. Using the NSPS limit of 20% capacity factor, this is equivalent to 93 GW of new generation. Based on current capital costs, this represents up to an additional $100 billion of capital investment with the only significant benefit being additional dispatchable MW capacity on the system.

Unfortunately, utilizing this simple cycle combustion turbine technology forgoes the already installed and more efficient capacity currently within the natural gas combustion turbine combined cycle fleet. If implemented, it will likely lead to higher overall CO_2 emissions within the natural gas fossil fuel generation fleet.

4. Timelines and incentives

The timelines for investment and production tax credits in the IRA of 2022 are not well timed or coordinated with the draft EPA NSPS rulemaking requirements. This adds to the difficulty in further developing the carbon capture and hydrogen infrastructure.

<u>Carbon Capture for New Combined Cycle Facilities</u>

The proposed rule identifies 2035 as a compliance date to install and operate carbon capture on baseload turbines. The incentives for carbon capture provided by the Inflation Reduction Act expire in 2032 for all projects that have not begun construction. Potentially, the intent was to start construction by 2032 (as required in the IRA) for 2035 capacity additions. Unfortunately, common project challenges experienced on most projects include risks such as air permitting delays, Class VI injection wells, CO_2 pipelines, natural gas lateral pipelines, water permits and potential for Justice 40 issues. This could easily delay the project outside of the IRA production tax credit window, effectively stranding any investment in the project. The proposed rule will not only require carbon capture technologies to scale and deploy at a vastly accelerated rate, but also amplify the underlying infrastructure requirements and value chain complexity, posing a significant risk to the broad financing and implementation of carbon capture alongside baseload turbines. The availability of centrally managed CO_2 infrastructure, such as CO_2 compression, as well as rigorous standards around gas composition and safety are required to alleviate that risk.

The IRA also has an end date for the production tax credit of 12 years after the facility is commercial. Financing for these mega-projects has traditionally been 15-20 years. These projects carry the risk of the asset being financially stranded if needing to compete against other existing combined cycle power plants without the added burden of lost auxiliary power and the cost for CO_2 disposal.

Hydrogen Availability

For a significant amount of generation to employ the hydrogen fuel compliance strategy, the quantity of hydrogen produced in the U.S. would be required to grow exponentially between 2032 and 2038. If the capacity is not entirely realized in this timeframe, then the asset would be curtailed at the amount of available hydrogen.

While 2032 sounds like a long time into the future, it is tomorrow in terms of project development and permitting. This urgency is compounded by the time required in getting the EPA NSPS rule published as finalized followed by approximately two additional years to complete state implementation plans. That extends the timeline to 2026 for an early project financial close. Considering the 2032 date means January 1, 2032, this limits the entire project execution period to just five years. While 60 months may seem like an achievable period, permitting is a massive risk issue and is seemingly more constrained every year through additional regulatory actions and processes.

The IRA also has an end date for the production tax credit of 12 years after the hydrogen facility is commercial. At this point, the subsidized fuel cost will end, and the project will have to bear this added fuel costs competing against other existing facilities without the constraint of using hydrogen. The risk of a stranded asset after 12 years is a very real threat that will not be accepted by the traditional financial community within the U.S. market.

We believe the proposed timelines of 2032 and 2038 for 30% and 96% H_2 availability are not realistic. This challenge is not a technology issue, but rather a H_2 supply/infrastructure development gap. While there is a significant amount of money and emphasis being placed on this development with IRA and other programs, there are still many hurdles that must be overcome. Hydrogen infrastructure development is still in its infancy. Without any consideration of uses beyond projections for power plant usage, to meet the 30% H_2 goal for units >300 MW and an average capacity factor of ~50% (assuming maybe half of the units choose to utilize H_2 rather than install CCUS), an estimated 2.3 million tons H_2 will need to be available and 25 GW of electrolyzers. Additionally, there needs to be H_2 & CO_2 storage in place, H_2 & CO_2 pipelines, and electrical grid upgrades. This consideration precludes any use in the transportation or other sectors which are also looking at H_2 for energy storage and use, and any shifts in policies/politics in coming years which might impact implementation. These timeframes need to be closely analyzed with eyes on the above factors and others and synched up with the Department of Energy and other government agencies to set a reasonably achievable time frame.

Further, the availability of "green hydrogen" that meets the requirement of 0.45 g CO_2/g H_2 carbon intensity will be extremely difficult to meet as this rule requires. It is one thing to require co-combustion of hydrogen but another to require that all the hydrogen come from the least carbon-intensely made hydrogen. This constraint limits the source of the hydrogen, which will make it even that much more difficult to meet the 30 and 96% co-combustion requirements by 2032 and 2038.

Replacement Capacity

The "Missing MWh" capacity identified in Section 3 strains the utility industry further by adding additional capacity requirements already facing an unprecedented expansion of electrical load in the U.S. market. Adding just 60% of the MWh capacity identified in Section 3 will be almost 56 GW of new capacity costing more than $61 billion. These capacity additions by utilities due to establishing limits on current natural gas combined cycle unit capacity factors would only be realized after the final rule is published in the federal register and an additional two years to finalize state implementation plans. With a compliance date of 2035, utilities would likely implement those projects replacing this lost capacity in the 2032-2034 timeframe. Under these likely conditions, restricting the existing combined cycle fleet to 50% capacity factor would require investment of over $20 billion (not inflation adjusted) for each of the three years prior to 2035.

5. 'Chicken and Egg' Permitting and Financing Dilemmas

Throughout much of the world, higher risk mega-projects are financed either through large Chinese government-owned companies or through government backstopped Korean and Japanese companies. These have been the primary entities willing to bear the significant financial risks of multi-billion-dollar projects. However, here in the U.S., power producers face permitting and financing challenges.

Permitting Dilemma

A natural gas combined cycle project with carbon capture is going to have separate permitting for the combined cycle plant, permitting for the CO_2 pipeline and permitting for the injection well. No project is going to receive financing without first recognizing each of these project aspects will be successful. Additional governance capacity is likely required to meet the accelerated permitting needs of attaching carbon capture to combined cycle plants.

A hydrogen-supplied combined cycle project has the added risk of separately permitting the hydrogen production facility, pipeline, and hydrogen storage facilities. Co-locating these facilities could be a viable strategy, but it would defeat the DOE goal of operating these as a multi-faceted hydrogen hub. Without a hub configuration, large hydrogen production facilities would risk having only a single hydrogen demand user in which market forces could also impact hydrogen fuel utilization.

Financing Dilemma

The contracting for a natural gas combined cycle project with carbon capture is likely to have individual contracts, each with separate performance and financial guarantees. This approach would include a contract for the combined cycle island, potentially a separate contract for the carbon capture island, a contract for the pipeline and contract for geological sequestration. Most project developing entities are unlikely to have the financial capacity to absorb the risk from a failure of one contractual aspect of a project. Again, this is where the government backed companies or government support companies commonly carry the risk.

A hydrogen-supplied combustion turbine combined cycle facility has a separate dilemma facing hydrogen supply. The facility would start running on a 30% by volume hydrogen blend and then ramp to the 97% requirement by 2038. If the hydrogen fuel cost subsidized by the IRA is slightly higher than natural gas, the project will likely only burn the minimum required quantity for compliance. Most of the capacity that could be subsidized by the IRA is not needed until closer to 2038. Unfortunately, that added capacity would not qualify and receive a hydrogen fuel subsidy. The hydrogen-supplied combined cycle would have to compete with other system resources not constrained by similarly high costs for fuel. This competitive situation creates a significant challenge in financing this approach if you are unsure if there will be any future legislative support to subsidized hydrogen fuel in the six-year ramp up in production. A developer would not build the additional capacity up front as they would not have any opportunity to produce the hydrogen required to take advantage of the production tax credit.

6. UTILITY CAPITAL CONSTRAINTS SEVERELY LIMIT GENERATION STRATEGIES

Utilities are currently faced with many challenges including electrification of the vehicle fleet, EPA rulemaking intended to limit utilization of fossil fuels for power generation, massive new data center and crypto-mining electrical loads, transmission, and distribution system expansion, building renewable generation, smart-metering, and commercial/residential building electrification. Utilities must prioritize their capital to maintain affordability, reliability, and resilience in order to protect those least fortunate in society.

Unlike the oil and gas sector which has tens of billions in self-financed risk managed projects, the utility industry is starkly different in comparison. The diverse types of utilities have different challenges in financing their projects which require billions of dollars in capital.

Investor-Owned Utilities

There are investor-owned utilities (IOU) with monopolies within their service territories. Regulatory oversight of the company is typically by a state Public Utility Commission

(PUC) with appointment by the governor, legislature or through elections. These regulated utilities are allowed to generate a rate of return on their investments based on high-quality diligence and performance. They are, however, many times penalized for perceived shortcomings in performance by their PUC, thus limiting financial returns. If the credit rating of the utility drops, then financing costs that are passed onto the consumer increase. Thus, a delicate balance is typically maintained in investment grade credit rating just above junk bond status.

Utilities and their investors target a reasonable growth model of capital deployment for projects. Much of this growth has been incremental investments in transmission, distribution and adding significant renewable generation resources. There are likely less than twenty IOU utilities in the U.S. that could even get financing for a $2.5 billion combined cycle with carbon capture facility. The ability to integrate into the rate base additional multi-billion dollar generation projects is simply too much for a PUC to accept. This leads to the only option for new combined cycle generation being power purchase agreements with independent power producers.

<u>Independent Power Producers (IPP)</u>

IPPs are motivated through financial returns for their investors. This incremental return is integrated into the costs of their power supply contracts. The IPP projects can be greatly constrained by the "chicken and egg" issues discussed in Section 5 of these comments. Comprehensive project risk must be identified and mitigated.

There are only several contractors in the U.S. market that can even perform an Engineering, Procurement and Construction (EPC) contract for a $2.5 billion combined cycle with carbon capture facility. Around the world, much of this risk has been managed through Chinese, Korean and Japanese EPC firms. Even if an IPP did manage to successfully engage an EPC, the project still carries significant permitting risk for pipeline, enhanced oil recovery injection or Class VI geological sequestration. If a significant issue with any of these aspects were to develop, it would risk financially stranding the generation asset. Projects with this level of risk around the world are typically performed either mega-sized oil and gas corporations or sovereign government backed efforts.

<u>Public Power</u>

Public power includes utilities owned by federal, state, and municipal governments. They are efficiently governed as there is no risk of conflict between the investment community and the PUC. As a non-profit entity, any financial commitments are passed on directly to the ratepayers through increased rates. With the potential exception of Tennessee Valley Authority as a federal entity, none of these utilities could maintain their current credit ratings with a $2.5 billion combined cycle with carbon capture facility supplying a minority of their generation needs. Thus, the only real option would be engaging an IPP through a power purchase agreement.

Cooperatives

The generation and transmission cooperatives are similar to public power. Only several would have the financial capacity to maintain their current credit ratings with a $2.5 billion combined cycle with carbon capture facility. Again, the only real option for vast majority of cooperatives would be engaging in an IPP through a power purchase agreement.

7. RECIPROCATING ENGINES

The proposed rule is applicable to steam generation and combustion turbine units but not reciprocating engines. Yet there are numerous facilities in the U.S. consisting of multiple reciprocating internal combustion engines with a generation capacity of more than 100 MWs. Per Wartsila's Website[1], the Wartsila fleet of reciprocating engines includes 76 GWs of installed capacity globally. Of that global capacity, this includes at least 1.8 GWs of generation in the U.S. at 13 plants with an average capacity of 140 MWs. The proposed regulation would impose a burden on gas turbines regarding capacity restrictions, efficiency standards and conversion to H_2 firing and CCS, with no corresponding regulatory requirements for reciprocating engine technology. This creates an imbalanced regulatory burden on these two competing technologies leading to the potential unintended consequence that shifts the market towards large reciprocating installations to circumvent this regulation. EPA should resolve this regulatory imbalance between generation technologies.

8. CONCLUSIONS

ICAC believes that the proposed NSPS draft has integral key challenges that will impact power grid reliability, limit investment in key energy projects and challenge the period of energy transition to decarbonized generation.

Cost constraints in conjunction with the misalignment of IRA funding opportunities threaten stranded investment in multibillion-dollar projects. Projects also face significant permitting challenges. With low-carbon intensity hydrogen infrastructure is still in its infancy, immediate and long-term solutions are limited by additional investment surrounding H_2 storage, CO_2 storage, H_2 pipelines, CO_2 pipelines, and electrical grid upgrades to support production.

[1] https://www.wartsila.com/energy/learn-more/references?region=north-america-caribbean&application=Flexible-baseload

The growing desire for clean energy will require billions of investment dollars even prior to addressing 2035 goals. The magnitude of this required investment will be a challenge for all but the largest investor-owned utilities, co-ops, public power, and municipalities. Outside of large, foreign government entity investment, the independent power producers will be challenged in financial project pro forma to accomplish both NSPS compliance and to achieve the needed long term returns their investment.

ICAC members are proud of their role in helping to deliver the most innovative yet accomplishable clean energy solutions for the power generation industry. Our members are committed to leveraging our technologies to help the industry overcome challenges. Decarbonization goals are only going to be accomplished through support from an active market of companies making significant investments focused on power grid reliability and resiliency.

ICAC would like to thank EPA for the opportunity to respond to this proposed rulemaking. We welcome an opportunity to further discuss these thoughts with you and are happy to answer additional questions or clarify any points made.