August 8, 2023

U.S. Environmental Protection Agency
Docket ID No. EPA-HQ-OAR-2023-0072
[Submitted electronically through www.regulations.gov]

Re: Proposed New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units (EGUs); Emission Guidelines (EG) for GHG Emissions From Existing Fossil Fuel-Fired EGUs; and Repeal of the Affordable Clean Energy Rule

Dear Mr. Fellner:

The Texas Commission on Environmental Quality (TCEQ) and the Railroad Commission of Texas (RRC) appreciate the opportunity to comment on the EPA's proposed NSPS for GHG Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired EGUs; EG for GHG Emissions from Existing Fossil Fuel-Fired EGUs; and Repeal of the Affordable Clean Energy Rule. Detailed comments on the proposal are enclosed. If there are any questions concerning TCEQ's and RRC's comments, please contact James Nolan, Technical Specialist in the Office of Air, at 512-239-2104 or james.nolan@tceq.texas.gov.

Sincerely,

K Keel

Kelly Keel
Interim Executive Director
Texas Commission on Environmental Quality

Wei Wang
Executive Director
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Enclosure

COMMENTS ON THE U.S. ENVIRONMENTAL PROTECTION AGENCY'S (EPA'S) PROPOSED NEW SOURCE PERFORMANCE STANDARDS (NSPS) FOR GREENHOUSE GAS (GHG) EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS (EGUS); EMISSION GUIDELINES (EG) FOR GHG EMISSIONS FROM EXISTING FOSSIL FUEL-FIRED EGUS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE

I. SUMMARY

On May 23, 2023, EPA proposed five separate actions under section 111 of the federal Clean Air Act (FCAA) addressing GHG emissions from fossil fuel-fired EGUs.

EPA is proposing revised NSPS for GHG emissions from new fossil fuel fired stationary combustion turbine EGUs and for GHG emissions from fossil fuel-fired steam generating units that undertake a modification. EPA is also proposing EG for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Additionally, EPA is proposing EG for GHG emissions from existing stationary combustion turbines. Finally, EPA is proposing to repeal the Affordable Clean Energy (ACE) Rule.

The proposed NSPS under FCAA §111(b) target reducing emissions of GHGs from sources that commence construction, modification, or reconstruction after May 23, 2023. These proposed standards of performance will revise 40 Code of Federal Regulations (CFR) Part 60, Subpart TTTT (NSPS TTTT) and create a new subpart, 40 CFR Part 60, Subpart TTTTa (NSPS TTTTa). The proposed EG under FCAA §111(d) would limit GHG emissions from existing sources built on or before May 23, 2023. The proposed EG for existing units will be in a new subpart, 40 CFR Part 60, Subpart UUUUb (EG UUUUb).

The Texas Commission on Environmental Quality (TCEQ) and the Railroad Commission of Texas (RRC) provide the following comments on the proposed rule. Where comments are noted by TCEQ throughout this document, the comment reflects the views of both TCEQ and RRC.

II. COMMENTS

A. General

EPA's proposed new and amended rules place electric reliability at risk and have not considered all environmental effects, which may outweigh the intended benefits of this proposal when considering collateral emissions increases, reduced efficiency, and the additional infrastructure that is necessary for implementation.

TCEQ and RRC oppose the proposed rules. The likely outcome of the proposed rules is the elimination of coal-fired units and a reduced ability to operate natural-gas fired units that currently ensure the availability of reliable electric power. The trend towards increased use of natural gas fuel as a substitute or alternative for coal has been yielding benefits for GHG emissions reduction and progress or maintenance of attainment with National Ambient Air Quality Standards (NAAQS). The proposed rules include control strategies that could negate this trend and potentially result in collateral emissions increases of criteria pollutants, such as ozone.

As noted by EPA in the preamble to the proposed rule, fossil fuel-fired generation declined from approximately 70 percent of total net generation to approximately 60 percent between 2010 and 2021, with coal generation dropping from 46 percent to 23 percent of net generation during the same period. 88 FR 33256. EPA also stated that there have been "…no new coal-fired steam generating units commencing construction in more than a decade." Id. This shows that fossil fuel-fired power generation is already decreasing at an aggressive rate and additional EPA regulations are not warranted since the economics will drive power generation toward renewable energies as they become more cost effective and more widely available on the market. In addition, as stated by EPA in the preamble, the Inflation Reduction Act (IRA) provides tax credits for capturing and storing carbon dioxide (CO_2), which EPA believes will provide an incentive for the power sector to apply carbon capture and sequestration (CCS). Id. at 33245. If these tax credits are successful as an effective incentive, this further calls into question whether the proposed regulations are necessary since existing market forces and policies will continue to reduce GHG emissions from the power industry. The proposed regulation is unnecessary and creates a regulatory burden on the regulated industry, regulatory agencies, and permitting authorities.

EPA's analysis of the proposed rules fails to demonstrate that the proposed standards for power plants would achieve quantifiable or measurable benefits in global atmospheric concentrations of GHGs or in mitigating the effects of climate change. EPA estimated the monetized benefits from the proposed GHG standards through calculations based on the social cost of CO_2 (SC-CO_2), which Texas and numerous other states have challenged as an unreliable and highly speculative metric. In the preamble, EPA acknowledges that the current SC-CO_2 estimates have a number of limitations, including but not limited to outdated modeling assumptions. Id. at 33411. The proposed rule may have unequitable consequences by imposing major costs on the U.S. power industry (and, by extension, consumers of such power) which only represents a narrow fraction of global GHG emissions when considering the many sources of GHG emissions worldwide.

EPA's proposal is based on extremely limited practical examples, and EPA is still lacking information necessary to determine appropriate parameters and considerations for the best system of emission reduction (BSER) and other proposed requirements. Based on current information, TCEQ does not agree with EPA's determination that the proposed standards (and critical supporting infrastructure) are economically reasonable.

TCEQ and RRC recommend EPA delay actual implementation of these proposals to address questionable or unproven assumptions about the performance and availability of all relevant technologies, including CCS, renewables, energy storage methods, and other generation technologies. If the rules are adopted, EPA should include exemptions for situations where the necessary infrastructure or technology is not and does not become available.

The proposed BSER standard is economically and technically unreasonable and EPA's analysis does not appropriately consider the cost of ancillary factors such as pipelines, transportation of CO_2, and storage. The full cost of the proposed standards could substantially affect competition in the power industry. Had EPA fully evaluated the costs of BSER, the proposed BSER standard based on CCS and low-GHG hydrogen would have been rejected as economically unreasonable. EPA has not provided a comprehensive assessment of the operational and technology options to meet the proposed standards. EPA has not sufficiently evaluated the proposed control technology, the availability of these options at full-scale, and cost-effectiveness. Specifically, EPA has not sufficiently evaluated hybrid plants, pipeline infrastructure, low-GHG hydrogen fuel production, and CCS to the extent necessary to make a valid determination of BSER.

By itself, the cost of CCS represents 30 to 50 percent of the total capital cost of the construction and operation of a new combined cycle natural gas-fired combustion turbine (NGCC), and the 30 percent parasitic loss resulting from CCS corresponds to a large annual operating cost. Cost overruns for this still-developing technology should also be considered and accounted for in evaluating the costs of BSER. TCEQ also notes that EPA has not investigated all possible controls for BSER. Additionally, the cost of creating the CO_2 and hydrogen pipeline infrastructure sufficient to support the widespread use of CCS and low-GHG hydrogen should also be included within the BSER determination. The total costs necessary to meet BSER must be included within the BSER determination, and TCEQ does not agree based on currently available information they are economically reasonable.

EPA's proposed rulemaking is based on assumptions or expectations about future developments and activities and proposed tax incentives associated with the IRA, without any guarantee that they will occur as projected. EPA has assumed that the IRA will incentivize companies to implement low-GHG fuel and CCS infrastructures that may or may not come to fruition, putting power companies in an untenable position if such systems are not actually implemented as EPA anticipates. It is also uncertain to what degree electric utilities will incorporate energy storage technologies as part of the grid or what dispatching strategy would be used for the stored power.

Table 9 of the preamble to the proposed rule provides details on the projected costs to implement CCS. However, as noted in Section 8.3.2.2 of the Regulatory Impacts Analysis (RIA), the projected increase in the consumer retail price of electricity ($/kW-hour) for existing combustion turbines and the third phase of the proposed standards for new combustion turbines were not calculated with the same level of detail with the Integrated Planning Model (IPM) costing tool as new natural gas-fired EGUs and for existing coal-fired EGUs, as summarized in Section 3.6.3 of the RIA. TCEQ recommends that EPA reevaluate the cost analysis for the existing combustion turbines and the third phase of the proposed standards for new combustion turbines with the same rigor as new natural gas-fired EGUs and for existing coal-fired EGUs. Further, the effect of the proposed rule on the consumer retail electricity price appears to be inconsequential according to EPA's cost estimate. TCEQ requests more details to explain this.

In the preamble to the proposed rule EPA states, "In assessing cost reasonableness for the BSER determination for this rule, EPA compares the costs of GHG control measures to control costs that EPA has previously determined to be reasonable. This includes comparison to the costs of controls at EGUs for other air pollutants, such as SO_2 and nitrogen oxides (NO_X), and costs of controls for GHGs in other industries. The costs presented in this section of the preamble are in 2019 dollars." 88 FR 33301. EPA's cost analysis for BSER is based on 2018 and 2019 dollars. However, the ratio of the U.S. GDP Implicit Price Deflator for 1Q2023 to 1Q2019 is 1.171. EPA should update the cost data to 2023 dollars, especially considering the atypically high inflation that has occurred since the Covid-19 pandemic started.

EPA should delay implementation of the proposed standards until the necessary control technologies and fuel infrastructure have been fully evaluated. If the proposed rulemaking is promulgated, then the rule should include exemptions for situations in which the pipeline infrastructure is not available to either supply low-GHG hydrogen fuel to the affected power generator or to receive and convey the exhaust streams to storage or sequestration.

CCS is not an adequately demonstrated technology and may not be reasonably cost-effective to implement. Carbon capture as a method for controlling power plant emissions has only been operated on a limited basis, and its future viability is dependent on multiple factors that have not been accounted for in EPA's analysis.

TCEQ and RRC note that there are many uncertainties about the practicality, effectiveness, and long-term performance of CCS as a method of controlling emissions of GHGs. More time will likely be needed before this technology is capable of consistently achieving and demonstrating the performance necessary to comply with the proposed standards.

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[1] Reference: U.S. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator [GDPDEF], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/GDPDEF, May 26, 2023.

EPA's BSER determination for practical application of carbon capture technology inappropriately relies on a single carbon capture unit in Texas. This is not a sufficient basis for a complete evaluation of BSER.

The BSER evaluation and proposed standards rely heavily on the actual performance of the Petra Nova facility, described by EPA as "…a 240 MW-equivalent capture facility that is the first at-scale application of carbon capture at a coal-fired power plant in the U.S. The system is located at the W.A. Parish Generating Station in Thompsons, Texas and began operation in 2017. Although the system was put into reserve shutdown (i.e., idled) in May 2020, citing the poor economics of utilizing captured CO_2 for enhanced oil recovery (EOR) at that time, there are reports of plans to restart the capture system." 88 FR 33293. EPA further notes "[d]uring its operation, the project successfully captured 92.4 percent of the CO_2 from the slip stream of flue gas processed with 99.08 percent of the captured CO_2 sequestered by EOR." Id.

The Petra Nova installation is the only known application of carbon capture on a coal fired unit built and operated in Texas, and as noted in the preamble to the proposed rule, is not currently operating. Additionally, as noted by EPA, the Petra Nova project captured 92.4 percent of the CO_2 from only a slip stream, not the entire unit exhaust stream, and there are multiple other units at the plant with emissions that are not captured. The proposed rule requires CCS with 90 percent capture of CO_2 and 88.4 percent reduction in the emission rate based on a pounds of CO_2 per gross megawatt hour (lb CO_2/MWh) [§60.5520a(a) and Table 2] for "long-term" units that anticipate operating beyond December 31, 2039. The discussion provided in the preamble is misleading because the Petra Nova project did not demonstrate meeting the 90 percent capture requirement of the proposed rule when considering the entire W.A. Parish Generating Station units' exhaust stream, as the slip stream only comprised approximately 20 percent of the exhaust stream from a single unit. TCEQ does not agree with EPA's determination that CCS is an adequately demonstrated technology at the scale, reliability, or performance needed to comply with the proposed standards. If CCS is to be required under the final rule, then EPA should identify examples demonstrating CCS is technically feasible at the scale required in the rule, not a reduced scale as was the case with the Petra Nova project.

Another factor that EPA did not consider is that the Petra Nova Carbon Capture system at the W.A. Parish Generating Station units relied upon fossil-fueled turbine compression to capture the Boiler 8 unit slip-stream that is sent for enhanced oil recovery based on the permit application and air permit issued by TCEQ when it was operational. The fossil-fuel firing that is required to implement the carbon capture will result in increased GHG emissions, which is contrary to the stated goals of the proposed rule. EPA should reevaluate its analysis to consider the effects of using compression turbines to implement the CCS at sites like Petra Nova. The Petra Nova permit (TCEQ New Source Review Permit Nos. 98664, PSDTX1268, and N138 and Title V Permit No. O-3611) issued to authorize the turbine compression and other sources triggered nonattainment new source review for NO_x as an ozone pre-cursor as well as prevention of significant deterioration (PSD), showing that the implementation of CCS can result in significant emissions of criteria pollutants.

The proposed rule would potentially require multiple permit actions for power plants in Texas. Such permit actions would put TCEQ in a position of issuing permits that require unreliable and unproven CCS technology and which, contrary to the stated goals of the proposed rule, could increase CO_2 emissions when considering the life-cycle analysis of the projects.

EPA has not provided sufficient examples and justification for the statement "[c]urrently, newly constructed and retrofit CO_2 capture systems are anticipated to have operational availability of around 90 percent, on the same order of that expected at coal-fired steam generating units."

TCEQ has only seen limited permits for the proposed capture system. It is highly uncertain whether there will be operational availability of the capture systems in the future on which the proposed rulemaking is relying. TCEQ respectfully requests that any technical evaluation and proposed outcome be re-published as a proposal to ensure comprehensive evaluation by all potentially affected parties and authorities. EPA should not complete a review and make substantive changes to the final rule without further opportunity for comments.

EPA has not considered the collateral impacts that may result from co-firing hydrogen. Further, the proposals by EPA rely on combusting low-GHG fuels but provide no clear data on actual current usage and current low-GHG hydrogen fuel system infrastructure is inadequate to supply fuel to power producers.

EPA includes details on the Entergy Orange County Advanced Power Station, a 1115 MW power plant that will replace end-of-life gas generation with new combined cycle combustion turbines capable of co-firing hydrogen with the ability to move to 100 percent hydrogen in the future. TCEQ notes that the Entergy Orange County Advanced Power Station (Permit No. 166032) will primarily fire natural gas with a capacity to co-fire up to 30 percent hydrogen as stated in the Technical Review in the public files for the project. There was no representation or review of 100 percent hydrogen firing. Due to the fuel representations, this permitting action triggered federal review for PSD, including PSD for GHGs, which also required a Title V permit. (PSDTX1598, GHGPSDTX210, O69).

Firing hydrogen fuels in turbines results in a higher flame speed that can lead to localized higher temperatures, which can increase the thermal stress on the turbine's components as well as increase thermal NO_x emissions. See Hydrogen in Combustion Turbine Electric Generating Units, Technical Support Document (TSD), EPA Office of Air and Radiation, May 23, 2023, page 4. Further, the TSD indicates that the use of steam methane reforming (SMR) to generate the hydrogen used as fuel presents challenges, as is stated as follows in the TSD: "From an overall GHG emissions perspective, the use of hydrogen from SMR would increase emissions compared to using the natural gas directly in a combustion turbine to produce electricity. This is because the thermal efficiency of SMR of natural gas is generally 80 percent or less, therefore, less overall energy is in the produced hydrogen than in the natural gas required to produce the hydrogen." Id. at 14.

While electrolysis can be used to generate hydrogen, the TSD notes that the energy intensity of electrolysis is high, so potential GHG emission reductions from the use of hydrogen versus fossil fuels in a combustion turbine are largely dependent on the form of energy used to power the hydrogen production process. If that form of energy is renewable (e.g., solar) or nuclear, then the GHG reductions associated with using hydrogen as a fuel could be significant." Id. at 19-20. There is no guarantee that renewable energy will always be used to produce hydrogen through electrolysis, so the overall GHG emission benefits associated with this method of hydrogen production are uncertain.

EPA has not provided an estimate of the current amount of electricity generated by combusting "low-GHG hydrogen." It is not clear from the historical data what percentage of current U.S. electric generation is from low-GHG hydrogen fuel, nor is there any data on the reliability of hydrogen fuel. Such uncertainties could place electric grids in precarious situations and affect the reliability of electric generation.

TCEQ respectfully requests that any technical evaluation of hydrogen firing include the resulting collateral NO_x emissions, and that a full life-cycle analysis be prepared for public review. A revised rule proposal including this information should be re-published to ensure comprehensive evaluation by all potentially affected parties and authorities. EPA should not complete a review and make substantive changes to the final rule without further opportunity for comments.

EPA's proposed requirement that hydrogen fuel must meet a low-GHG fuel specification does not affect GHG emissions from power plants and only mitigates GHG emissions on sources outside the power plant sector subject to the proposed rule. As such, the low GHG-hydrogen requirement cannot be considered part of BSER for the power plant sector and is in violation of the U.S. Supreme Court's decision overturning the Clean Power Plan.

Fuel specification requirements can, in some cases, result in reduced emissions for a fossil fuel-fired unit and might be considered BSER. For example, a low-sulfur coal fuel requirement would reduce sulfur dioxide emissions from the unit at the site. However, this is not the case with EPA's proposed requirement that hydrogen fuel must meet a low-GHG specification. While burning hydrogen fuel in place of fossil fuel will reduce CO_2 emissions, the generation method of the hydrogen fuel has no impact on the amount of CO_2 emissions from the power plant burning that hydrogen. EPA cannot claim that low-GHG hydrogen is within the scope of BSER for a power plant because the source of the hydrogen will not change the degree of CO_2 emissions reduction achieved at the power plant itself. EPA is exceeding its authority by attempting to indirectly reduce GHG emissions from the hydrogen-generating industry by imposing a low-GHG requirement on the hydrogen fuel required under this proposed rule for power plants.

Additionally, EPA's proposed low-GHG hydrogen requirement is contrary to the U.S. Supreme Court decision that overturned the Clean Power Plan, *West Virginia v. EPA*, 142 S.Ct. 2587 (2022). Congress did not intend for the Act to drive such a significant change in the development of domestic energy supply that will have global scale impacts, nor did it grant unheralded power to EPA to make such a change. "Under our precedents, this is a major questions case. In arguing that [FCAA] §111(d) empowers it to substantially restructure the American energy market, EPA 'claim[ed] to discover in a long-extant statute an unheralded power' representing a 'transformative expansion in [its] regulatory authority.'" *West Virginia v. EPA*, 142 S.Ct. at 2610 (citing Utility Air Regulatory Group v. EPA, 573 U.S. 302, 324 (2014))). EPA's proposed low-GHG hydrogen requirement is the same form of expansion of authority as cited in the Supreme Court's major questions case. EPA is attempting to assume an authority that Congress did not provide by imposing a requirement on the electric utility sector in order to achieve emission reductions from an industry sector not even subject to the proposed regulatory action.

The proposed rules would have major implications for New Source Review (NSR) permitting authorities and NSR permit holders, particularly major source Prevention of Significant Deterioration (PSD) or nonattainment NSR (NNSR) authorizations in Texas.

TCEQ has issued over 400 permits for coal-fired, liquid-fired, or natural gas-fired steam EGUs and turbines. The proposed rule would dramatically affect the regulated community and potentially require a majority of affected permit holders to seek permit amendments to comply with the proposed rule. In Texas, numerous NSR air permits will need to be amended or newly issued to authorize the required CCS systems or hydrogen fuel firing required by the proposed rule. These permit actions will include an analysis of best available control technology (BACT), predicted air dispersion impacts/health effects demonstrations, proposed monitoring, proposed recordkeeping, drafting of the permit conditions and maximum emission rates table, two public notice periods (when the application is declared administratively complete and later when the draft permit is issued), permit negotiation, and other associated permit analyses and evaluations. Additionally, review and issuance of air permits triggering federal major NSR will likely take longer than the deadlines allowed under these proposed GHG rules. Such major PSD and NNSR projects typically take a year to 18 months to review, depending on the complexity of the projects and degree of public interest. The technical review for major NSR projects includes the items listed above as well as federal BACT or lowest achievable emission rate (LAER) analyses, as appropriate for each pollutant, major project impacts modeling, and an additional impacts analysis. These applications require a technical review and concurrence by TCEQ of each item in the permit application.

Due to the fundamental problems related to the technologies EPA anticipates will be developed to meet the proposed standards, it is highly likely that EGU owners and operators will have to delay engineering design, pre-construction permit applications, NSR and Title V major source permit applications, construction, testing, and final compliance until closer to the proposed rule deadlines. This is likely to cause a bottleneck at each of these stages and result in high demand for regulatory agency permitting resources that are not currently available.

The proposed changes to the NSPS requirements will cause inconsistency with existing TCEQ tools and methods to review and issue permits. TCEQ currently does not have authority from the Texas Legislature for a minor source permitting program for GHGs. Rules and guidance would have to be developed and issued by TCEQ and legislative authority from the Texas Legislature may be needed. For NSR authorizations, boilerplate special condition language and guidance documents will require revisions to prevent regulatory discrepancies and overlap. Compliance assurance monitoring (CAM) and Periodic Monitoring (PM) for the sources will also have to be established. Facilities with standardized authorizations such as the Texas EGU standard permit may be subject to the proposed rules and those authorizations would need to be reviewed and modified by TCEQ to ensure compliance with the proposed rules. States, like Texas, with many EGUs will be disproportionately impacted by the rule and will require more time and resources to implement. If the proposed standards are adopted, EPA should consider these impacts and adjust grant funding or other resources to facilitate implementation.

Texas would be particularly impacted by the proposed standards due to several reasons. The Texas grid primarily operates as an independent system. Further, the high number of EGUs in the state, the great level of diversity in physical locations and availability of natural and supporting resources (water, pipelines), the increasing state population, and Texas' high demands on the grid due to weather conditions (extreme cold and heat) create additional complications and considerations. If the proposed standards are adopted, EPA should consider these impacts and the need for additional resources to facilitate implementation.

The proposed rules would have considerable implications for Title V permitting authorities and permit holders. TCEQ opposes the proposed approach to require reopening of Title V permits and the proposed 18-month deadline. EPA should provide additional time or flexibility for permitting authorities and Title V permit holders to make the necessary permit revisions.

Title V regulations require each permit to include emission limitations and standards, including operational requirements and limitations, that assure compliance with all applicable requirements. Requirements resulting from these rules that are imposed on EGUs or other potentially affected entities that have Title V operating permits are applicable requirements under the Title V regulations and would need to be incorporated into the source’s Title V permit in accordance with the schedule established in the Title V regulations. The process of obtaining or revising a Title V permit can take up to one year from receipt of an initial complete application. However, the receipt of significant public or EPA comments can extend that timeframe. Regarding the impact of the proposed rulemaking and proposed rule implementation on Title V permitting, TCEQ does not agree with the proposed fast-track changes. They should be delayed until EPA provides TCEQ with funding, resources, and time necessary to develop the tools and processes required for the implementation of these rules and the associated Title V permit revisions.

TCEQ is possibly the only regulatory agency in the U.S. that has developed the Decision Support System (DSS) tools and processes to generate applicable requirements in a Title V permit issued under 40 CFR Part 70 and subject to various state and federal rules. Many other regulatory agencies rely on TCEQ's DSS in the issuance of their Title V permits. The DSS consists of Requirement Reference Tables (RRT), unit attribute forms, and regulatory flowcharts that assist in making applicability determinations and which also include applicable standards and monitoring, recordkeeping, reporting, and testing (MRRT) requirements for each affected unit. Development and maintenance of the DSS is a complex effort and TCEQ has dedicated significant time and resources towards supporting the system and its continued development. TCEQ's DSS team has a heavy workload that will be further strained by the need to address these and other regulations recently proposed by EPA. In addition to the need to update the DSS, TCEQ will need to determine if any General Operating Permits (GOPs) may be affected by the proposed rules, and if so, affected GOPs will need to be amended or developed. If the proposed rules are adopted, EPA must consider the additional Title V infrastructure development and support that permitting authorities will have to undertake and provide states with a corresponding increase in funding and additional resources. EPA should also take into account the time needed for these support systems to be developed or updated and provide corresponding flexibility with permitting deadlines.

TCEQ opposes the proposed requirement for a "permit reopening" that "shall be completed no later than 18 months after promulgation of the applicable requirement." As proposed, this requirement to complete the permit reopening as of a specific deadline would create a large number of permit actions that would need to be completed on the same schedule, which could create a bottleneck or resource issue for permitting authorities.

In the past, TCEQ has not used the permit "reopening" process when new applicable requirements are promulgated. Rather, TCEQ has relied on permit holders submitting appropriate revisions to existing permits and regulated entities knowing when to submit applications for new Title V permits. In addition, if revisions to TCEQ's Federal Operating Permit rules (30 Texas Administrative Code (TAC), Chapter 122) are needed to address the "reopening" requirement or any other change caused by the proposed changes to the NSPS requirements, TCEQ will need to complete the rulemaking process and submit a program revision to EPA for approval before any implementation may begin. These Title V rule and program revisions would likely take at least a year for TCEQ to complete, and additional time to be reviewed and approved by EPA, consuming most or all of the 18-month period EPA has proposed to allow for sources needing permit actions.

TCEQ also proposes that the second portion of the above statement, that permit reopening "shall be completed" no later than 18 months after promulgation, be replaced by "if the permit has a remaining life of three years or more, a permit holder shall submit an initial application or a permit revision application, as applicable, to incorporate the newly applicable requirement no later than 12 months after promulgation of the applicable requirement." This recommended change to focus on the application submittal (rather than the permit completion date) would be more reasonable considering that regulated entities will not have direct control over the length of time required to process the permit, especially in states with a large number of EGUs needing immediate permit revisions and/or states where changes to the overall Title V program may be needed to facilitate the permit reopenings or revisions.

TCEQ encourages EPA to provide maximum flexibility regarding the methods or techniques EGUs may use to meet any revised standards and associated deadlines.

Since the stated goal of the rule is to reduce GHG emissions, both CCS and co-firing of low-GHG hydrogen should be allowed as options to meet the rule standards. However, as discussed below, many questions remain about BSER for EGU facilities. TCEQ recommends that EPA provide as much flexibility as possible in how the standards are met, instead of mandating narrow or prescriptive methods of compliance. EPA should provide maximum flexibility regarding the techniques, methods, scale, and time limits for implementation, especially considering the lack of current (and possibly future) infrastructure for low-GHG hydrogen fuel, and available CO_2 capture, transport, and storage techniques. EPA should allow owners or operators of EGUs the flexibility to use emerging or new technologies if they are capable of meeting the same goals or standards. EPA should also consider that significant time will be needed for permitting of new equipment and modifications.

EPA proposes hydrogen co-firing and CCS as BSER for NGCCs as well as coal-fired EGUs. But the discussion of differences between flue gas from the two types of sources are significant enough that the determination of these controls as BSER for the NGCC is even less supported. As EPA indicates, the CO_2 concentration for NGCC is one-third of that for coal-fired EGUs; the volumetric flow rate on a per MW basis is larger for NGCC compared to coal-fired EGUs; and the O2 concentration is three times higher for NGCC compared to coal-fired EGUs. These characteristics reduce the efficiency of CO_2 capture and may require a larger CO_2 absorber for NGCC than would be needed for coal-fired EGUs. EPA includes discussion of exhaust gas recirculation (EGR)/flue gas recirculation (FGR) to address these issues, which also indicates that BSER for NGCC will be different for control of CO_2 than the BSER for coal-fired EGUs.

B. Comments on Proposed FCAA §111(d) State Plan Rule, 40 CFR Part 60, Subpart UUUUb and Proposed FCAA §111(b) NSPS, 40 CFR Part 60, Subpart TTTTa

A minimum of 36 months is needed for states to develop FCAA §111(d) state plans for steam generating units. If EPA is going to stage plan submittals for different subcategories, a minimum of 24 months between submittals is needed. EPA should also include a provision that allows for states to petition for additional time.

EPA has not accounted for the time necessary for administrative processes associated with state rulemaking and administrative aspects necessary for states to submit a state plan. TCEQ estimates that approximately nine (9) months would be required for meeting agency administrative procedures, state and federal notice and public hearing requirements, and other administrative requirements for the state plan and associated rulemaking. Of the 24 months that EPA proposes to allow for state plan submissions, Texas would only have approximately 15 months to conduct the required meaningful engagement; coordinate with other Texas state agencies when developing the state plan, such as the Railroad Commission of Texas, Public Utility Commission of Texas, and the Electric Reliability Council of Texas (ERCOT); engage with affected regulated entities; determine unit categories and baselines for each affected unit; evaluate potential for remaining useful life; determine standards of performance; work with affected regulated entities to set increments of progress; and draft the state plan and the associated rules. Furthermore, in some cases, other Texas state agencies may need to perform extensive technical analysis and modeling, as may be the case with ERCOT, to assess the potential impacts to grid reliability. TCEQ cannot absorb the additional workload to develop a state plan of this magnitude on such a short schedule without pulling away staff that are dedicated to other mandated programs. At a minimum, states should have 36 months for the development and submittal of the FCAA, §111(d) state plan.

EPA is taking comment on a 24-month submittal deadline for steam generating units and a 36-month submittal deadline for combustion turbine subcategories. If EPA is going to stage plan submittals in such a manner, a minimum of 24 months between deadlines is needed to reduce overlap in plan development activities. As noted above, TCEQ has limited resources and staging plan submittals will help manage the work. Furthermore, given the extremely long compliance time period for the hydrogen co-firing stationary combustion turbine subcategory, i.e., January 1, 2038 and the uncertainty associated with many aspects of the subcategory and unit operations that far into the future, additional time will be needed for plan development. Therefore, TCEQ suggests that if EPA is going to stage plan submittals in such a manner, EPA should provide a minimum of 36 months for state plans for the steam generating unit subcategory and 60 months for the combustion turbine subcategory.

EPA should also include provisions to provide additional time to states upon request. State-specific situations may require time to develop and submit a state plan. A state with a large number of applicable sources may require additional time for technical evaluation and stakeholder engagement. As EPA has noted in the past, FCAA, §111(d) only requires that the process for state plans should be similar to the state implementation plan (SIP) process under FCAA, §110. Therefore, EPA is not bound to the deadlines set in FCAA, §110 for SIP submittals.

Section 111(d) of the FCAA specifically requires EPA to allow states to consider remaining useful life and *other factors* when assigning standards of performance. EPA should specifically provide for states to consider other factors such as grid reliability and attainment status for the NAAQS.

As TCEQ has previously commented during EPA's pre-rule request for comments on controlling GHG emissions from EGUs, electrical grid reliability is a critical *other factor* that needs to be considered when setting standards of performance for EGUs. EPA should explicitly clarify in rule that states may consider reliability when developing a FCAA, §111(d) state plan for existing EGUs. EPA's request for comment regarding administrative compliance orders for addressing grid reliability concerns would only address short-term, likely unexpected, reliability issues, not reliability issues that could result from utility decisions regarding compliance with a state plan itself, i.e., the impact of unit shutdowns on resource adequacy.

Additionally, hydrogen co-firing can increase emissions of NO_x and an increase in NO_x emissions at EGUs in nonattainment areas could impact the state's ability to comply with the NAAQS. The NAAQS and potential impacts to the SIP are relevant "other factors" that states should be allowed to consider when setting standards of performance for existing EGUs in a FCAA, §111(d) state plan. Given the degree that the proposed rule is relying on hydrogen co-firing, the states need flexibility to set alternate standards for EGUs in nonattainment areas to avoid impacts that could interfere with federally enforceable SIP requirements and the ability of the area to attain the NAAQS.

The proposed increments of progress requirements for certain existing unit subcategories are arbitrary, unnecessary, and place an unreasonable burden on states. Increments of progress should only be required in situations where the state plan establishes a compliance time longer than recommended by EPA in the EG.

The proposed requirement for state plans to include increments of progress severely complicates state plan development. The requirement appears to be based solely on the compliance timeline being longer than EPA's arbitrary 16-month time period proposed with the revisions to the implementation regulations in 40 CFR Part 60, Subpart Ba. Calendar date specific deadlines for awarding contracts, permitting, start of construction, end of construction, and similar activities will vary substantially based on numerous factors that even companies with affected units may not know at the time of state plan development. The likely outcome is that each affected unit that would be subject to the increments of progress requirements would have distinct separate dates for each increment. The requirement is particularly problematic for combustion turbines in the hydrogen co-fired subcategory, which has a proposed final compliance date, of January 1, 2038 for the required 88.4% reduction, more than a decade after EPA's projected state plan submittal deadline of June 2026.

Increments of progress should only be required when a state plan establishes a compliance timeframe beyond what EPA has recommended in the EG. There is no practical value in the state or EPA attempting to micromanage the construction and planning activities for sources that will comply with the EG standards by the expected compliance date. Furthermore, the requirement for the increment of progress places a severe burden on the state when applied to many sources. EPA's proposed requirement will likely result in states receiving numerous requests to revise the enforceable compliance dates for increments of progress as companies proceed with implementation. Because the legally enforceable dates for the increments of progress must be included in the state plan, any revision to such dates will require proposal; public notice and comment; adoption; and submittal of the revised plan. As noted elsewhere in TCEQ's comments, the administrative process alone for submitting a state plan is approximately nine (9) months and the same is true for any revision to a plan.

Additionally, the implementing regulations in 40 CFR Part 60, Subparts B and Ba, specify that state plans must only include the specific increments of progress listed *where practicable*. However, proposed 40 CFR §60.5740b(a)(4) overrides this flexibility. Some of the increments may not be possible to set specific calendar dates because the activities are too far in the future. This flexibility has been included in the FCAA, §111(d) implementation regulations since 1975 and EPA has not provided any justification for overriding this language with the current proposal. EPA should retain this flexibility and allow states to exclude increments of progress that are not practicable for a specific situation.

Finally, regarding proposed 40 CFR §60.5740b(a)(4)(v), permitting for pipeline construction is outside TCEQ's jurisdiction. Pipeline permitting in Texas is under the jurisdiction of the Railroad Commission of Texas. TCEQ has neither the authority nor the expertise to set deadlines for pipeline permitting activities and evaluate the supporting evidence that EPA is proposing to require companies provide to demonstrate they have commenced permitting actions.

The proposed methodology for establishing the unit-specific baseline for emission performance should be clarified. States will need additional flexibility in setting baseline periods to account for situations that EPA has not considered.

The methodology for establishing a unit-specific baseline in 40 CFR §60.5775b(d) requires the use of the most representative continuous 8-quarter period from 40 CFR Part 75 reporting within the five years immediately prior to the date of the publication of the final rule. EPA should clarify whether the five-year period is on a calendar year basis or if the five-year period would end on the most recent quarter reported to EPA Clean Air Markets data system under 40 CFR Part 75 prior the final rule publication. The preamble language appears to indicate that the five-year period is on a calendar year basis by indicating that a state would evaluate data from 2018 through 2022 when establishing a baseline in the year 2023 (88 FR 33375). If this is the case, the rule should specifically indicate that the five-year period is on a calendar year basis.

EPA should also include a provision that allows states to select a different time period for setting the baseline in situations where the five years prior to EPA finalizing the rule might not be representative. For example, TCEQ has an enforceable agreement with Xcel Energy for all three coal-fired units at the Harrington Station facility to cease burning coal and convert to natural gas fuel by no later than January 1, 2025. As EPA has proposed the rule, the units at Harrington Station would be defined as a natural gas-fired steam generating units, i.e., the three calendar years prior to January 1, 2030, would be as natural gas-fired units. However, EPA's proposed window for setting the eight consecutive quarter baseline period would be the five years prior to EPA's final rule, which will overlap with the period that Harrington Station would be burning coal. Therefore, the units at Harrington Station would not have eight consecutive quarters as natural gas-fired steam generating units in the five-year period proposed by EPA. States will need flexibility in selecting the baseline period to address such situations.

EPA's proposed website publication requirements for states and owners or operators with affected existing units is unnecessary and burdensome, and EPA has not identified a legal authority for imposing such requirements. EPA would more effectively achieve their goal of providing the public easy access to the information by developing an EPA-maintained centralized website.

EPA has proposed to require companies subject to 40 CFR Subpart UUUUb to post documentation on a publicly accessible website and require states to have a publicly accessible website that provides links to all the individual company websites for those facilities included in the state plan. EPA has not identified the specific authority granted under the FCAA §111(d) or any other authority that allows EPA to impose on companies or states requirements to develop and maintain such websites. Additionally, maintaining a state-run webpage with up-to-date links with all the individual company websites creates an unnecessary burden on the states and is an inefficient approach to achieving EPA's goal of providing interested stakeholders access to the information. The best way to satisfy EPA's objective and minimizing the redundancy and burden is for EPA to maintain its own website with all the requisite records from affected EGUs, rather than burden the states and affected owners and operators with maintaining such websites. As EPA acknowledges, this information would already be submitted to EPA under the proposed rule. Furthermore, EPA's proposed approach would require stakeholders to visit individual state websites to find individual company sites, and then visit the private company websites with the unit-specific information to access the records. A stakeholder seeking information from all affected units would have to visit hundreds of different state and company websites. An EPA centralized website would have the added benefit of greatly reducing the burden on interested stakeholders to find such information because the records would be available on a single website.

EPA does not have the authority to prohibit states from submitting revisions to a state plan, even temporarily, and imposing such a prohibition could have adverse unforeseeable consequences.

EPA is taking comment on imposing a cutoff date for submitting revisions to a state plan, effectively imposing a temporary prohibition on a state revising a previously submitted state plan (88 FR 33403). Neither the states nor EPA can anticipate all possible scenarios and outcomes that might arise over the course of the compliance timeline after an initial state plan is submitted. Imposing such prohibition on revising a state plan, even temporarily, exposes the state and utilities to unnecessary risks should events arise that necessitate revising the state plan to address an emerging situation. Furthermore, there is no provision in FCAA §110 or §111 that allows EPA to prohibit a state from submitting a revision to a previously submitted state plan or SIP. EPA has no legal basis for establishing such a moratorium, even temporarily.

TCEQ does not support earlier compliance dates than proposed by EPA for newly constructed or reconstructed facilities to reflect application of the more stringent controls in BSER.

As stated in TCEQ's more general comments about rule deadlines, TCEQ is opposed to earlier compliance dates for the more stringent controls. If the proposed rules are adopted, the rule implementation should be delayed until the low-GHG hydrogen fuel system and CCS infrastructure are sufficiently robust to ensure that power generators have adequate access to these critical networks which are necessary to comply with the rule. EPA's expectations for the development of these infrastructure systems are based on projections resulting from tax incentives that may not come to fruition and could put power generators in a potential non-compliance situation.

TCEQ supports EPA's proposal to allow states to implement optional emissions trading programs as a method of complying with the proposed standards.

TCEQ encourages EPA to allow states to implement emissions trading programs as a flexibility tool for EGUs to demonstrate compliance with the EG. TCEQ agrees that development of trading programs to comply with the proposed EG would have multiple challenges given the unique characteristics of existing EGU fleets. TCEQ also agrees that emissions trading programs should not be mandatory. Additionally, EPA should not require or establish prescriptive trading programs in the final rule but should allow states broad authority to design a trading program that meets the requirements of proposed 40 CFR §60.5775b(g). The procedures necessary for a trading program will be included in a state plan and EPA will have the opportunity to review any proposed trading program, including which subcategories of EGUs to include, if programs should be rate-based or mass-based, and appropriate methodologies for emissions verification.

TCEQ recognizes interstate trading may provide additional flexibility for some states; however, the proposed 24-month implementation schedule is insufficient to allow states to negotiate and coordinate administration of program requirements. In addition, the unique characteristics of each states' geography and existing fleets of EGUs may create additional challenges for implementation of nationwide interstate trading.

TCEQ recommends that EPA allow states broad authority to design trading programs, if determined to be necessary, to meet the compliance goals and deadlines set in the EG. EPA should not require or establish prescriptive trading programs, including interstate trading. States should have the option to voluntarily implement interstate or intrastate trading programs.

TCEQ supports maintaining the current exclusion for certain specified gaseous fuels (such as landfill gas, coal-derived gas, etc.) in the definition of natural gas. Additionally, TCEQ is opposed to the proposed changes removing the subcategory of multi-fuel-fired combustion turbines.

TCEQ supports maintaining the current exclusion in the definition of "natural gas" for the specified types of gases. Landfill gas, coal-derived gas, or other gases likely have higher particulate content, the presence of other contaminants, or higher sulfur content than pipeline quality natural gas. Typical natural gas sulfur content and particulate matter content are used in permit representations for natural gas combustion units. Changes in the definition would trigger the need for permit amendments if those typical or representative sulfur and particulate matter concentrations were no longer valid. This may result in emissions increases of criteria pollutants subject to NAAQS.

Any proposed definition of natural gas should be consistent with other widely used definitions in 40 CFR Parts 72 and 75. The proposed definition includes reference to a mix of hydrocarbons, a minimum methane content or gross calorific value, minimum heat content, and gaseous state. The sulfur content restrictions within 40 CFR Parts 72 and 75 must also be included.

EPA is also proposing to remove the multi-fuel subcategory for turbines. TCEQ supports the appropriate use of landfill gas, coal-derived gas, or other gases as fuels, which allows useful energy to be recovered from these waste gases and reduces consumption of other fuels. TCEQ is opposed to changes that would limit the ability for EGUs to utilize these other sources of energy.

TCEQ does not support hybrid power plants as BSER for base load combustion turbines.

In the preamble to the proposed rule EPA discusses a hybrid plant consisting of a concentrated solar thermal energy source producing low-quality steam combined with a coal-fired steam boiler EGU or with the heat recovery steam generator for a natural gas-fired combined cycle combustion turbine. 88 FR 33419. The discussion also references the fact that this low-quality steam from solar thermal energy will need additional heating in order to help drive a power generator at a sufficient level of efficiency. That additional heating will come from the combustion of fossil fuel, resulting in additional collateral emissions being generated, including GHGs. As EPA concludes in the preamble, the discussion does not support hybrid power plants as BSER for combustion turbines.

TCEQ respectfully requests that any technical evaluation and proposed outcome be re-published as a proposal to ensure comprehensive evaluation by all potentially affected parties and authorities. EPA should not complete a review and make substantive changes to the final rule without further opportunity for comments.

TCEQ does not support the use of highly efficient simple cycle turbines to qualify as BSER for low load combustion turbines.

TCEQ agrees that low load turbines should not be subject to BSER of low-GHG hydrogen fuel or CCS for control of CO_2 emissions. The use of natural gas fuel for these low load units is reasonable for areas with access to natural gas and is technically feasible. Requiring highly efficient designs for these low load turbines may be unreasonable considering the predicted highly variable operations of these types of units.

TCEQ supports flexibility to allow either manufacturers to certify or have individual units perform initial performance testing for low load combustion turbines to verify the GHG emissions rate. EPA should clarify which reference method(s) are to be used to demonstrate compliance.

TCEQ supports allowing manufacturers to conduct performance testing to certify the design GHG emission rate for standard units. To provide flexibility and ensure accurate test results, the rule should allow either the manufacturer or the owner to conduct initial emissions testing provided that the manufacturer certifies the test, or the owner or operator follows approved EPA test methods, if they conduct the stack testing themselves.

The federal reference method used for the initial emissions test to demonstrate compliance should be specified. EPA Reference Methods 3 and 3B for CO_2 state a sensitivity of 2,000 ppmv in Section 1.1. It is unclear if these methods are appropriate to demonstrate compliance with the proposed requirements. EPA should specify which reference method(s) should be used for the lower emitting fuels, as Method 3 is very commonly used for CO_2 determination.

TCEQ does not agree with the assumption that natural gas-fired stationary combustion turbine EGUs running at more stable operation and, thus, more efficiently (i.e., at higher duty cycles and for longer periods of operation per start) will necessarily result in a decrease of GHG emissions.

From an economics perspective, operating turbines at full loads for extended periods will increase the efficiency and result in more economical fuel usage. However, the converse is true for the GHG emissions, as a higher proportion of natural gas will be converted to CO_2 due to more complete combustion that results from the higher efficiency turbine. It does seem plausible that natural gas-fired stationary combustion turbine EGUs may run at more stable operation in the future. Reasons for this may include the closure of coal-fired steam generating units, the decreasing cost of natural gas, and units built in support of renewable generation, such as robust peaking units that can easily be started and stopped. Electricity from renewable sources can be available and not available in quick succession and non-renewable peaking units can be used to rapidly provide electricity when renewable-sourced electricity is not available. This type of flexible generation will be needed for the foreseeable future until energy storage technologies are more readily available and proven.

Turbine operations, specifically related to load and durations, are highly dependent on seasonal market demands. The proposed rule places an undue burden on power producers by requiring infrastructure to be built (low-hydrogen fuels or CCS systems) for these less-used units to allow affected facilities to comply with the rule. The required investment in infrastructure may result in possible reliability and non-compliance issues due to the lower priority of these less-used units if they are unable to run at stable rates throughout the year. For all of these reasons, for purposes of establishing standards under FCAA §111, EPA should not assume that generation from gas-fired combustion turbines will inherently become more stable or that associated GHG emissions from those units will decline.

While hydrogen rich fuels contain less carbon and therefore will reduce CO_2 emissions when compared to carbon-rich natural gas and coal fuels, hydrogen rich fuels will also increase the combustion flame temperature, resulting in increased thermal NO_x emissions.

In addition to the increased thermal NO_x emissions resulting from firing hydrogen rich fuels, the emissions could also increase as a result of the additional fuel and energy needed to compress the exhaust gases to direct them to CCS, or to generate the hydrogen fuel, including any parasitic fuel load. EPA has indicated several approaches for generating hydrogen-rich fuel including steam reforming with CCS and hydrolysis, all of which are power-consuming processes that will increase GHG emissions when considering a full life-cycle analysis.

The parasitic load imposed by the application of CCS to recover and store carbon emissions causes a reduction of available power to the grid. EPA and the U.S. Department of Energy have indicated within the TSD for Steam EGUs that implementation of CCS at existing coal EGUs has a 24 to 34 percent capacity penalty; that is, approximately 30 percent of the power that was previously available for generation and distribution would now be required for implementation of CCS. For new combustion turbines, EPA estimates in its TSD for Combustion Turbines that the derate from implementing CCS is 11 percent. Thus, to generate the same amount of power as without CCS, more fuel burning would be needed, which would generate additional emissions of CO_2 and other pollutants. This increased production of CO_2 (and other) emissions is in direct conflict with the stated goals of the rule. EPA should re-evaluate the increased emissions that would result from the parasitic load at power facilities in which CCS is implemented.

CO_2 concentration for NGCC is one-third of that for coal-fired EGUs; the volumetric flow rate on a per MW basis is larger for NGCC compared to coal-fired EGUs; and the O2 concentration is three times higher for NGCC compared to coal-fired EGUs. These characteristics reduce the efficiency of CO_2 for coal-fired EGUs.

TCEQ does not support a requirement that the enforceable commitment must be in the form of an emission limit of zero-lb CO_2/MWh.

TCEQ does not support a specific requirement that the permit or other enforceable commitment must be in the form of an emission limit of 0 lb CO_2/MWh, as this seems needlessly prescriptive. TCEQ encourages EPA to recognize delegated or SIP-approved states' enforceable permit conditions, certifications, and voiding of authorizations, as practically enforceable. As demonstrated in prior submittals relating to TCEQ's minor and major source permitting programs, TCEQ has sufficient legal authority to enforce the conditions and emission limitations contained in its permits, including schedules and deadlines for the shutdown of facilities or the transition to a different type of fuel.

EPA requested comment on whether continuous CO_2 and flow measurements should become the sole means of determining compliance for this rule. TCEQ agrees with EPA's observation that such a switch would increase costs for those EGU owners or operators who are currently relying on other approaches for compliance and does not support that continuous CO_2 monitoring be established as the only means of determining compliance.

Sources affected by the proposed rules typically must perform continuous monitoring for NO_x and CO, and possibly other pollutants. Flow meters for fuel are also common for these sources. Assuming channel space is available at existing continuous emission monitoring systems (CEMS) for the facilities, adding monitoring for CO_2 will incur some costs to implement.

TCEQ also notes that relative accuracy test audit (RATA) procedures to be used in order to validate the required CO_2 CEMS are insufficiently specified. The proposed rule does not specify the reference method used to perform the RATAs for the required CO_2 CEMS, merely calling for "an appropriate reference method." EPA Reference Methods 3 and 3B state a sensitivity of 2,000 ppmv in Section 1.1. TCEQ requests that EPA review and confirm whether these methods are sufficiently accurate and precise to be used to perform RATAs for CO_2 CEMS. If not, EPA should specify what reference methods should be used, as Method 3 is very commonly used for CO_2 determination.

The requirement for CO_2 RATAs will be an added financial burden on the regulated community. In addition, the proposed rule does not allow the use of the 0.84 default pitot tube coefficient in Method 2; this will greatly limit the number of stack testing contractors available to serve this need. Many stack testing companies do not have access to a wind tunnel for calibration of the pitot tubes, and some are very small businesses with limited capital. Currently, many companies use the 0.84 default coefficient exclusively.

It is currently unclear how many facilities will be required to perform RATAs for CO_2 CEMS by this rule, and so the additional burden on TCEQ and other regulatory agencies for observation and review of stack tests and RATAs required by this rule cannot currently be determined, but may become significant if there are a large number of facilities required to perform CO_2 RATAs.

Therefore, TCEQ encourages EPA to provide maximum flexibility in the monitoring and calculation methods that EGUs may employ to demonstrate compliance and not require mandatory CO_2 CEMS (and therefore RATAs) for all facilities.