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This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 21, 1993.

TRD-9323299 Marjorie A. Bronk, R.N., M.S.H.P.
Executive Director
Board of Vocational Nurse Examiners

Effective date: June 11, 1993

Proposal publication date: April 20, 1993

For further information, please call: (512) 835-2071

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Chapter 237. Continuing Education

Continuing Education

• 22 TAC §237.19

The Board of Vocational Nurse Examiners adopts an amendment to §237.19, without changes to the proposed text as published in the April 20, 1993, issue of the *Texas Register* (18 TexReg 2517).

The rule is adopted to make licensing and continuing education rules consistent.

No comments were received relative to the amendment of this rule.

The amendment is adopted under Texas Civil Statutes, Article 4528c, §5(g), which provide the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purposes of the law.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 21, 1993.

TRD-9323298 Marjorie A. Bronk, R.N., M.S.H.P.
Executive Director
Board of Vocational Nurse Examiners

Effective date: June 11, 1993

Proposal publication date: April 20, 1993

For further information, please call: (512) 835-2071

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Chapter 239. Contested Case Procedure

Hearings Process

• 22 TAC §239.33

The Board of vocational Nurse Examiners adopts new §239.33, relative to release of information, without changes to the proposed text as published in the April 20, 1993, issue of the *Texas Register* (18 TexReg 2518).

This rule was adopted to delineate what investigations division information can be released.

No comments were received relative to the adoption of this rule.

The rule is adopted under Texas Civil Statutes, Article 4528c, §5(g), which provide the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purposes of the law.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 21, 1993.

TRD-9323297 Marjorie A Bronk, R.N., M.S.H.P.
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Board of Vocational Nurse Examiners

Effective date: June 11, 1993

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For further information, please call: (512) 835-2071

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TITLE 31. NATURAL RESOURCES AND CONSERVATION

Part III. Texas Air Control Board

Chapter 117. Control of Air Pollution From Nitrogen Compounds

• 31 TAC §§117.1-117.4

The Texas Air Control Board (TACB) adopts the repeal of §§117.1-117.4, and adopts new §§117.10, 117.101, 117.103, 117.105, 117.107, 117.109, 117. 111, 117.113, 117.115, 117.117, 117.119, and 117.121, 117.201, 117.203, 117. 205, 117.207-117.209, 117.211, 117.213, 117.215, 117.217, 117.219, 117.221, 117.301, 117.305, 117.309, 117.311, 117.313, 117.319, 117.321, 117.401, 117. 405, 117.409, 117.411, 117.413, 117.419, 117.421, 117,451, 117.455, 117.458, 117.510, 117.520, 117.530, 117.540, 117.550, 117.560, 117.570, and 117.601, concerning Control of Air Pollution From Nitrogen Compounds. Sections 117.010, 117.101, 117.103, 117.105, 117.107, 117.109, 117.111, 117.113, 117.115, 117. 117, 117.119, 117.121, 117.201, 117.203, 117.205, 117.207-117.209, 117.211, 117.213, 117.215, 117.217, 117.219, 117.221, 117.305, 117.309, 117.313, 117. 319, 117.321, 117.405, 117.409, 117.413, 117.419, 117.421, 117.451, 117.510, 117.520, 117.530, 117.540, 117.560, 117.570 and 117.601 are adopted with changes to the proposed text as published in the November 20, 1992, issue of the *Texas Register* (17 TexReg 8136). Sections 117.301, 117.311, 117.401, 117.411, 117.455, 117.458, and 117.550 are adopted without changes and will not be republished. Sections 117.206 and 117.220 are being withdrawn.

The adopted revisions to Chapter 117 were developed in response to requirements of the 1990 Federal Clean Air Act Amendments and the U.S. Environmental Protection Agency (EPA) to implement Reasonably Available Control Technology (RACT) controls for certain stationary sources of nitrogen oxides in the Houston/Galveston area and Beaumont/Port Arthur area ozone nonattainment counties (Brazoria, Chambers, Fort Bend, Galveston, Hardin, Harris, Jefferson, Liberty, Montgomery, Orange, and Waller counties).

Public hearings were held in Houston on December 14, 1992, and Beaumont on December 15, 1992 to consider the proposed revisions. Written comments were accepted through February 15, 1993 Forty-three commenters submitted written testimony Thirteen commenters presented oral testimony during the public hearings. All testimony and written comments have been reviewed and seriously considered The following discussion addresses the general comments and suggested corrections and then addresses the comments specific to each part of the regulation

Endorsement/Support. Amoco Chemical Company (Amoco Chem), Amoco Oil Company (Amoco Oil), and Chevron U S A Products Company (Chevron) encouraged the continued joint meetings of the Texas Air Control Board (TACB) and industry work groups The meetings between TACB staff and the Texas Chemical Council (TCC) Nitrogen Oxides NO_x RACT Subcommittee, equipment vendors, trade associations, and other industry representatives since early 1992 have been very productive in the preparation of the first round of NO_x RACT rules. Much work still remains in the further drafting of regulations, and the spirit of cooperation developed to date will be instrumental in meeting air quality goals in the future.

Amoco Chem, Amoco Oil, and Chevron expressed support for flexible, innovative approaches to emission reductions. In the current round of NO_x RACT rulemaking, the staff has sought to develop rules which incorporate flexible and innovative approaches while accomplishing reductions which will benefit air quality. Future rulemaking efforts should continue to promote creative solutions which meet both these goals.

Destec Energy, Inc. (Destec) expressed support for the proposed rule and commended the TACB staff for its judicious use of a well-balanced advisory group. The staff acknowledges the commendation extended by the commenter.

Amoco Chem, Amoco Oil, Chevron, Dow U.S.A. (Dow), DuPont, Exxon Chemical Americas (Exxon Chem), Mobil Oil Corporation (Mobil), Monsanto, and Texaco Chemical Company (Texaco) endorsed the comments submitted by the TCC and/or the Texas Mid-Continent Oil & Gas Association (TMOGA). The staff has noted individual commenters' endorsements of TCC and TMOGA comments.

Technical/Benefits. OxyChem (Oxy) recommended that the TACB exercise caution in implementing NO_x RACT rules because of uncertainty in NO_x/volatile organic compounds (VOC)/ozone relationships. The 1990 Federal Clean Air Act (FCAA) Amendments, §185(B), required the EPA to conduct a study on the roles of NO_x and VOC in ozone formation. Two major components of this study, a report by the National Academy of Sciences titled Rethinking the Ozone Problem in Urban and Regional Air Pollution (December 1991) and a draft EPA report titled **The Role of Ozone Precursors in Tropospheric Ozone Formation and Control** (February 1993) concluded that NO_x controls are generally more effective than VOC controls in reducing ozone in areas where ambient VOC/NO_x ratios are relatively high The study cautioned, however, that control strategies must be tailored to individual areas because of variations in ozone response to reductions in NO_x and/or VOC VOC/NO_x ratios obtained from ambient air measurements in the Houston/Galveston and Beaumont/Port Arthur areas are well above the 15-20 range generally considered to indicate greater effectiveness of NO_x controls over VOC controls in the reduction of ozone These data point out the importance of implementing NO_x controls in the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas as soon as is practicable In these areas, the Urban Airshed Model (UAM) will likely be instrumental in fine-tuning the ozone control strategy, not in deciding whether to implement NO_x controls at all Due to relatively lower VOC/NO_x ratios in Dallas/Fort Worth and El Paso, the TACB decided to delay NO_x RACT rules for these ozone nonattainment areas until UAM results were available to assist in determining whether such a strategy would be effective in reducing ozone in these areas.

Oxy commented that implementing NO_x RACT rules before the need is demonstrated by UAM modeling will result in unnecessary expense to industry, even if rules are rescinded later. The Federally mandated schedule for attainment of the ozone standard sets ambitious, but achievable timelines for implementing controls in ozone nonattainment areas. Results of UAM modeling will play an important role in determining the extent and magnitude of needed NO_x reductions. However, the time required to set up, run, and perfect these sophisticated models does not allow the luxury of having all the answers before beginning to undertake emissions reductions. The most cost-effective and feasible control measures should be implemented whenever there is a reasonable expectation that improvements in ozone levels will result. As noted in the response to the previous comment, the TACB has already postponed consideration of NO_x RACT rules for Dallas/Fort Worth and El Paso in order to weigh UAM results heavily in developing NO_x RACT policy for these areas. Available information, notwithstanding future UAM results, indicates that NO_x reductions in the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas will be highly effective in reducing ozone levels. Results of first-round UAM modeling will be available to confirm the direction of the NO_x control strategy before initial control plans are required to be submitted by industry by April 1, 1994. Besides the primary benefit of emissions reductions, the proposed NO_x RACT regulation will also enhance the emissions inventory and input to the UAM model. The regulation's compliance schedule requires preliminary testing data for the majority of NO_x emission sources to be submitted with the initial control plan by April 1, 1994. This will allow the NO_x inventory enhancement to be included in the UAM reevaluation of 1995. The staff believes that proceeding with NO_x RACT rules in an expeditious manner is justified for these reasons.

The Galveston-Houston Association for Smog Prevention (GHASP) commented that maximum emission reductions are needed because Houston is classified as a severe ozone nonattainment area. The staff agrees that substantial NO_x reductions will likely be required in order to attain the ozone standard in the Houston/Galveston and the Beaumont/Port Arthur ozone nonattainment areas. However, there are practical technical and economic considerations in the implementation of a rule of this scope that point to phasing-in progressively more restrictive standards over time. The first round of NO_x RACT rules in the current proposed rulemaking represents a significant step toward attaining the ozone standard. The staff estimates that this first round of rules will result in NO_x reductions on the order of 20% from major stationary sources and 10% overall As more information becomes available from emissions testing of industrial boilers and heaters, and the results of UAM modeling are evaluated, the staff will be able to determine further needed NO_x reductions and initiate the next round of rulemaking.

Oxy suggested that the staff conduct studies to evaluate the need for further NO_x controls. Air quality dispersion models are the primary tool currently available to states in predicting the effects of proposed emission controls on ambient ozone concentrations. In fact, EPA requires the use of photochemical grid models such as the UAM to demonstrate attainment of the ozone standard or to justify exemption from NO_x RACT requirements. The UAM is not perfect, however, and relies upon the quality of inputs such as emissions data in order to produce accurate, meaningful results. The emissions data to be collected and submitted by industry as a result of the current proposed NO_x RACT rules will be extremely valuable to the staff in enhancing the accuracy of the emissions inventory and the UAM. The EPA is currently conducting studies to improve the reliability of the UAM, and will make this information available to states. In the meantime, actual data from sources affected by the rule will be very useful to the staff in assessing the need for further NO_x controls.

Miscellaneous. EPA commented that the staff should issue a technical support document explaining the derivation of all RACT limits. The staff intends to prepare a brief technical discussion as part of the NO_x RACT State Implementation Plan (SIP) submittal which will provide the basis for the rule's RACT limits.

EPA commented that the staff should indicate whether all major NO_x sources are covered by the rule, and if not, provide EPA with a schedule for future rule adoption. The staff's responses to hearing testimony identify major source categories and other areas which will require further rulemaking to comply with the NO_x RACT portions of the FCAA Amendments. The EPA has pointed out in its hearing testimony some of these areas requiring more work, and communications are ongoing to provide EPA with information concerning future rule adoption.

TMOGA suggested that the staff publish a position paper in the *Texas Register* as a preamble to the rule. This technical issues paper will be available to the public after the NO_x RACT SIP is submitted to EPA.

GHASP objected to a block one-hour average throughout the rule, and commented that the rolling one-hour average in the June 1992 draft proposal was more stringent. The block one-hour averaging period for gas turbines, internal combustion engines, and boilers and heaters without continuous emission monitoring systems (CEMS) installed has been retained. A 24-hour rolling average for adipic acid and nitric acid plants is required. For boilers and heaters with CEMS, a 30-day rolling average in pounds of NO_x per million British thermal unit (Btu) (lb NO_x/MMBtu) or a block onehour average in pounds per hour (lb/hr) is required. The staff believes that extending compliance averaging periods will not compromise air quality goals, but will provide flexibility necessitated by the fluctuation of operating parameters and emissions over time. The June 1992 draft proposal of the rule did not contain any reference to a rolling one-hour average.

Organization of Rule/Errata. TCC suggested replacing the word "biennial" with "every two years" in §117.213(d), relating to Continuous Demonstration of Compliance, and in other places where the word occurs. The staff considers the standard dictionary definition of the word "biennial," defined as "occurring every two years," to apply throughout the rule wherever this word is used.

In §117.119(d)(5), EPA suggested adding the word "otherwise" after "unless" in the phrase "... unless requested by the Executive Director of the TACB." The word "otherwise" has been added to the referenced sentence in §117.119(d)(5), relating to Notification, Recordkeeping, and Reporting Requirements. This revision would also apply to wording in parallel sections of the rule at §§117.219(d)(5), 117.319(c)(5), and 117.419(c)(5).

EPA commented that in §117.203(b)(6)(C), relating to Exemptions, the requirement for sources with withdrawn exemptions to submit a revised compliance plan conflicts with the lack of a requirement for these sources to submit an initial or final compliance plan. The word "revised" will be deleted from §117.203(b)(6)(C), thereby clarifying the requirements for submitting a compliance plan. In §117.207(f), EPA suggested to refer to "low annual capacity factor boilers or process heaters" (additions underlined) to be consistent with the definition of this term in §117.010, relating to Definitions. The suggested wording has been incorporated into §117.207(f), relating to Alternative Plant-Wide Emission Specifications.

EPA commented that in §117.207(f), relating to Alternative Plant-Wide Emission Specifications, and §117.211(c)(4),(5), and (6), relating to Initial Demonstration of Compliance, the citation of §117.203(6), relating to Exemptions, as a definition of low capacity factor units is incorrect, since the exemption of gas turbines or engines in §117.203(6) is based on annual hours of operation rather than capacity. The staff believes that the term "low annual capacity factor" may be properly used to describe operations of emissions units on the basis of either annual fuel consumption or annual hours of operation. Therefore, the wording "low annual capacity factor gas turbine" and "low annual capacity factor gas engine" is added to §117.203(b) (6)(B), to clarify that the exemption is based on annual hours of operation. The reference to §117.203(6) in §117.203(b)(6)(B) in the applicable sections has also been changed.

EPA commented that the term "low annual capacity factor units" in §117. 211(c)(4), relating into Initial Demonstration of Compliance, is not defined for gas turbines, and that §117.10, relating to Definitions, defines the term only for boilers and process heaters. The reference to low annual capacity factor units in §117.211(c)(4) is to gas turbine supplemental waste heat recovery units, not gas turbines. The term "low annual capacity factor gas turbine supplemental waste heat recovery unit" is added to the title of the definition of "low annual capacity factor boiler or process heater" in §117.10, as well as to §117.211(c)(4).

DuPont and EPA suggested in §117.321 and §117.421, relating to Alternative Case Specific Specifications for adipic acid and nitric acid plants, respectively, that the reference to plant-wide averaging be deleted since this option is not available for adipic acid and nitric acid plants. The reference to plant-wide averaging in both §117.321 and §117.421 has been deleted.

EPA commented that the applicability of the undesignated head "Nitric Acid Manufacturing" is confusing, since §117.401, relating to Applicability, applies only to nitric acid plants in the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas, whereas the undesignated head "Nitric Acid Manufacturing-General" applies statewide. The title of the undesignated head "Nitric Acid Manufacturing" has been changed to "Nitric Acid Manufacturing-Ozone Nonattainment Areas." The wording in the undesignated head "Nitric Acid Manufacturing-General" has been clarified by deleting the word "only" in the last sentence of §117.451, relating to Applicability.

Section 117.10-Definitions. Some commenters requested the inclusion of definitions in §117.010 which were not part of the original proposal. The Administrative Procedure and Texas Register Act (APTRA) does not allow adoption of a rule which contains major substantive changes from the original proposal as published in the *Texas Register*, although a rule may be reproposed and reoffered for public comment. The Secretary of State's Office has interpreted this to mean that no new definitions can be added to the rule at this time. In order to clarify the staff's intended meaning, comments requesting new definitions will be addressed in the staff's responses in this section. New definitions may be proposed in future rulemaking.

TCC recommended adding five definitions to be consistent with EPA Region 6 terminology: emission rate, facility cap, mass emission loading, maximum allowable emission rate, and maximum allowable mass emission loading. TMOGA suggested a definition for facility cap. GHASP recommended that a definition of emission rate be included which includes emissions from start-ups and shutdowns. The staff is not sure that the proposed TCC definitions would add clarity to the rule. For instance, emissions in lb/hr are usually referred to as "mass emission rate," rather than mass emission loading. Rates can be per unit of energy or per unit of time. The staff believes that emission limits are clearly expressed as proposed. The staff may recommend definitions relating to facility caps in future rulemaking.

GHASP's suggested definition of emission rate is based on the concern that emissions may not be minimized during periods of start-up and shutdown. The staff believes that clarifying the definitions of start-up and shutdown to improve the consistent application of General Rule §101.11(b) could lead to reduced emissions, whereas changing the definition of emission rate is a less effective way of addressing the concern. The TACB Compliance staff intends to develop more uniformity in defining periods of start-up and shutdown and evaluating emissions occurring during start-up and shutdown periods based on comparisons of data within specific facility types.

Texaco commented that the definition of "block one-hour average" is vague, since it doesn't specify the frequency or quantity of data to be collected each hour. The staff relied on current federal New Source Performance Standards (NSPS) as a guide in drafting the proposed rule requirements for emissions testing and monitoring The General Provisions (Subpart A) of NSPS, §60.13(h), require four or more data points equally spaced over each one-hour period. However, if three valid data points can be generated during the hourly period in which the once-per-day zero and span checks are performed, hourly emission are to be calculated from this data. This relatively low frequency of data collection will facilitate sharing of CEMS, thereby reducing total CEMS costs. The staff does not expect that the Title V enhanced monitoring requirements will entail major revisions to NSPS CEMS requirements, but understands that any additional Title V CEMS requirements would be applicable to major NO_x sources. The staff has reviewed EPA's preliminary draft-enhanced monitoring rules and will review the rules again when they are formally proposed in the *Federal Register*. Although the staff believes that the new Chapter 117 provides sufficient details to adequately specify procurement of CEMS, the staff intends to provide, before the end of the summer, brief written guidance on testing, monitoring, and acceptable formats for initial compliance plans.

TCC and TMOGA suggested that a definition is needed for "chemical processing gas turbine" and suggested that it be defined as a gas turbine employed as a power source within, or integral to, a chemical processing unit. The staff proposed a definition for "chemical processing gas turbine" as "a gas turbine that vents its exhaust gases into the operating stream of a chemical process." The basis for the staff's proposal and exemption for such turbines at §117 203(b)(6)(A) is that a downstream chemical process, typically consisting of catalyst beds which rely on hot exhaust gases from a turbine functioning as a hot air generator, could be adversely affected by the presence of steam or water injection for NO_x control in the exhaust gases. "Chemical processing gas turbines" as proposed in the definition are relatively rare. TCC's and TMOGA's recommendation would exempt turbines used for mechanical or electric power output, which are the typical uses of gas turbines. The definition will be maintained as proposed.

TCC and Houston Lighting & Power (HL&P) suggested that the definitions for cold start-up and shutdown be deleted. Amoco Chem, Amoco Oil, Exxon Chem, Exxon Company, U.S.A. (Exxon), Gulf States Utilities Company (GSU), and Enron Power Corporation-U.S. (Enron) suggested various revisions to the definitions for cold start-up and shutdown. Section §101.11(e) provides a mechanism for exemption of a process from emission limits during periods of start-up or shutdown. This subsection is written broadly in order to cover all types of sources. The staff believes it is appropriate to clarify the application of §101.11 in the more specific context of combustion sources in Chapter 117. The staff also believes that the proposed definitions of cold start-up and shutdown are simple, clear, and appropriate. The variety of comments as to what conditions constitute a startup or shutdown suggests that there is a need for clarification. However, the staff did not thoroughly discuss the proposed definitions internally or with industry and does not believe this issue must be resolved under the current rulemaking. Further, the staff is interested in consideration of specific numerical time limits for defining start-up and shutdown for each category of equipment regulated under the rule. Due to the need for future clarification, the proposed definitions of cold start-up and shutdown have been deleted.

TMOGA and Mobil suggested a definition for CEMS as an analytical device that directly measures and records specific emissions, such as NO_x, for one or more combustion devices at least four times each hour. Exxon Chem suggested a similar definition for CEMS. The first paragraph of §117.10 states that terms not specifically defined in the Texas Clean Air Act, the General Rules, or this chapter shall have the meanings commonly used in the field of air pollution control. Although the suggested new definition appears fairly consistent with the staff's intent, the staff does not believe that a definition for CEMS is required, since the meaning is commonly understood in the field of air pollution control. The staff recommends limiting the number of units sharing a single CEMS to three. Hourly CEMS data collection requirements were discussed in the previous response to the definition of block one-hour average. The NSPS CEMS performance specification tests and quality assurance requirements referenced at §117.213(b), §117.313(b), and §117.413(b) further define CEMS.

HL&P suggested deleting the names of affected companies in the definition of "electric power generating system." The staff's use of names of affected companies was intended for clarity. The staff does not believe that confusion will result from deleting the specific utility names if "publicly regulated utility" is substituted for the two names. The intent is that cogeneration sources be regulated under the undesignated head, "Commercial Institutional and Industrial Sources." Since cogeneration sources are not regulated by the Public Utility Commission of Texas, no confusion should result. The names "HL&P" and "GSU" have been deleted from the definition.

Exxon suggested that the definition of heat input be modified to include a definition for the heat input of a carbon monoxide (CO) boiler in a fluid catalytic cracking unit (FCCU). The staff recognizes the need to define heat input of an FCCU CO boiler. The staff agrees with Exxon and the definition of heat input has been revised to include the South Coast Air Quality Management District (SCAQMD) rule-language, as suggested by Exxon for CO boilers.

Waukesha Engine Division (Waukesha) suggested using an engine's nameplate rating to define engine horsepower. The TACB has previously encountered controversy over claims that nameplates have been altered in an attempt to circumvent the requirements of the TACB. Nameplate ratings do not always reflect the load limitations that the driven equipment may impose on an engine. The staff recognizes the commenter's concern that gas engine manufacturers may not have used Diesel Equipment Manufacturer's Association standards in describing their engines' horsepower capabilities and that to require this standard could be costly. The definition of horsepower rating referenced in Standard Exemption 6 appears to be a workable definition. The second sentence of the definition of horsepower rating has been deleted, making the proposed definition equivalent to the existing definition in the TACB Standard Exemption List.

TRC Environmental Corporation (TRC) for Applied Energy Services (AES) Deepwater commented that the definitions of "utility boiler or steam generator" and "electric power generating system" do not include AES' petroleum coke-fired boiler. TRC suggested that the definition of industrial boiler or steam generator does not apply to AES, since petroleum coke is a waste fuel. AES' boiler is not owned or operated by a municipality or a Public Utility Commission of Texas-regulated utility, so it is neither a "utility boiler or steam generator," nor an "electric power generating system." The staff intends that the definition for industrial boiler or steam generator apply to petroleum coke-fired industrial boilers or steam generators. The definition states that an industrial boiler or steam generator is any combustion equipment, not including utility or auxiliary steam boilers, that burns solid, liquid, or gaseous fuel to produce steam. The staff considers petroleum coke, which is a solid and is used as a fuel, to be a solid fuel, so the definition would apply to this type of unit for the purposes of this rule. The unit would, therefore, be regulated under the undesignated head "Commercial, Institutional, and Industrial Sources."

TCC noted that the definition of low annual capacity boiler and process heater has subparagraphs (A) and (B) reversed. The definitions are used to define rule exemptions for equipment which is used sparingly. The staff originally based the definition on the potential of a unit to be a major NO_x emitter. The staff believes that subparagraphs (A) and (B) are not reversed, since the staff developed the proposed definition using an emission factor of 0.14 lb NO_x/MMBtu for units rated less than 100. 0 million Btu per hour (MMBtu/hr) heat input, which was half the factor used for large units rated more than 100.0 MMBtu/hr heat input.

Since the proposal was published, the staff has reconsidered cost effectiveness in setting the heat input exemption threshold for large units. For large units, the staff used an emission rate of 0.23 lb NO_x/MMBtu, which is EPA's typical emission factor for natural gas-fired boilers in the NSPS Subpart Db Preamble (49 Federal Register 25106). Using this emission factor, the staff calculated that an industrial boiler or process heater with a heat input of 100.0 MMBtu/hr and operating at a 25% annual capacity factor is a potential major source of NO_x. The annual heat input for such a unit is 2.2(10NO$_{11}$) Btu/year. The staff considered the cost-effectiveness of emission controls on a unit with these characteristics, based on the California Air Resources Board (CARB) and SCAQMD technical support document, *A Suggested Control Measure for the Control of Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators and Process Heaters* (April 1987). The document computes cost-effectiveness of NO_x controls as a function of the annual capacity factor of a unit. Capital costs for NO_x control equipment are independent of capacity factor. Annual emission reductions, and hence cost-effectiveness, are highly variable with the capacity factor. As examples, two "D" type package boilers with substantially differing ease of retrofit have NO_x cost effectiveness values of $1, 000/ton (simple retrofit case) and $2,800/ton (difficult retrofit case) of NO_x reduced, based on a 25% annual capacity factor. The staff considers these costs to be reasonable. The CARB document also shows that there are economies of scale in the costs of retrofitting a boiler with a low NO_x burner as boiler size increases. The staff thinks the economy of scale in retrofitting low-NO_x burners (LNB) and the higher emission rates from larger units makes an exemption based on annual heat input cost-effective for increasing unit sizes above 100.0 MMBtu/hr heat input. Based on this analysis, the threshold has been increased for the exemption of low annual capacity factor boilers and heaters rated more than 100.0 MMBtu/hr heat input. The staff has changed the definition of low annual capacity factor boiler or process heater with maximum rated capacity greater than or equal to 100.0 MMBtu/hr heat input from an annual heat input of 1.4(10^{11}) Btu/year, to 2.2(10^{11}) Btu/year. The Btu/year exemption threshold for the units with maximum rated capacity greater than or equal to 40.0 MMBtu/hr and less than 100.0 MMBtu/hr heat input has been retained.

HL&P suggested that the definition of maximum rated capacity be reworded so as to not constrain existing boilers and turbines. It suggested defining maximum rated capacity as the maximum heat input as documented by actual operation. It suggested the TACB Permits practice of using the lowest temperature, perhaps ten degree Fahrenheit, to establish maximum rated capacity for gas turbines.

The maximum rated capacity is used to establish emission limits, but does not place new constraints on production capacity of units. Independent and prior to the proposed Chapter 117, each unit has a production constraint based on actual grandfather production rate or permit condition. If the unit is grandfathered (with respect to TACB Chapter 116), defining maximum rated capacity as the maximum heat input as documented by actual operation (prior to September 1, 1971) is appropriate. If the unit is permitted, a permit condition or representation in the permit application, or the design maximum heat input would represent the production constraint. The maximum rated capacity definition is meant to coincide with the current production constraint for boilers and heaters. The maximum rated capacity definition is not meant to coincide with the current production constraint for gas turbines and internal combustion engines (ICE). However, the gas turbine emission limits are in parts per million (ppm) for base-load turbines or pound per million Btu for peaking turbines at §105(h); and for ICE, in grams NO_x per horsepower-hour (g NO_x/hp-hr). Limits of this nature do not constrain production and the maximum rated capacity definition is irrelevant, except in the case of calculating alternative limits under the system-wide average (or plant-wide average for industrial sources).

The maximum rated capacity definition is designed to avoid inflating the weight of gas turbines (or ICE) in the system-wide (or plant-wide) limit. The maximum rated capacity definition for gas turbines and ICE treats this equipment slightly differently from boilers on the basis of a physical difference in the way they operate. Gas turbine and ICE maximum output increases significantly as ambient temperature decreases. For turbines, extremely cold temperatures are the appropriate basis for establishing a permitted production-based maximum pound per hour emission rate; however, the level of control required is entirely established by a ppm limit. The system-wide average uses a heatinput weighted average to determine individual unit allowable emissions. By using the International Standards Organization (ISO) basis for determining the gas turbine heat input weighting factor (and manufacturer's horsepower rating for ICE), the system-wide emission limits are not artificially weighted with extreme cold operating conditions which occur very rarely. To ensure that the system-wide average limits result in RACT equivalent reductions to individual emission limits, a logical argument could be made for using an even higher ambient temperature, perhaps based on average ozone exceedance day temperature. This temperature is not readily available, whereas ISO temperature (59 degree Fahrenheit) is, and turbine output at ISO temperature reasonably approximates maximum output under ozone exceedance conditions

TMOGA, Exxon Chem, and Miles Incorporated (Miles) suggested a definition for parametric monitoring system. The requirement to install, calibrate, maintain, and operate a parameter monitoring system has been deleted from §117.213(a).

EPA suggested that a definition be added for the term "peaking service" or clarify the language of §117.103(b)(3)(C) and §117.203(b)(6)(C) if the intent there is that a unit "in peaking service" is the same as a "peaking gas turbine or engine." The wording of §117.103(b)(3)(C) and §117.203(b)(6)(C) has been revised to parallel the definition of "peaking gas turbine or engine."

TMOGA and Mobil suggested deleting the wording "the ratio of the" in both the definitions of plant-wide emission rate and plantwide emission limit The staff based the definitions of plantwide emission limit and plant-wide emission rate and the use of these terms in §117.207 (similarly for system-wide in §117.105) on SCAQMD Rule 1109, which also relies on emissions averaging with individual unit emission limits Companies will be allowed to assign individual heater and boiler NO_x emission limits in either lb/hr, one-hour average, or lb NO_x/MMBtu, 30-day rolling average, as discussed in §117.207 The staff believes this flexibility may address the concern of the commenter and does not believe that the suggested wording change would add clarity to the definition. The staff intends to provide a brief guidance document for companies to develop their initial compliance plans and may restate the emissions averaging concept using mathematical notation rather than the verbal approach based on Rule 1109.

Oxy interpreted the definition of process heater to exclude thermal reactors and suggested that TACB clarify this definition accordingly. Oxy also suggested that the exclusion of thermal cracking units would be appropriate because, according to the EPA's assessment, they are not a significant class of NO_x sources. The staff has defined process heaters in a way that includes thermal cracking units in the equipment class of process heaters. The definition states that a process heater is a piece of combustion equipment which is used to transfer the heat from the combustion of liquid or gaseous fuels to a process fluid. The definition does not make judgement as to whether or not the heat transferred to the process fluid is for heating the process fluid or for causing a reaction. For this reason, thermal cracking units would be defined as being a process heater and would be subject to the emission limits set forth in Chapter 117. The staff definition of process heater is consistent with the definition in EPA's Alternative Control Technique (ACT) document, *NO_x Emissions from Process Heaters*. The ACT defines process heaters to include heated-feed and reaction-feed heaters. The ACT also shows that reaction feed-heaters account for 80% of the total fired heat input in the chemical manufacturing industry.

TCC, TMOGA, Exxon Chem, and Texaco sought a definition for totalizing fuel flow meter and suggested various definitions. The staff believes that the suggestion for a definition of totalizing fuel flow meter is valid, although it was not originally proposed by the staff in the proposed rule. The staff may recommend that the definition be added in future rulemaking. The definition would be as follows: A nonresettable device that reports cumulative fuel flow to a piece of equipment as the heat value or mass delivered over a defined period of time The staff's interpretation of the definition is that the flow meter must either have a nonresettable mechanical output, or a transducer which will allow the fuel flow rate to be electronically transmitted through an integrated electronic measuring system to a computer for fuel usage recording A strip or chart recorder whose output is not integrated and reported would not qualify as a mechanical output since the reading would not indicate cumulative flow

Utility Costs-General HL&P noted that Subchapter B Combustion at Existing Major Sources-Utility Electric Generation does not treat the same sources consistently for different classes of owners The staff has tried to address both the general and specific situations where HL&P suggested there was inequitable treatment between different classes of owners Some differences between rule sections may be inevitable due to the differences in the type of facilities involved

Greater Houston Partnership (GHP) noted that Subchapter B is costly, especially to utilities

The staff agrees that the subchapter is costly, but believes that attainment of the national ozone standards in Houston and Beaumont/Port Arthur will require the allocation of resources to pollution control projects not previously considered. Cost estimates for rule compliance vary widely, but the staff believes that some of the industry estimates are inflated.

Section 117.101-Applicability. HL&P suggested that the names of the affected companies be deleted from §117.101. The names have been deleted.

Section 117.103-Exemptions. GHASP suggested deleting the exemptions allowed under §117.103(a) for the start-up and shutdown of a unit. Utility boilers are normally infrequently operated in shutdown or start-up modes. Start-ups and shutdowns are shortterm, transient events for which emission control is difficult; emissions from these events are relatively small and will be controlled by existing provisions in the General Rules concerning major upsets and maintenance.

HL&P recommended deleting the reference to "cold start-up or shutdown" and the 12-hour start-up restriction. GSU recommended that the duration of "start-up" and "shutdown" procedures subject to exemptions be extended to 72 hours. HL&P suggested that §117 103(a) should also reference the system-wide averaging provisions of §117.107. The staff proposed a specific 12-hour maximum time period for start-up procedures for all electric utility units The time period was based on the SCAQMD utility NO_x rule, where the definition applies only to utility power boilers, not utility auxiliary boilers, gas turbines, or engines The 12-hour time period may not be appropriate for other units such as gas turbines, which may start-up in minutes. The staff does not believe start-up periods must necessarily be fully defined under the current rulemaking, since the General Rules make allowances for exempting units during periods of major upsets and maintenance. Section 117 103(a) has been revised so that start-up and shutdown periods, as defined in the General Rules, will apply.

GSU stated that TACB should exempt sources which are determined not to contribute to ozone nonattainment in their respective areas. The staff disagrees with GSU To consider the concept of exempting certain "non-contributing" sources would imply that ozone formation is generally caused by specific emission units. This premise is unsupported by decades of scientific research concerning photochemical oxidants and smog In fact, photochemical smog is a regional problem to which all sources, particularly electric utility plants, contribute During smog episodes, ozone tends to build slowly over time, so that more sources contribute to the problem, over a much wider area, than for other criteria pollutant emissions. The available evidence on ozone formation points out the inherent difficulties in placing arbitrary borders around a problem which does not recognize geographical boundaries.

GHASP opposed the §117 103(b)(3)(C) exemption for gas turbines used in peaking service.

Stationary industrial engines and turbines often run either close to continuous operation or less than 10% of annual capacity, about 850 hours per year Requiring emission controls for equipment which is limited to run no more than 10% of annual capacity is not cost-effective. Considering the magnitude of NO_x emissions generated continuously by other sources on a year-round basis, the exemption of the relatively few peaking units for the reasons cited appears reasonable The annual low capacity factor for both utility and industrial gas turbines and internal combustion engines has been raised to 850 hours per year. Rule sections relating to exemptions for both utility and industrial sources, and continuous demonstration of compliance have been revised to reflect this change

EPA suggested that the exemption for peaking turbines in §117 103(b)(3)(C) be based on operation for less than 200 hours per **calendar** year.

The language is revised in §117 103(b)(3)(C) as suggested.

HL&P strongly urged the TACB to exempt auxiliary boilers with a heat input of less than $8.76(10^{11})$ Btu per year. Industrial boilers with a heat input capacity of less than 100 0 MMBtu/hr heat input are not subject to a NO_x emission limit under Chapter 117 Industrial boilers with heat input less than 100.0 MMBtu/hr could consume up to $8.76(10^{11})$ Btu per year. HL&P is concerned that the proposed exemption may require emission controls for units which rarely operate, which is not cost effective. There are eight utility auxiliary boilers in the four ozone nonattainment areas, all operated by HL&P. The staff's analysis of 1990 emissions data revealed that only two of the eight affected auxiliary units would not be exempted under the current proposal, and that 1990 capacity factors were unusually high for those two units. The use of historical capacity factors in the analysis revealed that exemptions might potentially apply for all eight affected auxiliary units. Nonetheless, TACB has reconsidered cost effectiveness in setting the heat input, based exemption for industrial boilers and heaters. The annual heat input exemption for utility units has been increased to the level now recommended for industrial units.

EPA's direction to TACB is that Chapter 117 should address all major sources. Smaller industrial boilers, those with maximum rated capacities less than 100 MMBtu/hr heat input, are potentially major sources Although the proposed rule exempts such sources from emission limits, the staff recommends proposing rules for these and other major sources in additional rulemaking in the near future. The staff does not believe that the need for supplementary rulemaking in the future for regulation of smaller major sources is justification for exempting major sources which are subject to the current rule. HL&P observed that §117.103(c) indicates that if emergency, standby, or peaking units exceed the applicable Btu-per-year or hour-per-year limitation, the exemption will be withdrawn. HL&P requested at least one exceedance before the exemption would be withdrawn. Alternatively, HL&P recommended that a three-year rolling average for the Btu-per-year limitation could be adopted to help sources avoid having exemptions withdrawn due to emergency situations. GSU recommended that a three-year rolling average for the Btuper-year limitation be adopted to help sources avoid having exemptions withdrawn due to emergencies. Chapter 117 requires application of emission controls if the exemption levels are exceeded. The cost-effectiveness of any emission controls decreases as the amount of time the equipment operates decreases. The staff has increased the allowable hourly limitations from 200 to 850 hours per year in order to assure that the equipment in the specified services either meets the exemption from control requirements or is required to have controls applied where it may be cost-effective. The staff also has increased the allowable annual heat input for the low annual capacity factor (Btu-per-year) exemption. Otherwise, installation of NO_x controls could be required in cases where it may not be cost-effective The staff feels that allowing an exceedance of a limit defeats the purpose of setting a limit, so HL&P's potential solution is not recommended. Allowing a three-year rolling average Btu-per-year limitation is another potential solution to the problem However, enforcement of emission limitations on such a long-term basis may not be acceptable to the EPA. The staff has increased the hour-per-year and Btu-per-year exemption limits, as discussed in the previous comment and has raised the hourly limits in the utility rule to be consistent with revisions in the industrial rule.

If the exemption is lost, HL&P recommended a 90-day (instead of 30-day) period, and GSU recommended a 180-day period, to develop and submit a compliance plan.

The staff agrees that the time period should be extended and has increased the proposed 30-day limit to a 90-day limit to develop and submit a compliance plan.

Section 117.105–Emission Specifications. HL&P stated that in §117.105 the staff has failed to follow the RACT guidance available from the EPA. EPA recommended NO_x RACT limits for utility boilers in the November 25, 1992 **NO_x** Supplement to the General Preamble. Their suggested RACT limits are 0.20 lb NO_x/MMBtu for tangential-fired and 0.30 lb NO_x/MMBtu for wall-fired electric utility boilers, calculated on a 30-day rolling average basis. However, the guidance also states, "Although EPA has historically recommended source-category-wide presumptive RACT limits..., decisions on RACT may be made on a case-by-case basis, considering the technological and economic circumstances of the individual source (57 Federal Register 55624)." Staff has interpreted EPA's guidance to allow different RACT determinations to be made, as appropriate, based on affected sources' and states' individual circumstances. Thus, the proposed RACT limits do, in effect, follow EPA's guidance, since it allows more specific RACT determinations. EPA's guidance is designed for outliers or the very highest emitters and as a result, the Texas boilers would not achieve any additional reductions if EPA's RACT limits were applied. The system-wide mean emission rate for HL&P's gasfired boilers has been estimated at about 0.23 lb NO_x/MMBtu which suggests compliance with a limit of 0.25 lb NO_x/MMBtu on a 30-day rolling average, but the system-wide emission limit, applying EPA's RACT guidance to HL&P's boiler population, is 0.28 lb NO_x/MMBtu, averaged over 30 days. If the presumptive RACT limits were adopted, HL&P would already be in compliance with the emission limits according to the staff's calculations, and the needed emission reductions would not be achieved. The TACB proposed emission limits are also based on a shorter averaging period than EPA's, which is effectively a more stringent limit. HL&P data shows that the proposed 24-hour averaging period may be 29% more stringent (i.e., NO_x emissions variability from the arithmetic mean is plus 29%) than EPA's suggested 30-day averaging period, based on actual monitored emissions data from two of HL&P's gas-fired units. If EPA's numerical limits were applied on a 24-hour average basis instead of the 30-day average that EPA recommends, it is estimated that HL&P would still be in compliance with the EPA's presumptive RACT limits and would not require controls. The staff recognizes that the proposed §117.105 emission limits are more stringent than the EPA's recommended limits, but believes this is necessary to make progress toward attainment of the ozone National Ambient Air Quality Standard (NAAQS) by the federally imposed deadlines.

Ozone attainment will require a major effort by broad categories of industries, and a cooperative effort between government and industry. The single largest major NO_x stationary point-source category in Texas is the electric utility industry, which accounts for more than 25% of the major source NO_x emissions in the four ozone nonattainment areas. The utilities must bear some of the cost of reducing NO_x emissions if attainment is to be achieved by the statutory deadlines.

HL&P claimed to be required to spend an estimated $790 million to satisfy the requirements of the proposed rules. They stated this will place their company in a less competitive position with respect to local power producers. HL&P noted that their costeffectiveness estimates are $8,600 per ton of NO_x reduced. The TACB staff believes the estimated $790 million dollars to comply with proposed 0.20 lb NO_x/MMBtu emission limits is exaggerated. It includes costs to replace a net 640-megawatt (MW) loss in generating capacity as a result of RACT operational requirements, primarily associated with furnace pressure limitations reached through the extensive use of windbox flue gas recirculation (FGR) control technology. A thorough review of the requirements as applied to HL&P revealed no conclusive evidence that derating would be necessary on all of HL&P's units, as theorized. Admittedly, the postulated derates for furnace pressure limitations could occur for the technical reasons cited; in fact, units can be found elsewhere in the United States that have experienced derates for similar reasons. However, no conclusive evidence was found that derates of the magnitude they suggested, for virtually all of their units, was a probable scenario. The staff independently developed capital cost estimates to comply with the proposed rule of $32 million under one control scenario. After reviewing additional information submitted by HL&P, the staff developed a $73-million scenario based on the comprehensive application of low NO_x burners. These cost estimates, which were developed without foreknowledge of chosen compliance methods, are imprecise, but the staff believes they represent a more realistic cost range than HL&P's estimates. The staff believes HL&P's cost-effectiveness estimate of $8,600 per ton is too high because it is largely based on excessive capital and derate costs. The staff's cost-effectiveness estimates are $1,300 per ton for the first scenario, and $3, 300 per ton for the scenario using the application of LNB.

HL&P commented that the proposed emission limit, 0.20 lb NO_x/MMBtu for wall and tangential gas-fired utility boilers, calculated on a 24-hour rolling average, doesn't represent RACT, is too stringent, and fails to follow EPA's RACT guidance of 0.20 lb NO_x/MMBtu and 0.30 lb NO_x/MMBtu emission limits for tangential and wall gas-fired utility boilers respectively, calculated on a 30-day rolling average. HL&P recommended that emission rates equivalent to the application of LNB and overfire air be considered RACT. They stated that obtainable emission rates with the application of these techniques are expected to be close to EPA's recommended limits. GSU recommended emission limits of 0.20 lb NO_x/MMBtu and 0.30 lb NO_x/MMBtu for tangential and wall-fired boilers, respectively, calculated on a 30-day rolling average.

As a result of negotiations with HL&P, the staff has adopted NO_x emission limits less stringent than those proposed. Limits of 0.26 lb NO_x/MMBtu for gas-fired utility boilers on a 24-hour rolling average basis and 0.20 lb NO_x/MMBtu based on a 30-day rolling average have been implemented, instead of 0.20 lb NO_x/MMBtu on a 24-hour average basis as originally proposed. The staff has deleted the pound-per-hour mass-emission limit standard. The staff's recommended emission limits are much closer to the recommended EPA limits. For HL&P, the limits may be approximately equivalent to the application of low-NO_x burners. The staff estimates that GSU, with only two operating stations in the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas and lower emitting units than HL&P, currently meets the recommended limits. The staff agreed to compromise to facilitate rulemaking progress while retaining a reasonable level of reductions.

HL&P and GSU stated that the rule imposes the same emission limits on both wall and tangential gas-fired utility boilers without acknowledging the design differences between the two types and their impact on NO_x formation. This is inconsistent with EPA guidance and with existing TACB Chapter 117 NO_x rules. The staff recognizes that tangentially-fired gas boilers are often lower NO_x emitters than wall-fired units. The intent in setting the emission limits was to achieve moderate emission reductions from HL&P's 19 gas-fired boilers considered as a single system. The expected reductions can be achieved by requiring a single limit, for both tangential and wall-fired units, that is derived from an analysis of the different firing configurations in the affected boiler population. The single emission limit simplifies the staff analysis needed to design the appropriate system emission reduction and does not appear to inconvenience HL&P substantially. Tangentially-fired boilers can, in a system-wide average, offset emissions from wall-fired boilers, which are otherwise more costly to control. Since the rule allows system-wide averaging, a single RACT limit for both firing configurations was considered as appropriate as separate limits.

HL&P claimed that the staff did not consider the physical characteristics and constraints of the affected boiler population and that this is inconsistent with EPA's policy for determining RACT. HL&P stated that Texas utility boilers are initially designed to burn natural gas and are therefore built with small, tight furnaces with inherently high heat release rates. In contrast, many of the boilers in the Northeastern States for Coordinated Air Use Management (NESCAUM) region, whose RACT limit of 0.20 lb NO_x/MMBtu for natural gas utility boilers serves as the basis for the TACB proposed limit, are units which are initially designed to burn coal and later converted to burn natural gas. They are characterized by larger, cooler furnaces with lower heat release rates, which allow for flame expansion and cooling, thereby lowering NO_x emission levels. The staff accounted for the physical characteristics of the affected boiler population when proposing the emission limits in §117.105. The design characteristics of HL&P's gas-fired utility boilers were recognized; the staff believes that the recommended 0.20 lb NO_x/MMBtu (30-day average) and 0.26 lb NO_x/MMBtu (24-hour average) emission limits are reasonably achievable and economically feasible. The staff consulted NO_x control experts, utility boiler design engineers, boiler control technology vendors, power plant operations engineers and technicians, and power plant architects/engineers, and found no conclusive evidence that HL&P's boilers can be singled out as inherently troublesome to control. Furthermore, the staff's estimate of achievable emission reductions are based on HL&P's own reported uncontrolled baseline NO_x emission levels. HL&P claims to have uniquely small, tight furnaces with high heat release rates due to their historically extensive use of natural gas as a boiler fuel, resulting in inherently high baseline NO_x levels, which supposedly require more extensive control technology retrofits than most other utility units. Data was provided by HL&P on the volume of the furnace region directly in front of burner rows for each of their units, instead of using entire firebox volumes as defined in §117.10, which made the heat release rates seem extraordinarily large when compared with similar units. Firebox volumes provided by HL&P, and the staff's computation of heat release rates based on these volumes, are shown in TABLE-1 1.

TABLE-1

HL & P's Utility Boilers
Unit Specific Data

Unit	MW	MMBtu/hr	Fire Box volume* (ft^3)	Heat release $MMBtu/hr/ft^3$
CBY1	770	7,000	48,304	0.14
CBY2	770	7,000	48,304	0.14
CBY3	770	7,000	58,320	0.12
GBY5	420	4,030	62,234	0.06
SRB1	180	1,826	47,374	0.04
SRB2	180	2,442	51,600	0.05
SRB3	240	2,442	23,353	0.10
SRB4	240	1,748	51,600	0.03
DWP9	185	1,735	47,373	0.04
WAP1	183	1,735	47,769	0.04
WAP2	183	2,845	74,778	0.04
WAP3	290	5,490	23,368	0.23
WAP4	565	2,200	35,361	0.06
THW2	240	4,500	35,361	0.13
PHR1	490	4,500	35,361	0.13
PHR2	490	4,500	35,361	0.13
PHR3	575	5,500	66,096	0.08
PHR4	770	7,700	48,693	0.16
WEB3	390	3,550	45,527	0.08

*As reported by HL & P upon TACB's request

The staff found data on a boiler, similar in construction to HL&P's Cedar Bayou 3 (CBY3 on the table), that was used as a basis for performance comparisons. This boiler, Ormond Beach 2 (a Southern California Edison (SCE) boiler currently in commercial operation in Ventura County, California), is a unit designed to burn natural gas and has a very high heat release rate, slightly higher than that of Cedar Bayou 3. Ormond Beach 2 has a heat rate input of 7,125 MMBtu/hr (compared to CBY3's heat rate input of 7,000 MMBtu/hr); its furnace volume of 208,450 ft_3 is equivalent to the actual furnace volume (instead of the volume of the region in front of burners, as reported by HL&P for their boilers) of Cedar Bayou 3. Ormond Beach 2 was constructed at almost the same time by the same boiler manufacturer as Cedar Bayou 3. Ormond Beach 2 is currently operating with burners out of service, LNB, and 18% windbox FGR; and is complying with a 125 parts per million by volume (ppmv) which is approximately 0.15 lb NO_x/MMBtu on a 24-hour average emission limit, a notably more stringent emission limit than was proposed under §117.105. It has not been subject to **any** derate due to fan limitations or furnace overpressurization, although forced draft (FD) fan motors were once replaced with variable speed drives, or experienced other operational difficulties of the magnitude that HL&P suggested would occur with their units. At one time, Ormond Beach 2 temporarily operated at reduced boiler load (but did not derate the unit) due to inability to meet its 0.15 lb NO_x/MMBtu emission limit, but boiler capacity was later restored when they met their emission limits. The unit is currently undergoing a replacement of reheat tubes at a cost of approximately $7.5 million due to tube wear. The wear, although a normal phenomenon, was exacerbated by the operation of NO_x control systems, particularly FGR. The staff acknowledges that some incremental increases in maintenance costs may be attributed to FGR, but HL&P's claim of tens of millions of dollars in costs due to operational difficulties associated with NO_x controls are not representative of current spending needed to comply with the rule. Ormond Beach 2 is currently being retrofit with flue gas treatment systems to comply with a new 0.10 lb NO_x/MW-hour emission limit (approximately 0.01 lb NO_x/MMBtu). Although requiring the installation of among the most extensive NO_x control equipment in the nation, its new limit is expected to be achieved without requiring stiffening or rebuilding of the boiler, as HL&P claims would occur with Cedar Bayou 3 if the originally proposed emission limits were adopted. In fact, plant engineers at SCE have estimated that Ormond Beach 2 could withstand an additional three inch w.c. system pressure without any capacity derate. Thus, if Ormond Beach 2 is capable of complying with such stringent emission limits, the staff believes Cedar Bayou 3–which has a lower heat release rate than Ormond Beach 2–is capable of complying with the notably less stringent recommended emission limits without significant derate. Since all of HL&P's utility boilers have lower heat release rates than Cedar Bayou 3 as noted in the above table, except for P. H. Robinson 4 (PHR4) and Cedar Bayou 1 and 2 (which are only slightly higher), HL&P's boilers are also expected to be capable of complying with similar emission limits. The staff also believes more technical research is needed to complete an assessment of the operational impacts associated with NO_x RACT.

HL&P claimed that while the TACB has based the proposed utility boiler emission limits on what has been proposed in the NESCAUM region, the assessment of what percentage of NO_x reductions are achievable, the projected cost, and operational impacts have been based on California's achievements. HL&P indicated that most utility boilers in California were initially designed to burn oil and later converted to burn natural gas; larger furnace volumes and lower NO_x emissions are associated with units designed to fire fuel oil. The staff considered the State and Territorial Air Pollution Program Administrators (STAPPA) and Association of Local Air Pollution Control Officers (ALAPCO) recommended limits as well as the NESCAUM proposal and many pieces of technical, economic, and operational information, including technical reports used to justify the NESCAUM and STAPPA/ALAPCO recommended limits, in developing the proposed rule. The NESCAUM/EPA document titled *Evaluation and Costing of NO_x Controls for Existing Utility Bilers in the NESCAUM Region* (draft June 1992, final December 992 was found to provide the most current comprehensive summary of utility low-No_x retrofit experience nationwide.

The staff relied on the cost estimates from this study in the majority of its estimates. The staff also reviewed technical literature on the subject of NO_x combustion control, reviewed reports summarizing utility low NO_x operational experience, and consulted with NO_x control experts and boiler technology vendors in arriving at viable NO_x emission limits. Based on this review, the recommended 0.20 lb NO_x/MMBtu (30-day average) and 0.26 lb NO_x/MMBtu (24-hour average) emission limits were found to be highly suitable, considering technical and economic practicability, and are considered to represent RACT in Texas. California's newly adopted emission limits are considered too stringent and costly to adopt in Texas, would require the application of controls beyond the level of stringency that is normally considered RACT, and were not realistically considered. However, the past 20 years' experience of California-based utilities in controlling NO_x is so vast that the staff considers the depth and breadth of their technical and operational expertise to be a very practical guide for developing a NO_x control policy for Texas. The staff would be remiss not to consider the abundantly useful information that can be gained from the meaningful NO_x reduction achievements in California. Comparisons with California utility boilers have been invaluable in setting recommended RACT emission limits. HL&P never clearly established that the overall California utility boiler population, which is presently operating at low emission levels, started with lower baseline emissions than units in Texas. Although some units in California were built for oil-firing and were later switched to natural gas, others were built for dual-fuel capability with either gas or oil as the primary fuel, and yet others were originally designed and built for natural gas firing. The staff readily acknowledged that utility companies in Texas historically have relied more heavily on natural gas for electric power generation than companies elsewhere in the country (including California), and that fact is reflected in the design fuel mix of the boiler population of California utility units compared to HL&P's. Yet many additional questions remain about the relative design and performance capabilities of units in these two regions. HL&P never clearly established the fact that relative firebox volumes of natural gas boilers and fuel oil units are actually different, and persuasive comparative data was lacking to support their claims of boiler design uniqueness. Although the staff conceptually agrees that fuel oil firing tends to suggest a need for larger furnace sizes, discussions with boiler design engineers revealed that design fuel is only one of many considerations in sizing a utility boiler furnace, and that a person cannot generalize about furnace size based on fuel type alone Actual firebox volumes of HL&P's units were never contrasted with a comparative California boiler population, so the size differences that exist, if any, have not been clearly established. Furthermore, the differences in NO_x emission levels that are expected from these size differences are not known and were not adequately addressed. Furthermore, some units in California are known to have natural gas as their original design fuel, and others, such as Ormond Beach 2, are known to have high heat release rates. Yet, these units have been complying with notably more stringent emission limits, for about the last two decades, than were originally proposed in §117.105, and doing so without massive operational limitations that HL&P postulated would occur with their units. For example, SCAQMD has had a 125 ppmv (about 0 15 lb NO_x/MMBtu) limit for units larger than 215 MW on a 15-minute average since 1976, San Diego County Air Pollution Control District's limit has been 125 ppmv, averaged hourly, since 1971; Ventura County Air Pollution Control District's limit has been 125 ppmv (for units larger than 2,150 MMBtu/hr heat input), averaged over 24 hours, since 1972. Other California district-wide limits currently in effect include 125 ppmv at Morro Bay, 225 ppmv at Monterey, and 175 ppmv in the Bay Area Currently, new emission limits of 0.25 lb NO_x/MW-hour (about 0.025 lb NO_x/MMBtu) on a 24-hour average, with a 1999 final compliance date and a number of interim limits, have been adopted at SCAQMD. Ventura County has adopted new limits, effective by 1994, of 0.20 lb NO_x/MW-hour (about 0.02 lb NO_x/MMBtu) for units smaller than 215 MW, and 0 10 lb NO_x/MW-hour (about 0.01 lb NO_x/MMBtu) for units larger than 215 MW, similar strict limits are being considered in the San Diego County and Bay Area districts. Gas-fired utility units in these districts have also been complying with their more stringent limits without taking the severely drastic control measures that were claimed would be required for HL&P units. Technology has also advanced beyond the level that was available for these California-based utilities 20 years ago, when they first began to comply with their emission limits, which will make cost-effective NO_x control more feasible now than it was then. The staff admits that NO_x control on these units resulted in certain operational problems, many of which were overcome, but these problems were not of the magnitude that HL&P suggested. The staff found that the effectiveness of various controls, as a percent of NO_x reduction, is generally well established. When control techniques are installed, units with low initial baseline levels generally achieve fewer NO_x reductions than units with higher baseline emission levels. Percent reductions are comparable, if not higher, for units with higher baseline emissions. In establishing emission limits and their associated cost estimates, the staff used HL&P's published baseline emission levels, and applied an estimated reasonable percentage of NO_x reductions to develop supporting information for the proposed §117.105 limits.

HL&P contended that, in assessing costs, the staff did not consider that HL&P units will result in a capacity derate (loss of ability to generate electricity) in order to minimize the operational difficulties associated with NO_x control This derate is a result of FD fan and furnace pressure limitations and can be eliminated by replacing FD fans and upgrading furnace pressure capabilities by rebuilding boilers. HL&P does not think that RACT should include rebuilding boilers. The staff recognizes that operational impacts may result from installing boiler controls. However, operational requirements resulting from operating with lower excess oxygen (O_2) levels and installing FGR, and their impact on HL&P's units, are believed to have been exaggerated. A thorough staff review found no conclusive evidence that operational limitations would necessitate derate on virtually all of HL&P's units, as they have claimed.

For example, HL&P claimed that installation of FGR would require a derate on their units due to pressure capacity limitations of their existing FD fans. However, most utility boilers are designed with excess fan capacity and discharge pressure margins. Excess design margins on FD fans are expected to absorb most of the pressure increases associated with the use of FGR In cases when FD fan upgrades are unavoidable, replacement of a fan at nominal cost might provide the additional pressure and flow needed to overcome FGR operational requirements In a worst-case scenario for their largest unit, fans, motors, controls, and all its associated equipment could be replaced at a cost no greater than $1.8 million, thus avoiding the costly derate they suggested. HL&P also indicated that operating with excess O_2 levels and using 20% FGR, as they claim would be required on virtually all of their gas-fired units to achieve the proposed emission limits, will increase furnace pressures beyond the manufacturers' recommended furnace pressure setpoints and approach the yield strengths of furnace structural members. Although the staff conceptually agrees that furnace pressures would increase under this scenario, the staff believes that increases would be absorbed by excess furnace pressure design margins. HL&P developed a theoretical equation for pressure increase as a function of flowrate that applies to the use of FGR This equation is based on idealized conditions which ignore frictional and dynamic losses, thus exaggerating their expected pressure increases. The staff also reviewed HL&P test data which show the effect of FGR on FD fan, windbox, and furnace pressures. The data indicates that pressure increases are far less than are predicted by HL&P's theoretical equations, which they used as a basis for estimating the amount of required derate, this is shown in the following table

Effect of FGR on the fan, furnace, and windbox pressure:

FGR Rate (%)	Increase in Fan operating pressure (%)		Increase in windbox pressure (%)		Increase in Furnace pressure (%)	
	Test data	HL & P's Equat.	Test Data	HL & P's Equat.	Test Data	HL & P's - Equat.
11.3	2%	23.8%	0.0%	23.8%	0.0%	23.8%
13.0	4%	27.7%	0.0%	27.7%	0.0%	27.7%
19.7	12.7%	39.0%	11.4%	39.0%	13.3%	39.0%
20.0	18%	44.0%	20%	44.0%	24%	44.0%

The staff did not find any conclusive evidence that massive derates will be needed and does not believe that rebuilding boilers would be required. For example, SCE's Ormond Beach 2 has the same furnace volume and a slightly higher heat release rate than HL&P's Cedar Bayou 3, as discussed in the staff's response to HL&P's comment concerning physical limitations. This unit is currently complying with a 125 ppmv (0.15 lb NO_x/MMBtu) limit on a 24-hour rolling average basis, with plans to comply with 0.10 lb NO_x/MW-hour beginning later in 1993. Ormond Beach 2 did not require and is not expected to require boiler rebuilding in spite of the extremely stringent emission limits imposed. Boiler furnace structural reinforcement, which usually involves the replacement of buck stays and other structural supports, might be technically and economically achievable, and carry costs that are within the range associated with RACT. To imply that this involves "rebuilding boilers" as they have done, is an exaggeration.

HL&P claimed that the staff did not consider the effect of variability of emissions when estimating capital costs. The staff initially had no data to show the emission variability of HL&P's boilers. In later meetings, HL&P provided TACB with CEMS data on two of their largest units, Cedar Bayou 1 and 2. Statistical analysis was applied to the data, and variability of 29% from the mean was found on a 24-hour average basis. The variability of emissions on these two units was used to represent the variability of emissions on all of their units. This data was considered in arriving at new recommended emission limits.

HL&P observed that the proposed emission limits are based on a one-hour block average mass limit and a 24-hour rolling average lb NO_x/MMBtu limit. HL&P stated that the proposed averaging periods, coupled with lower numerical emission limits, are too stringent when compared with EPA's recommendations, which are based on a 30-day rolling average. GHP and GSU suggested a 30-day average; HL&P recommended that if the proposed emission limits are to be adjusted to account for their units' variability, the new proposed limit should be 0.26 lb NO_x/MMBtu for both walland tangential gas-fired boilers on a 24-hour rolling average, and 0.20 lb NO_x/MMBtu based on a 30-day rolling average, both calculated at the maximum heat input for all units either on a unit-specific basis or as an assigned value derived from the system-wide average; with no one-hour mass limitation. This closely approximates EPA's RACT recommendation when applied to HL&P's boiler population, with an associated capital cost totaling $200 million. As a result of negotiations with HL&P, the staff has deleted the hourly emission limit, changed the 24-hour emission limit recommendation from 0.20 lb NO_x/MMBtu to 0.26 lb NO_x/MMBtu, and established a proposed 30-day emission limit of 0.20 lb NO_x/MMBtu. Averaging times were taken into account by the staff in setting the higher 24-hour limit. These limits evolved from negotiations between HL&P and TACB staff, and are proposed as a compromise in order to facilitate rulemaking progress. The staff's highest estimate of capital costs for compliance is about $75 million, based on the extensive use of LNB as a control approach. This is in contrast with HL&P's estimate of $200 million.

HL&P claimed that variability in NO_x emissions is documented to be 29% for HL&P units based on a 24-hour average, and that it will have to operate at significantly lower emission rates than the proposed 0.20 lb NO_x/MMBtu emission limit to be able to account for variability. HL&P may not necessarily need to operate at emission rates that are significantly lower than the rule limits in order to comply. If HL&P reduces a unit's emissions variability, it could operate it at correspondingly higher emission rates, closer to the emission limit.

HL&P stated that its analysis shows that 60% of the NO_x reductions required by the proposed rule may be achieved for only 9.0% of the total cost, and 74% of the reductions may be achieved for 20% of the cost. It feels that a 74% reduction would represent RACT; for its system this approximates EPA's recommended emission limits. The staff conceptually agrees with this comment. This information was presented late in the negotiation process, leaving inadequate time to thoroughly evaluate it. It should be noted, however, that these numbers were deduced from HL&P's cost estimates of compliance with the proposed rule, which the staff believes are too high.

HL&P said that the proposed emission limit of 0.38 lb NO_x/MMBtu for coal-fired utility boilers, calculated on a 24-hour rolling average basis, is too stringent, does not constitute RACT, fails to distinguish between wall and tangential-fired boilers, and is inconsistent with EPA and NESCAUM guidance. NESCAUM's recommended limits are 0.38 lb NO_x/MMBtu for tangential-fired boilers and 0.43 lb NO_x/MMBtu for wall-fired boilers, 24-hour average and EPA's respective recommended limits are 0.45 lb NO_x/MMBtu and 0.50 lb NO_x/MMBtu, 30-day rolling average. HL&P's suggested emission limits are 0.38 lb NO_x/MMBtu for tangential-fired and 0.43 lb NO_x/MMBtu for wall-fired coal utility boilers, based on a 24-hour rolling average; with no one-hour mass emission limit. There are only four coal-fired electric utility boilers in the four ozone nonattainment areas in Texas, and these units are located at HL&P's W. A. Parish generating station. Due to their large size and economical fuel, the four units are among the eight highest NO_x emitting units in the ozone nonattainment areas. These units were built in the 1970's in accordance with the NO_x limits of NSPS, Subparts D or Da. The emission rates actually achieved by the units are substantially lower than their currently applicable 0.70 lb NO_x/MMBtu, three-hour average (Subpart D) or 0. 50 lb NO_x/MMBtu, 30-day rolling average (Subpart Da) emission limits.

Throughout the rulemaking process, the level of NO_x emission controls currently applied to the coal-fired units has been considered by the staff to represent RACT. The staff's intent has been to establish RACT limits for these units equivalent to their actual emission rates, over an appropriate averaging period. The advantage of doing this is that substantial paper reductions in emissions may help with the attainment modeling demonstration, which must be made using potential emissions. Negotiations with HL&P resulted in recommended emission limits for coal-fired boilers of 0.38 lb NO_x/MMBtu for tangentiallyfired utility boilers and 0.43 lb NO_x/MMBtu for wall-fired boilers calculated on a 24-hour rolling average. The recommended change reflects the change between the NESCAUM limits as originally proposed and as eventually adopted by NESCAUM. The staff agrees that the emission limits acceptable to HL&P represent RACT. The staff has segregated the four coal-fired units from the rest of the system average to ensure that the emission reductions sought for the gas-fired units are not affected by the emission limits for the coal-fired units. Since the coal units are among HL&P's low-cost electricity producers, these units have the highest annual capacity factors of the affected units. By segregating the coal-fired and gas-fired units in the system averaging of §117.107, the system averaging is more likely to achieve reductions equivalent to reductions achievable under §117.105. HL&P stated that industrial boilers currently operating under NSPS, 40 Code of Federal Regulations (CFR) 60, are not subject to the proposed rule. Similar language should be included in the utility section of the rule.

HL&P stated that industrial boilers currently operating under NSPS, 40 CFR 60, are not subject to the proposed rule. Similar language should be included in the utility section of the rule. The staff agrees that consistency should exist between provisions for industrial and utility boilers. The staff has added similar language to that for industrial boilers subject to 40 CFR 60 in §117.105 for utility auxiliary boilers. However, industrial units subject to NSPS are not entirely exempt from the proposed rule, nor will utility auxiliary units. These units, though retaining their NSPS emission limits in lieu of other proposed emission specifications, are to be subject to all other provisions of the rule In order to achieve the quantity of emission reductions necessary for ozone reduction, the staff does not recommend applying the NSPS emission limits to electric generating units

HL&P recommended language to adopt these emission limits "either by unit-specific limitation or system-wide averaging technique" Section 117.107 addresses system-wide averaging, so specifying that the emission limits are "either by unit-specific limitation or system-wide averaging technique" in §117.105 is not necessary.

HL&P indicated that the word "only" should be deleted from §117.105(b) because coal units may co-fire very small quantities of natural gas or oil for flame stability purposes. The word "only" has been deleted from §117.105(b), since coal-fired units sometimes fire limited quantities of natural gas

HL&P indicated that proposed emission specifications for oilfired utility boilers are 0 10 lbs NO_x/MMBtu higher than the specifications for gas-fired utility boilers and recommended an emission limit of 0.36 lbs NO_x/MMBtu for oil-fired boilers, based on a 24-hour rolling average. The staff believes that the §117.105 emission limit for oil-fired utility boilers, 0.30 lbs NO_x/MMBtu on a rolling 24-hour average basis, is appropriate. Several of HL&P's boilers have been converted and issued TACB permits to enable continuous fuel oil firing A review of its permit files has shown that representations were made that they were capable of operating at 0. 30 lb/MMBtu, and capable of meeting NSPS emission limits of 0.30 lbs NO_x/MMBtu on a threehour rolling average basis, in accordance with 40 CFR 60, Subpart D. Discussions with HL&P have revealed that additional information may become available which demonstrates that permit limits higher than 0.30 lb NO_x/MMBtu were applied to these units, but permit information on these units has convinced the staff that the recommended 0.30 lb NO_x/MMBtu limits are technically achievable and economically reasonable. Since similar units may already be achieving 0.30 lbs NO_x/MMBtu emission levels on a shorter averaging period, the staff believes that the proposed limit is representative of RACT and appropriate for the entire population of fuel oil capable boilers.

HL&P suggested that §117.105(d) be revised to remove heat input weighted average emission specifications for coal-fired units firing a mixture of fuels, change the 24-hour average emission limits, and allow for 30-day average emission limits to be based on gas or gas/waste oil firing only. The staff conceptually agrees with the first part of this comment. Coal-fired boilers may co-fire limited quantities of natural gas, as much as 3.0%, for flame stability purposes. These limited quantities of natural gas are not expected to significantly affect the emission rates of coal-fired boilers, so the heat input weighted average shall apply to units burning natural gas and fuel oil only. The language of §117.105(d) has been revised to reflect this flexibility and to contain the newly proposed 24-hour average emission limits for natural gas firing. The staff agrees that emission limits should be calculated based on 100% natural gas firing, but this section will not include provisions for heat input weighted average, 30-day emission limits.

HL&P recommended deleting §117.105(e). The rule should not contain a block one-hour average emission limit. The staff agrees with this comment and this section has been deleted.

HL&P suggested raising the emission limit in §117.105(f) for utility gas turbines firing natural gas from 25 to 42 ppmv, to be consistent with the limit for industrial gas turbines in §117.205(a)(4)(b), relating to Emission Specifications (industrial sources). For purposes of maintaining rule consistency between the electric utility and industrial sections, the staff has revised the emission limit as suggested. HL&P is the only affected electric utility with gas turbines, some of which could be subject to the emission limit of §117.105(f). None of these units are currently operating at output levels in MW-hours that would subject them to this limit. However, the eight Frame 7B gas turbines at HL&P's Wharton Station have recently received a construction permit for turbine upgrade to Frame 7E configuration. The modification will increase the turbines' efficiency and power output in addition to reducing NO_x emissions. The efficiency increase is expected to result in operation at output levels in MW-hours equal to or greater than the output level referenced in §117.105(f). This turbine upgrade is permitted at a BACT limit of 25 ppmv NO_x. Consistent with longstanding EPA policy, any unit which has a BACT-based emission limit which is more stringent than its RACT limit must use the BACT limit in computing the plant-wide allowable emission rate. To do otherwise would allow "double counting" of the emission reductions under both the new source review and RACT regulations.

HL&P recommended deletion of the 65 ppmv limit for utility gas turbines firing fuel oil in §117.105(g), since no limit is imposed on comparable industrial gas turbines. The staff is unaware of any industrial gas turbines in the two nonattainment areas affected by this proposed rule which have fuel oil firing capability. The staff may consider a proposed 65 ppmv limit for industrial gas turbines for the sake of rule consistency, and recommends that this be considered in future rulemaking.

HL&P indicated that under the Wisconsin Electric Power Company (WEPCO) ruling, most CO emissions that result from the installation of NO_x controls will not be considered major modifications by EPA when sources are implementing the 1990 FCAA Amendments. HL&P requested that the CO emission limitation of 400 ppmv be deleted. GSU contended that a CO emission limit should not be included. The staff's intent in proposing a CO emission limit is to ensure that retrofit NO_x controls, which have the potential to cause a CO emissions increase, will not result in excessive CO emission levels. CO is a product of incomplete combustion, is a criteria pollutant, and is also known to play a limited role in ozone formation. As an organic compound, CO has a lower ozone formation potential than methane or ethane, but is nonetheless an emission input in the UAM due to the large quantity of actual emissions, primarily from mobile sources. VOC emissions are also products of incomplete combustion, and may concurrently increase with CO increases. Any VOC increases associated with higher CO emissions are of concern to the staff because of their potential to exacerbate ozone formation. HL&P stated in its comments that some site-specific increases in CO emissions should be expected with stringent NO_x RACT reductions. However, *Evaluation and Costing of NO_x Controls for Existing Utility Boilers in the NESCAUM Region* concluded that, except for units with extremely low NO_x levels such as California's, "significant NO_x reductions are possible from gas-fired boilers without an increase in CO emissions" (pages 7-15). This study documented CO emissions that are associated with NO_x control levels that are, in the majority of cases analyzed, significantly more stringent than the TACB staff is currently using under §117.105. CO emissions for the gas-fired boilers studied showed a range of 12 to 90 ppm at NO_x emission levels in the range of 0.06 lb NO_x/MMBtu to 0.31 lb NO_x/MMBtu. In cases where combustion controls increased CO levels above their regulatory limits, plant operators were able to make subsequent reductions to CO emissions by increasing excess combustion air. These boilers are being controlled with combustion modifications to more stringent NO_x levels than the TACB staff is currently setting, and their CO limits are no higher than 200 ppmv. This is less than half the TACB staff's recommended CO level, yet stringently controlled boilers are capable of operating in compliance with this regulatory limit. The staff concludes that the proposed limit is much higher than a properly adjusted utility boiler will produce. The proposed 400 ppmv CO emission limit was developed as an industrial boiler limit. The staff extended the limit to utility boilers for the sake of treating these sources equably. In any case, the proposed limit creates an upper bound on CO, which could potentially exceed 400 ppmv. The staff has retained the CO limit.

GSU recommended that the CO emission limit not be corrected for O_2.

The staff overlooked inclusion of a reference to 3.0% O_2, which is a conventional diluent correction for a boiler concentration limit. After reviewing this issue with GSU, the staff agrees that the CO emission limit for their utility boilers should not be corrected for O_2. The rule language as proposed does not correct CO limits for O_2, so the staff recommends retaining the existing language.

HL&P indicated that the proposed rule is based upon the application of combustion controls and not the use of selective catalytic reduction (SCR) or selective non-catalytic reductions (SNCR), so the ammonia slip-emission limitation of 10 ppmv in §117.105(k) should be deleted. GSU agreed that an ammonia emission limit should not be included. In the event that some industries and/or utilities may elect to install SCR or SNCR technologies, an ammonia emission limit is necessary to prevent excess ammonia slip. The use of SCR and/or SNCR is a plausible scenario for a utility electing to overcontrol a large, high capacity factor boiler to offset emissions from other units. If SCR or SNCR technologies are not chosen, the ammonia emission limit will have no effect on other means of control. However, a higher, 20 ppmv emission limit based on a one-hour averaging time period has been added.

Section 117.107-Alternative System-Wide Emission Specification. HL&P indicated that under §117.107, industrial sources can use post-1990 shutdowns in their calculations of plant-wide emission specifications but utilities cannot; they would like similar language included for utilities. EPA will not allow the use of plant shutdowns in determining plant-wide emission limits. Shutdown credits have been deleted for industrial sources and cannot be extended to utility sources.

HL&P and EPA suggested that the reference to "plant-wide" in section 117. 107(b) should be changed to "system-wide." The proposed rule at §117.107(b) contained an erroneous reference to "plant-wide" emission limits. The wording has been changed to refer to "system-wide" emission limits.

HL&P suggested that §117.107(c) clearly specify that systemwide averaging be allowed among gas turbines and auxiliary boilers, even though they cannot be included in the utility boiler system-wide average. The staff has concerns with RACT equivalency when individual unit emission rate limits are applied on a plant-wide or system-wide basis. Under any emissions averaging based on maximum rated capacity, there is the possibility that actual emissions may be higher than if each unit had complied with RACT emission limits on an individual basis. The problem with allowing system-wide averaging among units of a given class, such as utility-peaking gas turbines or auxiliary boilers, is that these units have highly variable annual capacity factors. Data supplied by HL&P indicate that one-third of their gas turbines operate under 100 hours per year, with only a few operating over 2,000 hours per year. Information supplied by HL&P

concerning its auxiliary boilers shows similar variations in annual capacity utilization. If HL&P installs controls on units which are used proportionately less than other units with higher capacity factors, on which it installs less controls, the resulting emissions reductions are not equivalent to RACT. EPA has expressed concern, and will require states to demonstrate, that any emissions reductions from an averaging rule achieve actual reductions equivalent to traditional RACT methods based on individual unit limits. The language excluding utility-peaking gas turbines and auxiliary boilers from system-wide averaging has been retained.

HL&P commented that the one-hour mass emission rate standard of §117. 107(d) is not appropriate. The staff agrees and the onehour mass emission rate standard has been deleted.

GSU commented that the rule should clarify that for utilities, plant-wide averaging within a single ozone nonattainment area is available as an alternative to system-wide averaging. GSU would not be allowed to use system-wide averaging under the proposed rule because it operates generating units in both the Beaumont/Port Arthur and Houston/Galveston ozone nonattainment areas. The intent of the rule is to allow system-wide averaging only within a given ozone nonattainment area. Since GSU has only one operating plant in each ozone nonattainment area, the "system" for emissions averaging purposes is the one plant. Thus, GSU operates two independent "systems."

GHASP objected to allowing system-wide emission limitations. GHASP recommended retaining an earlier rule provision whereby a unit found in violation of an emission specification meant that all units within a system-wide average would also be in violation. System-wide averaging is a compliance method that allows for greater flexibility and cost-effectiveness while achieving emission reductions similar to those for a rule with individual, unit-specific emission limits. System-wide averaging provisions must meet certain RACT equivalency criteria, which call for reductions achieved under system-wide averaging to be equivalent to reductions obtainable by unit-specific emission limits, to be approved by EPA. Several system-wide averaging alternatives that have been suggested by industry are not currently recommended by the staff due to potential EPA disapproval because of RACT equivalency problems. The current system-wide averaging provisions have been retained, except to limit the averaging to like categories of equipment to improve the chances of obtaining RACT equivalency. An earlier draft proposal of this rule included a provision for all units in a system-wide average to be in violation of the emission specifications if one unit was found to be in violation. This was because the system-wide averaging methodology then under consideration specified only one enforceable emission limit for an entire system, such that all units in a system-wide average could be operated at any emission rate provided that their aggregate emissions did not exceed their applicable system-wide limit. This was a facility cap proposal, which the utilities rejected due to concerns about technical difficulty in maintaining the data from all sources on a continuous basis. Due in part to this potential enforceability issue, the proposed §117.107 now allows only system-wide averaging, which requires enforceable unit-specific limits to be established and reported in an owner's final control plan. These new unitspecific limits allow for enforcement actions to be taken for individual units, instead of for an entire utility system, as under the earlier draft Rule language will not be added to make each unit in violation whenever one unit is in violation.

EPA recommended referring to the §117.105(g) emission specification in the definition of "NO_x (allowable)." Section 117.107(d)(2) has been revised accordingly.

EPA supported system-wide emission averaging, but must be assured that RACT equivalent reductions would be achieved. EPA stated that the use of maximum rated capacities rather than actual heat inputs in calculating system-wide emission limits does not meet their criteria, but would be acceptable if any one of the following were met: factors are consistent with the State attainment demonstration; sources using system-wide emission limits are required to show that system-wide emission rates based on actual heat inputs over a 30-day period do not exceed system-wide emission limits; and TACB justifies that emission limits combined with averaging provisions constitute RACT.

The averaging allowed under §117.207(a)-(h) is equivalent to RACT. Equivalency is demonstrated by the application of RACT emission limits to each affected source and using preference testing and emissions monitoring to verify compliance. Section §117.207(i) has been deleted at the request of EPA to ensure equivalency.

Since TACB was trying to write an NO_x RACT rule in the specified timeframe mandated by Congress in the 1990 FCAA Amendments, and EPA guidance was not available on the use of maximum rated capacities at this time, the staff believes that the emission limits combined with the averaging provisions constitute RACT for the affected sources.

Section 117.109–Initial Control Plan Procedures. HL&P and B&B suggested that §117.109 clarify that initial control plans are intended for planning purposes only and are not subject to enforcement. B&B also suggested deleting the requirement to make initial control plans subject to TACB approval, except when the information provides specific dates for compliance extensions beyond May 31, 1995. The staff agrees with the concept that if a person meets the requirements which are due by May 31, 1995, the question of how the person got there is not an issue. The FCAA Amendments require that RACT measures be implemented as expeditiously as is practicable, but no later than May 31, 1995. The staff recognizes that the installation of control equipment by May 31, 1995 is difficult enough that the TACB should not propose, by rulemaking, specific dates prior to May 31, 1995, as a means of ensuring that control equipment is implemented as expeditiously as is practicable. However, the staff recommends that the rule continue to contain control plan design requirements, which are due by April 1, 1994. The wording of §117.109 has been revised to reflect that the Executive Director shall approve the initial compliance plan if it contains all the information specified in §117. 109. As discussed in §117 540(a), wording has been deleted in that section which prohibits deviation from the initial compliance plan, except as provided in that section. Section 117.109 has been clarified so that any revision (i.e., deviation) to the initial compliance plan is to be submitted with the final control plan.

The staff believes that these changes address the commenter's concern regarding prohibition of deviation from the initial compliance plan.

HL&P indicated that the requirement contained in §117.109(c)(1) to submit the anticipated annual heat input for each unit should be deleted. Annual heat inputs must be known in order to determine a unit's potential for exemption. Annual heat inputs are needed to evaluate control plans in order to assess the need for future RACT equivalency demonstrations.

The staff sees benefits of requiring both the maximum rated capacity and the anticipated annual heat input of the affected industrial boilers and heaters. The anticipated annual heat input data is generally available, can readily be included in the initial control plan, and it is a number which will be required in setting a facility cap, which is an option to be considered for future rulemaking The requirement of listing the anticipated annual heat input of each unit has been revised to require the listing of the anticipated annual capacity factor of each unit in the proposed rule The annual capacity factor provides the same information as the anticipated annual heat input, except that it is expressed as a percentage.

HL&P indicated that the reference to mass emission rate in §117.109(c)(4) should be deleted. The staff agrees with this comment and the reference to mass emission rates has been removed, since mass emission limits are no longer recommended Instead, reference to emission rates in lb NO_x/MMBtu on a 24-hour and 30-day average basis has been included in §117.109(c)(4)

HL&P commented that the proposed rule specifies minimal control plan requirements for industrial sources, but that utilities must submit very extensive control plans Section 117.109(c)(6) and (7) should be deleted The staff agrees and §117.109(c)(6) and (7) have been deleted. Rule language concerning control plan requirements for utility sources will be revised to be consistent with the requirements for industrial sources.

B&B suggested that §117.109 provide for making requests for a later final compliance date in initial control plans. The staff agrees that persons seeking final compliance dates subsequent to May 31, 1995 should submit these requests with the initial control plans. However, in §117.540 the required elements of a request for an extension of the final compliance date has been maintained.

EPA suggested that initial control plans should include the system-wide emission limit or an assignment of anticipated NO_x emission rate for each affected unit. The intent of §117.109(7) is to require the basis for the calculations, which should include the system-wide emission calculations and the preliminary assignment of the individual emission rates for the affected units. The staff believes that this explanation will document the intention of the rule language.

Section 117.111-Initial Demonstration of Compliance. HL&P observed that §117.111 does not specify performance testing requirements for industrial sources, but utilities are required to test at four points over "normal" operating loads. CEMS data from utility boilers, based on the first 30 operating days after the deadline, should be allowed in lieu of testing. For gas turbines with CEMS, one-hour monitoring data should similarly be allowed to demonstrate initial compliance.

The wording of this subsection has been revised to remove the reference to "normal operating load" and to make the testing requirements consistent with the requirements for industrial sources. The staff disagrees with HL&P's suggestion to make initial demonstration of compliance based on operating data collected after the final compliance deadline, but it will be based on CEMS data.

HL&P commented that the language of §117 111(b) should be modified to eliminate the requirements to demonstrate compliance with a mass limitation. The requirement to demonstrate compliance with a mass limitation has been deleted, since mass emission limits are no longer recommended under §117.105. Demonstrations of compliance with the 24-hour average and 30-day average lb NO_x/MMBtu emission limits will be based on CEMS data.

GSU indicated that continuous, in-stack CO emission monitors should not be required; instead, alternative means of demonstrating compliance with the CO limit, such as periodic stack testing or alternative monitoring methods, should be allowed. The staff believes that periodic stack testing or alternative monitoring methods are not as effective as continuous monitoring for demonstrating compliance with applicable CO limits and does not recommend changing this requirement.

GSU commented that if CO monitors are required, CO monitor specifications should reflect the requirements of 40 CFR 60 rather than 40 CFR 75. The staff agrees that 40 CFR 75 does not require CO monitoring and that the appropriate specifications for continuous CO monitoring are contained in 40 CFR 60. However, administrative requirements do not allow the addition of CO monitor specifications to the adopted rule language, since it was not contained in the original proposal, so it will be reconsidered in subsequent rulemaking.

GHASP recommends removing the phrase "as near thereto as practicable" from §117.111(a). The compliance averaging time has been extended to 24-hour and 30-day periods. Under these long-term averages, holding a utility boiler to maximum rated capacity for testing purposes is impractical. Therefore, the staff has deleted the entire reference to "maximum rated capacity" in §117. 111(a).

GSU commented that the rule should indicate which 40 CFR 60, Appendix A, test methods are necessary for demonstration of initial compliance, and should allow for minor modifications to these test methods, if necessary. GSU recommended making §117.111 consistent with §117.211(f) and allowing for alternative test methods subject to Executive Director approval. Administrative requirements do not allow revision of the rule language to specify additional test methods without formally re-proposing the rule, since they were not included in the original proposal. However, since monitoring using CEMS was already required, the staff agrees with GSU and recommends that initial demonstration of the NO_x emission limits on a 24-hour and 30-day average be similar to the requirements of 40 CFR 60.46a(e), which addresses CEMS operation. Specification of test methods for initial demonstration of the CO limits cannot be added, but will be proposed in later rulemaking. The language in §117.111 has been revised to make it consistent with §117.211(f), and to allow for alternative methods subject to Executive Director approval.

Section 117 113-Continuous Demonstration of Compliance. GHASP recommended retaining in §117.113 the provision, that was in an earlier rule draft, whereby continuous emission data collection was required during periods of CEMS downtime. GHASP also recommended retaining a requirement to report CEMS data to TACB regional offices by a telecommunications link that was contained in the earlier draft. Requiring continuous data collection during periods of CEMS downtime would most likely require installation of redundant monitors. In order to avoid imposing redundant monitoring requirements and improve cost-effectiveness, monitoring requirements are made consistent with EPA's Title IV rules promulgated under 40 CFR 75. This will allow resources to be allocated for the purchase of equipment that will actually produce NO_x reductions, instead of for monitoring equipment. TACB currently lacks the staffing to be able to perform a viable review of the quantity of data that would be reported by a telecommunications link. Therefore, continuous data collection during periods of CEMS downtime and a telecommunications link are not needed.

HL&P suggested that the requirements to monitor CO and exhaust or fuel flow rate be deleted from §117.113(a) for consistency with the monitoring provisions of 40 CFR 75. Although not required by 40 CFR 75, CO should be tested and monitored in accordance with 40 CFR 60 to ensure initial and continuous compliance with CO emission limitations of §117.105(j). Exhaust or fuel flowrates must be monitored in order to compute the mass emission rate (in lb/hr or tons per year) for future demonstrations of NO_x RACT equivalency for emissions inventory data collection purposes.

HL&P commented that in §117.113(a), utility gas turbines with an annual electric output less than the product of 2,500 hours and the MW rating of the unit should be exempted from CEMS/parametric modeling requirements. HL&P also recommended in §117.113(a) to allow the option of reporting steam-to-fuel or water-to-fuel ratios implied by §117.119(d), relating to Notification, Recordkeeping, and Reporting Requirements, but not referenced in that section. Enhanced monitoring methods will need to be developed for each emission unit which is a major source of NO_x emissions. Section §117.213(e) in the industrial section of the rule specifies that monitored steam-to-fuel or water-to-fuel ratios may be used to demonstrate compliance with the applicable emission limit. For electric utility turbines which are subject to §117. 105(h) or (i), relating to Emission Specifications, and use steam or water injection for NO_x compliance, the staff has added the corresponding industrial gas turbine rule to §117.113 for utility gas turbines, for the sake of rule consistency, in later rulemaking.

HL&P indicated that the wording in §117.113(a) could be interpreted inconsistently with the provisions of 40 CFR 75, Appendix E. The use of EPA's phrase "peaking units" creates the potential for confusion with the term "peaking gas turbine or engine" defined in §117.10. The staff agrees and has revised §117 113(a) to prevent possible confusion.

HL&P suggested that §117.113(a) implies that CEMS are required on all utility stationary gas turbines, since those units are affected units under §117.101, and requested that this be corrected in the final rule. HL&P also requested that stationary gas turbines exempt from emission specifications be exempt from monitoring requirements. The staff intended, but did not include in the original rule proposal, provisions allowing peaking gas turbines to monitor steam-to-fuel or water-to-fuel ratios as an alternative to CEMS. The staff has extended the option for operating parameter monitoring systems, comparable to the industrial rule for gas turbines at §117.213(e), to utility gas turbines rated less than 30 MW or peaking gas turbines which use steam or water injection, in lieu of installing CEMS in accordance with 40 CFR 75.

The rule identifies that gas turbines exempt from emission specifications are also exempt from monitoring requirements. Section 117.103 states that certain stationary gas turbines are "exempted from the provisions of this undesignated head." Therefore, the rule does not require CEMS for all stationary gas turbines. Stationary gas turbines exempt from emission specifications are exempt from monitoring or parametric modeling requirements, and stationary gas turbines subject to emission specifications are intended to have applicable CEMS requirements.

HL&P indicated that gas turbines subject to the emission specifications of §117.105(h) and (i) should be exempt from all continuous emission monitoring/parametric modeling requirements. The staff disagrees, since without continuous monitoring or parametric modeling, emission rates for these units will be impossible to quantify. Establishing emission rates for major sources is one of the basic intentions of the proposed rule.

HL&P indicated that §117.119(d) should be clarified to allow reporting of water-to-fuel ratios to demonstrate compliance. The staff agrees and has revised §117.119(d) to allow reporting of water-to-fuel ratios.

HL&P commented that §117.113(c) should provide that the use of 40 CFR 75, Appendix E, is an option, not a requirement, in the event that a utility may prefer to utilize CEMS in lieu of Appendix E. The staff agrees and has changed §117.113(c) rule language to allow continuous emissions monitoring of peaking turbines, in lieu of monitoring in accordance with 40 CFR 75, Appendix E.

HL&P noted that §117.113(d) requires auxiliary boilers to install CEMS in accordance with 40 CFR 75 or §117.213, or to use parametric modeling procedures. HL&P recommended an exemption for auxiliary boilers with heat input less that 8.76 by 10^{11} Btu/year from monitoring/parametric modeling requirements. Auxiliary boilers with an annual heat input greater than 2.2 by 10^{11} Btu/year generally have the potential to emit significant quantities of NO_x per year and are subject to emission limits and other provisions of the rule. They must be monitored to be subject to emissions verification and enforcement, so monitoring or parametric modeling provisions of the rule must apply. Exempting units with as much as 8. 76 by 10^{11} Btu/year would exempt most auxiliary utility boilers from monitoring requirements and the accompanying verification and enforceability, as well.

GSU recommended allowing alternative locations for in-stack monitoring subject to approval of the TACB Executive Director. The staff agrees to allow alternative locations to in-stack monitoring subject to the approval of the Executive Director, and §117.113 has been revised accordingly.

Section 117.115-Final Control Plan Procedures. HL&P indicated that the initial demonstration of compliance in §117.510(4) should be based on CEMS data for the first 30 operating days after the final date of compliance, and results submitted after allowing time for the CEMS data to be processed. Section 117.115(a) should require that the final control report be submitted within 180 days after, instead of before, the final date for compliance. This is consistent with 40 CFR 60.8. Section 117.115(a) currently requires submittal of 30-day operating results of the initial compliance demonstration before they occur. Section 117.115(b) should allow the submission of the results after the final date of compliance. The intent of setting a final compliance date is to have the required controls in place, operational, properly monitored, and tested by that time However, the staff recognizes the potential difficulty in obtaining 30 days' operating data for the initial compliance demonstration by May 31, 1995.

NSPS Subpart A, §60.8 allows testing and submission of results up to 180 days after initial start-up of a new facility. The complexity of applying NO_x controls does not compare to the complexity of starting up a new utility electric generating unit, so the staff does not believe that it is appropriate to allow 180 days after the final compliance date to submit the final control report. To assist in meeting the requirements of the initial compliance demonstration, the staff has changed §117.510 to allow the submission of test results to demonstrate compliance any time up 60 days after the final compliance date. Submittal of the final control report 180 days after the final compliance date would, in effect, defer final compliance by almost six months. Since §117.540 already provides for phased implementation of RACT to account for potential technical and scheduling problems, allowing further deferral of the final compliance date is not desirable. The initial demonstration of compliance and subsequent report will be required 60 days after the final compliance date in §117.510.

HL&P suggested that the one-hour emission limitation should be deleted from §117.115(b)(1). The staff has already agreed with HL&P to remove the proposed one-hour emission limitation requirement from the rule, and instead require a 30-day emission limit and a 24-hour emission limitation with an appropriately higher lb NO_x/MMBtu limit. Section 117.115(b)(1) has been revised accordingly.

EPA requested clarification of the process for approval of maximum allowable NO_x emission rates, submitted in final control plans. Enforceable maximum allowable emission rates will be assigned to each unit complying with the system-wide averaging provisions of §117.107. The approval process will consist of verification that maximum allowable NO_x emission rates will achieve expected reductions, comply with system-wide emission limitations, and otherwise comply with the rule provisions.

HL&P commented that §117.117 should be clarified to allow owners or operators to submit revisions to their final control plan, and should state that a permit or permit amendment will be unaffected if NO_x emission rates are being merely reassigned while still meeting system-wide average emission limitations. The revision of a control plan should only constitute a permit revision for a permitted unit. The last sentence of this section is unnecessary. The language of §117.117 allows owners/operators to submit revisions to final control plans if revisions to plan contents are desired. The staff plans to propose additional rulemaking at §117.550 to make permitting requirements less burdensome to industry. The last sentence of this section was included to clarify that new units are not to be used toward achieving rule compliance. However, since the definition of "unit" at §117. 10 excludes units placed into service after November 15, 1992, this sentence is unnecessary and the staff deleted it. In addition, the title of the section has been modified by the staff from "Revision of Control Plan" to "Revision of Final Control Plan," to better represent the contents of the rule.

Section 117.119-Notification, Recordkeeping, and Reporting Requirements. HL&P commented that §117.119(a), which requires very burdensome recordkeeping, should be deleted and existing rules for major upsets and maintenance should apply. Section 117.119(a) has been revised to make it consistent with the requirements of the industrial rule and less burdensome to utilities. Recordkeeping and reporting is required that is specific to this particular rule, so existing General Rule provisions regarding major upsets and maintenance should not be applied. See the response at §117.219 to comments of Chevron regarding recordkeeping.

HL&P commented that §117.119(b) should be clarified to state that it only applies to "affected units subject to the emission specification of §117.105. " The staff agrees and has revised the rule to state that §117.119(b) is applicable only to units subject to emission specifications of §117.105 or §117.107.

HL&P commented that §117.119(c) should be deleted since it redundantly requires submittal of performance testing data covered under §117.111 and §117.115. Although the identification of reporting requirements for testing conducted under §117.111 or CEMS performance evaluations conducted under §117.113 is redundant, it has been repeated here for clarity.

HL&P indicated that the phrase "process operating time" should be deleted from §117.119(d)(1) since its intent is unclear and it does not appear to be relevant. The staff has revised §117.119(d)(1) to change "process operating time," which came from NSPS, 40 CFR 60.7, to read "unit operating time."

HL&P commented that the language of §117.119(d)(5) should be clarified so that the CEMS operating time is a function of unit operating time. A facility should not be penalized for taking a CEMS out of service during a unit outage to perform instrument maintenance. For reporting purposes, CEMS downtime is already expressed as a function of "total operating time;" therefore, a facility is not being penalized for taking a CEMS out of service during an outage to perform instrument maintenance. The staff has revised §117.119(d) (5) to refer to "total unit operating time" for clarity.

HL&P commented that §117.119(e) should clarify that only hourly operating data is required. Hourly data during off-line periods is not required. The staff agrees and has revised §117.119(e) to not require hourly data during off-line periods and make it consistent with the requirements for industrial sources.

HL&P requested that the reference to "pounds per hour (block one-hour average)" in §117.119(e)(1) be deleted. HL&P suggested noting that these recordkeeping requirements are only applicable to utility boilers and not gas turbines, since gas turbines are subject to different averaging periods. HL&P suggested that hourly reporting of the fuel burned be deleted from §117. 119(e)(3) and that §117.119(e)(6) also be deleted. HL&P suggested that §117.119 creates duplicate recordkeeping and reporting requirements that are already subject to the NSPS requirements per 40 CFR 60, Subpart Db; only the NSPS recordkeeping and reporting requirements should be required for these units. The staff agrees that the reference to pound-per-hour emissions in §117.119(e)(1) is no longer generally applicable, since the staff agreed to remove the utility boiler pound-per-hour emission limits. The staff disagrees that §117.119(e)(1) only applies to utility boilers. This paragraph is intended to apply to each unit which monitors emissions directly. Regarding fuel use recordkeeping, the staff notes that the proposed paragraph in the industrial head, §117.219(f), requires hourly records of fuel burned as well. Hourly fuel use is generally needed to calculate hourly emission rates. However, since the staff has established 24-hour and 30-day emission rate limits, the staff has reconsidered the requirement to maintain hourly fuel use records for each affected unit in both the utility and industrial sections of the proposed rule. In order to simplify recordkeeping, the staff has required that all applicable records be maintained at a frequency equal to the applicable emission specification averaging period, or monthly, for exempt units. Regarding auxiliary boiler notification, reporting, and recordkeeping requirements, the majority of §117.119 reflects current NSPS requirements. In order to further simplify the §117.119 requirements, the staff allows in §117.113(d) an option to allow auxiliary boilers to comply with any applicable monitoring requirements under 40 CFR Part 60.

GHASP recommended requiring notification and reporting be provided to local agencies, in addition to the TACB, for cold start-ups or shutdowns, performance testing, and continuous monitor evaluations. The staff agrees with the comment and has changed the proposed rule language to allow the local air pollution control agencies to be notified of testing and receive test reports, since these procedures are standard convention with the local air pollution control agencies.

GHASP recommended requiring that, for any exceedances, notification be provided to the TACB within 24 hours, a written report provided within ten days, and a summary report submitted within three months. The staff's intent in requiring notification and reporting of exceedances is to facilitate enforcement. Little would be gained by requiring notification and reporting any sooner after the occurrence of an exceedance than is currently recommended. The reporting of exceedances within three months after a violation is timely enough to allow vigorous and effective administration of enforcement procedures.

EPA suggested that §117.119(a) and (e) require that records be made available to EPA, as well as the TACB, upon request. The staff agrees, and has revised §117.119(a) and (e) accordingly.

EPA suggested that the first sentence of §117.119(d)(5) be revised to read "...unless otherwise requested by the Executive Director of the TACB." The staff agrees, and has revised §117.119(d)(5) accordingly.

Section 117.121-Alternative Case Specific Specifications. GHASP recommended consideration of environmental control and effects on human health, welfare, and the environment in determining approval of alternative emission specifications. Section 117.121 states that approval of alternative emission specifications is "based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology." Approval depends on a unit's mitigating circumstances. Since the determination is based on a unit's capability, technological and economic considerations are the relevant circumstances in determining appropriate alternative emission specifications and the language of §117.121 reflects this. The effects on human health, welfare, and the environment are always important considerations in making pollution control decisions.

EPA commented that §117.121 does not make clear how "substantially equivalent emission reductions" would be determined. This comment has been superseded by a subsequent EPA letter. See the response at §117.121 and §117.221 to EPA's comment regarding alternate case specific specifications.

EPA withdrew its earlier comment that alternate RACT had to be based on substantially equivalent emission reductions, but instead could be based on technical and economical considerations. Also, EPA suggested that a plant using a system-wide emission limit not be allowed to apply for an alternate RACT limit for any unit in the system. See the response at §117.221 to EPA's comment regarding alternate case specific specifications. Language has also been added specifying procedures for appealing the Executive Director's decision to the board. See the response at §117.550 to comments of TCC et al. regarding permit requirements.

Although unaffected by the current proposal, Texas Utilities Services, Inc. (TU) submitted comments. It submitted comments out of concern that the proposed rulemaking will set the precedent for the development of NO_x RACT rules for the Dallas/Fort Worth area. It contended that the proposed limits are too low for natural gas, wall-fired utility boilers; do not follow the guidance of EPA's presumptive RACT limits; do not represent a reasonable first step toward ozone attainment; are too costly when compared with those for similar industrial sources in other states; and create an unnecessary economic burden. Therefore, limits should be set at EPA recommended levels until the UAM is performed.

TU recommended deleting the proposed CO emission limits and monitoring requirements, and argued that the ammonia emission limit should be deleted from the rule. It also recommended that emission limits be based on a 30-day averaging period, and supported the 0.30 lb NO_x/MMBtu limit for fuel oil-firing if applied only during the ozone season. It suggested that sources complying with the system-wide averaging of §117.107 be allowed to include units firing fuel oil or a mixture of fuel oil and natural gas in their system-wide average, instead of having to comply with a single, fixed emission limit.

TU's specific concerns were also expressed by other commenters and are addressed by the staff elsewhere in this evaluation of testimony, except for the following issues.

The staff does not agree with setting RACT limits at EPA-recommended levels until UAM modeling is performed. The staff sought to postpone NO_x RACT rules in the Dallas/Fort Worth area until completion of modeling because previous UAM modeling suggested that there would be little or no ozone benefits from NO_x reductions. To go forward with NO_x reductions in an area where lower observed VOC/NO_x ratios and modeling suggest little benefit and could not be cost-effective if following EPA's utility NO_x RACT recommendations resulted in the need to reduce actual emissions.

Concerning the application of fuel oil limits only during the ozone season, the staff has retained a year-round emission limit. Although TU derives minimal heat input from fuel oil firing, particularly during non-peak ozone months, the emission specification for fuel oil firing is intended to cover circumstances in which a utility chooses to burn fuel oil more extensively. Year round emission limits are applied to prevent excessive emissions and possible ozone exceedances during those months.

The staff disagrees with the idea of including units firing fuel oil in a system-wide averaging plan. Units operating on fuel oil, or a combination of fuels, could be included in a systemwide average, thereby raising the system-wide emission limitation and creating allowances for other units in the system to operate at higher emission rates. This could occur because system-wide averaging is based on a unit's heat input at maximum rated capacity, instead of actual heat input rate. High-capacity units could then produce greater NO_x emissions, up to the amount allowed by including the oil or gas/oil unit in the system-wide average, while the liquid fuel-fired unit operates at low loads. This inconsistency has the potential to create RACT equivalency problems resulting in EPA's disapproval. Historically, oil firing in electric utility units in Texas has been due to emergency natural gas curtailments. These periods usually represent only a few hours of operation per year. Allowing emissions averaging with an emission limit 50% higher than normal and based on such a low annual capacity factor would definitely result in the system-wide emission limit producing fewer reductions than individual limits.

Industrial Costs-General. Oxy commented that Chapter 117 does not follow the RACT guidance set forth in EPA's *NO_x Supplement* to the General Preamble, and recommended that the rules not be stricter than EPA's guidance. Mobil commented that the rules go far beyond RACT and sometimes exceed Best Available Control Technology (BACT).

In the *NO_x Supplement* to the General Preamble, EPA addresses certain issues pertaining to NO_x RACT which were either covered in insufficient detail or not covered at all in the original General Preamble. The NO_x Supplement was intended by EPA to serve as an adjunct to, not a replacement for, guidance previously furnished to the States to aid in their development of NO_x RACT rules. Of primary importance are the ACT documents, which contain background information on source emissions, control technologies and their availability, and control costs for categories of stationary sources which emit more than 25 tons per year of NO_x. The staff has relied extensively upon the ACT documents in its development of NO_x RACT rules. In particular, the proposed rules for gas turbines, internal combustion engines, industrial boilers, and industrial process heaters generally conform to EPA's RACT guidance contained in the ACT documents.

It is important to note that the *NO_x* Supplement to the General Preamble suggests numerical emission limits only for certain utility boilers. Conformance with these recommended RACT limits for utility boilers is discussed in the response to HL&P's comment regarding Utility Electric Generation, Utility Costs-General. Under §4.6, "RACT for Certain Electric Utility Boilers" in the NO_x Supplement, EPA suggests that RACT for other utility boilers and other source categories not addressed in the Supplement be set at "comparable" levels, taking into consideration cost, cost-effectiveness, and emission reductions. By adhering to the guidance contained in the ACT documents, the staff believes that EPA's criteria for acceptable RACT limits have been satisfied.

With regard to the rule being more stringent than BACT for new source review, it should be noted that after November 15, 1992, BACT is no longer the review criterion for permitting new or modified major stationary sources in the Houston/Galveston or Beaumont/Port Arthur ozone nonattainment areas. Under the updated new source review rules, major net increases by these sources must apply controls representing the lowest achievable emission rate (LAER) and obtain emission offsets in order to construct and operate. The NO_x RACT rule for existing sources generally follows very closely EPA's guidance in the ACT documents. In cases where the TACB rule is more stringent than EPA RACT guidance (most notably for utility boilers), strictly applying the suggested EPA limits would have resulted in no emission reductions at all. Rather than require large reductions from some sources at the expense of other sources which might require little or no reductions, the staff has sought to accomplish modest reductions overall while distributing the burden of emission abatement equitably.

Amoco Chem and Amoco Oil stated that the staff should publish reduction targets which quantify the NO_x reductions needed from mobile and stationary sources in each ozone nonattainment area, and suggested that the staff define a "reasonable" cost per ton NO_x reduced and implement rules starting with the most cost-effective control strategies.

In an ideal situation, the ultimate level of emission reductions required to attain the ozone standard would be available before the rule development process ever began In actuality, the TACB will rely heavily on the UAM to develop predictive scenarios in each ozone nonattainment area, showing ozone reductions obtained from various combinations of VOC and NO_x reductions. Preliminary first-round UAM results for the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas are not expected until early 1994. Useful as the data may be, the UAM's role at this preliminary stage will be limited mainly to confirming directional guidance in the overall ozone control strategy and allowing an initial attainment SIP to be written. Further modeling will be conducted after 1994 to fine-tune predictions of necessary reductions from mobile and stationary sources. The reduction targets obtained from the 1994 modeling may be modified downwards as a result of the post-1994 modeling. However, the available evidence from UAM runs nationwide suggests that the estimated 20% NO_x reduction obtained from major sources (10% overall) from first-round NO_x RACT will not be sufficient to attain the ozone standard.

With regard to implementing rules with priority given to the most cost-effective controls, the staff believes that it has taken such an approach since the first meetings with industry began in March of 1992 to discuss the NO_x RACT rules. Some control requirements initially considered by the staff have been postponed until the next round of rulemaking so that industry can start to work now on technically feasible NO_x reduction plans at a reasonable cost. The plant-wide emissions averaging concept in the rule gives industry much flexibility in applying the most cost-effective controls first.

Enron recommended that the staff evaluate lost revenues in its analysis of the rule's economic impact. The evaluation of lost revenues resulting from installation of controls to comply with the rule is a complex issue. Ideally, retrofits should occur during scheduled outages so that lost revenues may be minimized during plant shutdowns. For gas turbine cogeneration, many factors will determine the net economic balance between the additional cost of fuel to produce steam for turbine NO_x abatement, and the extra revenues gained from electricity produced with the steam The early implementation of NO_x RACT gives cogeneration sources additional knowledge about such changes as increases in output capacity, which may be relevant in renegotiating upcoming electric contracts. In any case, the staff would need much more detailed information about revenue structures and long-range economic planning in the cogeneration industry in order to properly evaluate lost revenues. EPA is expected to develop replicable procedures for allowing phased RACT beyond May 31, 1995. It is not known whether the schedules for major overhauls of gas turbines would provide a basis for justifying phased RACT

Waukesha commented that the staff underestimated control costs for internal combustion engines. The staff used cost information from control equipment vendors and the draft ACT document for internal combustion engines to arrive at cost figures for installing nonselective catalytic reduction and air/fuel ratio controllers on rich-burn engines. The staff recognizes the validity of other sources of cost data such as that provided by the commenter, and believes that, regardless of the particular method used to estimate costs, the cost-effectiveness range obtained (about $350-650 per ton NO_x reduced) is still a very reasonable figure.

Southern Union Company (Southern) commented that use of natural gas engines can provide lower overall emissions than electric motors. The staff disagrees that natural gas-fired engines emit less NO_x than electric motors deriving power from fossil fuel-fired power plants. In fact, the NO_x emissions produced per cubic foot of natural gas burned in reciprocating internal combustion engines are much higher than NO_x emissions generated from external combustion sources such as utility boilers in the production of equivalent power for electric drive motors. The conversion of heat to work has an efficiency of about 35%, whether the power is obtained from a gas-fired engine or a fossil fuel-fired power plant. An engine controlled to 2 0 g NO_x/hp-hr emits 0.60 lb NO_x/MMBtu, which is comparable to coal-fired utility boiler emissions and is three times higher than the allowable limit for gas-fired utility boilers proposed in the present NO_x RACT rule.

DuPont commented that CEMS do not reduce NO_x but greatly increase cost of implementing the rule, and that the TACB should allow parametric monitoring.

Although a CEMS unit does not function as a NO_x control device per se, the NO_x emissions data collected by a CEMS do play a vital role in alerting the operator to certain conditions which can result in excess NO_x emissions. Thus, the importance of a CEMS unit as a tool for facilitating emission reductions cannot be underestimated. Moreover, the contributions of CEMS data industry-wide will be instrumental in helping to develop emissions trading programs, set emission limits in future rulemaking, and improve the accuracy of the emissions inventory and inputs to the UAM

The staff is not opposed to parametric monitoring in principle, but believes that certain issues regarding the ability of parametric methods to accurately predict NO_x emissions should be resolved before implementing a parametric approach across the board For the meantime, use of CEMS to measure emissions directly is a proven method for determining emissions, and its investment value extends far beyond the immediate concerns of the present rule. The staff also believes that, aside from these general benefits, the cost of CEMS can be partially justified solely on the need to effectively enforce the rules.

TMOGA, Amoco Chem, Amoco Oil, Chevron, Mobil, Oxy, HL&P, and GHP commented that the staff has underestimated costs for CEMS, stack testing, and overall implementation of the rule.

The staff initially used EPA CEMS cost estimation methods to arrive at a projected capital cost of $125,000 per CEMS unit and an annual operating cost of $71,000 per unit Using TCC's figures, the cost estimates were $250,000 capital cost and $57,000 annual operating cost per unit. Information received from an equipment vendor on actual operating experience for dilution CEMS indicates typical annual operating costs less than $10,000 per year. New Jersey estimates annual operating costs for gas turbine CEMS, which mainly use extractive systems, to be in the range of $10,000-15,000 per unit. Since annual operating costs dominate the overall cost of CEMS, the staff most likely overestimated these costs in its projections. The staff recommends allowing as many as three emissions units to share one NO_x CEMS, which should further reduce the costs of rule implementation.

In its estimates of stack sampling costs at about $2,000 per test, the staff assumed that the average cost per test would decrease with multiple tests being conducted at the same plant. Amoco Chem's and Amoco Oil's estimates of $5,000-15,000 per test may be valid for a single test, but usually not for multiple tests at a single plant. The staff has not included costs for installing sampling platforms and ports in its estimates to date, but will continue to provide guidance on the placement and installation of such items.

With regard to staff cost-estimates for overall implementation of the rule, some variation in published control cost figures is to be expected. The staff relied to a large extent upon the EPA Office of Air Quality Planning and Standards document, "The Clean Air Act Section 183(d) Guidance on Cost-Effectiveness" (EPA-450/2-91-008, November 1991), for guidance on cost-effectiveness of NO_x control measures for various source types. Generalized cost estimates across the industry for a class of sources usually cannot completely account for individual differences among sources within that class. Thus, while other commenters' cost estimates may be equally valid, the staff believes that the use of EPA's cost figures is a judicious and technically defensible approach.

For industrial boilers and heaters, the lack of certain data from individual units such as monitored emissions, one-time emission tests, heat input capacity, furnace volumes, and firebox temperatures makes cost estimation difficult. The staff has incorporated some of industry's suggestions in developing these limits, and waits for initial control plans from affected sources before reassessing control costs.

Section 117.103-Exemptions. Regarding §117.203, concerning Exemptions, Sterling Chemicals (Sterling) requested that TACB consider the performance capabilities of combustion sources burning waste fuels containing organic nitrogen and recovering waste heat. Sterling recommended that instead of setting alternative RACT standards in §117 221, TACB should retain the flexibility to exempt such sources from RACT standards altogether See the earlier response to Texaco's comment in §117.205 for the staff's position on boiler and industrial furnace (BIF) units. If, after the application of reasonably available control technology, the unit cannot meet the RACT limit, then the affected person can make an application to the Executive Director for a different emission limit through §117.221. The staff believes that exempting these sources now will not keep them from having RACT limits placed upon them in future rulemaking.

TCC, TMOGA, Exxon Chem, and Exxon suggested that references to "cold start-up and shutdown" in §117.203(a) be deleted and that the rule should reference the General Rules regarding major upset and maintenance. They also suggested that this subsection reference §117.207, as well. GHASP opposed exemptions for start-up and shutdown emissions. The staff agrees with the commenters (TCC, TMOGA, Exxon Chem, and Exxon) that references to cold start-up and shutdown of units be deleted and that the rule should defer to TACB's existing General Rules regarding major upset and maintenance (§§101.6, 101.7, and 101.11). The staff disagrees with the comment by GHASP that the rule should not exempt these emissions because the comment does not consider the existence of the provisions of the General Rules. See the responses at §117.10 to TCC's comment regarding the definitions of cold start-up and shutdown and GHASP's comment concerning the definition of emission rate. The staff is interested in reproposing definitions in future rulemaking to address this issue. The staff has deleted the definitions for cold start-up and shutdown in §117.10 and the references to start-up and shutdown in §117. 203(a).

Air Products and Chemicals, Incorporated (Air Products) suggested that landfill gas recovery facilities should be exempt from the NO_x RACT rule, claiming adverse economic impact of controls and inherent environmental benefits provided by such facilities. Air Products requested exemption of its natural gas-fired engines located at a landfill. The staff agrees that the contaminants found in the waste gas that is produced in a landfill can cause unacceptable degradation of catalytic converter performance. However, there are other control techniques such as prestratified charge which may be applied reasonably on a retrofit basis. In Air Products' case, fuel quality is not an issue since it has converted to natural gas fuel. The staff disagrees with Air Products' contention that the difference between its current 5.0 g NO_x/hp-hr limit and the proposed RACT limit would impose unreasonable additional costs on its facility. If its catalyst life is actually three-five years, it will be able to replace its catalyst with a new charge to meet the 2.0 g NO_x/hp-hr limit within its anticipated maintenance schedule, prior to the May 31, 1995, final compliance date of this rule. The staff believes that adding a layer of catalyst to the existing catalyst or cleaning it more frequently may be more cost-effective methods of obtaining compliance with the proposed emission limit. The staff also notes that the cost of installing the natural gas pipeline to the facility is not related to the proposed rule.

TCC, Exxon Chem, Exxon, Mitchell Energy Corporation, and EPA suggested rewording §117.203(b)(1) to reflect that new rich-burn engines are subject to §117.206, relating to Emission Specifications for New, Rich-Burn Engines. The staff has deleted the proposed requirements for new sources in §117.206, making the suggested wording unnecessary. See response to Manufacturers of Emission Controls Association's (MECA) comment under §117.206.

TMOGA and Mobil suggested that units which had undergone a BACT review and were granted a permit to start-up at the time of promulgation of the rule be exempted. Amoco Chem and Amoco Oil requested that §117.203(b)(1) be retained as proposed. The staff does not agree with TMOGA and Mobil on the suggestion to exempt any permitted source from RACT controls. BACT is an evolutionary standard, so the earliest permits written by the TACB may not represent RACT today. A clear line between existing units subject to RACT and those which are not (because they are new sources) needs to be drawn. The rule is proposed to affect sources in existence prior to November 15, 1992, the FCAA Amendments date by which the NO_x RACT rules were to be promulgated. Other advantages of including BACT permitted units placed into service prior to November 15, 1992 are that a minimum uniform level of testing, monitoring, recordkeeping, and reporting requirements is established. Including existing BACT units in the RACT rule also gives more flexibility for persons to place additional controls on units when this is cost-effective.

Sterling operates a number of combustion units which incinerate very low Btu off-gas from air oxidation processes with supplemental fuel. Sterling's opinion is that these units are exempt from emission limitations because these units are incinerators. The commenter is concerned about possible confusion between boilers, which are subject to the rule, and incinerators, which are exempt. The staff notes the EPA definition of boiler in 40 CFR 260.10, which states that a boiler is an enclosed device using controlled flame combustion and having the following characteristics: the combustion chamber and primary energy recovery section must be of integral design; thermal recovery efficiency must be at least 60%; and at least 75% of the recovered energy must be "exported" (i.e., not used for internal uses such as preheating of combustion air or fuel, or driving combustion air fans or feed water pumps). The staff suggests Sterling consider this definition to determine whether or not the combustion units that burn low Btu off-gases are boilers or incinerators.

Sterling requested clarification as to whether the exemption in §117. 203(b)(6) applied only to gas-fired engines. Sterling also requested clarification as to whether the exemption in §117 203(b)(6)(A) applies to periodic testing of equipment. Sterling suggested that periods of testing not be included in the allowed hours of operation. The exemptions in §117 203(b) (6) are not intended to apply only to gas-fired engines. The proposed wording states "engines." Liquid fuel-fired engines operating in these services or at these hours are also exempt. For simplicity in enforcing the hour-per-year limitations with a run-time meter, all hours of engine operation, including those for test purposes, are to be included. However, the staff recommends increasing the number of hours allowed under this exemption to cover both testing and minimal service, as discussed in the response to suggestions to raise the number of hours allowed, under §117.203(b)(6)(C) as follows.

Exxon Chem suggested adding "such as a loss of power" to the definition of any officially declared disaster or state of emergency, in §117.203(b)(6)(A). The staff believes that a loss of power does not necessarily constitute an officially declared disaster. The operating hour exemption in §117 203(b)(6) (B) provides for the operation of engines and turbines during losses of power which are not officially declared disasters.

GHASP objected to the exemption of gas turbines or engines used exclusively in agricultural operations. Due to the generally small size and seasonal operation of gas engines used in agricultural operations, the staff considers the exemption of such sources to be technically and economically justified. The staff has retained this exemption as proposed.

TCC and TMOGA recommended that the annual low capacity factor in §117. 203(b)(6)(C), qualifying engines and turbines for exemption, be raised from 200 hours per year to 850 hours per year. Exxon Chem and Exxon suggested raising the figure to 876 hours per year, and Star Enterprise (Star), to 438 hours per year. GHASP objected to the exemption of industrial peaking gas turbine units, since these units often operate in the high ozone season. Stationary industrial engines and turbines often run either close to continuous operation or less than ten percent of annual capacity, about 850 hours per year. Requiring emission controls for equipment which is limited to run no more than ten percent of annual capacity is not cost-effective. Considering the magnitude of NO_x emissions generated continuously by other sources on a year-round basis, the exemption of the relatively few peaking units for the reasons cited appears reasonable. The staff hs raised the annual low capacity factor for both utility and industrial gas turbines and internal combustion engines to 850 hours per year. The staff also has revised rule sections relating to exemptions for both utility and industrial sources, and continuous demonstration of compliance, to reflect this change.

TCC, TMOGA, Amoco Oil, and Exxon Chem objected to the permanent loss of exemptions if the hours-per-year limit is exceeded for gas turbines or engines. The staff intends "permanent loss of exemption" to mean that if a unit exceeds the given exemption levels, then it has to comply with the applicable emission limits from that point on. The staff believes this is a reasonable requirement which will prevent abuse of the exemptions for equipment which would not otherwise meet the exemption requirements.

EPA suggested adding the word "calendar," revising the phrase to read "less than 200 hours per calendar year," thus making it consistent with the wording in §117.203(b)(6)(B). The staff agrees, and has revised §117.203(b)(6)(C) to include the word "calendar."

Association of Texas Intrastate Natural Gas Pipelines (ATINGP) commented that engines rated 150 hp are unlikely to emit the 25 tons per year or 50 tons per year of NO_x specified as major in the Houston/Galveston or Beaumont/Port Arthur ozone nonattainment areas, respectively. Exemption limits for internal combustion engines were computed by back-calculating from the minimum yearly NO_x emissions qualifying a source as major (25 tons per year in the Houston/Galveston area), using an emission factor of 18 g NO_x/hp-hr and assuming continuous operation. The 18 g NO_x/hp-hr emission factor represents manufacturers' emission estimates for a typical rich-burn engine operating at the best fuel economy carburetor setting. The engine rating of 144 hp thus calculated was rounded up to 150 hp since operation is always less than 100% of capacity, resulting in a 150 hp exemption limit for affected internal combustion engines in §117. 203(b)(8). This calculation shows that an engine rated at 150 hp emits right at the 25 tons per year level defined as major for the Houston/Galveston area, but emits at about half the 50 tons per year level qualifying it as major in the Beaumont/Port Arthur area. In order to correct for this disparity, the staff has raised the exemption level in §117.203 for rich-burn engines in the Beaumont/Port Arthur area to 300 hp and revised other rule sections accordingly.

Section 117.205-Emission Specifications. Regarding §117.205, concerning Emission Specifications, Oxy stated that thermal reactors and process heaters should be exempt from Chapter 117 since they are not mentioned in the EPA's *NO_x* Supplement to the General Preamble. The staff does not agree with Oxy that thermal reactors and process heaters should be exempt from the rule. The FCAA Amendments require NO_x RACT to implemented on all major sources; EPA interprets "major" to mean both individual units and collections of units at a plant with potential major emissions. Even though process heaters are not specifically mentioned in the *NO_x* Supplement to the General Preamble, EPA states, "other source categories can be important in individual areas." Recognizing the importance of NO_x emissions from process heaters, EPA has prepared an ACT Document entitled *NO_x* Emissions from Process Heaters (draft September 1992; final February 1993). The staff believes that the regulation of thermal reactors and process heaters is appropriate because of the large population of these units in the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas.

Oxy stated that the *NO_x* Supplement to the General Preamble specifies NO_x emission limits only for large boilers. Oxy suggested that TACB adopt similar procedures for RACT determination for smaller units. The staff does not agree that RACT for boilers and heaters which are smaller than 250.0 MMBtu/hr heat input should be established on a case-by-case basis as implied as an option in the General Preamble. The staff has used the ACT for process heaters, as well as other documentation, to establish emission limits for process heaters and industrial boilers less than 250.0 MMBtu/hr heat input. Section 117.221 allows for caseby-case determinations, in the event that the affected person cannot meet the RACT limits individually in §117.205, or through plant-wide averaging in §117. 207.

TCC, TMOGA, Amoco Oil, Chevron, Dow, Exxon Chem, Exxon, Mobil, Oxy, Phillips Petroleum Company (Phillips), Shell Oil Company/Shell Chemical Company (Shell), Sterling, and Champion International Corporation (Champion) requested that TACB change the hourly averaging period for affected units to a rolling 30-day average; Texaco and Star recommended a 24-hour average as a minimum.

The staff agrees with the commenters and has included a 30-day rolling average emission limit in lb NO_x/MMBtu, calculated each day as the average of all the hourly data for the preceding 30 operating days for industrial boilers and process heaters which are monitored with a CEMS. The benefits to industry of long-term compliance averaging are the ability to assign lower emission limits to units and the reduction or elimination of exceedances caused by short-term emission fluctuations. The compromise facilitates progress on implementation of a first-round emission reduction rule. Reducing the likelihood of compliance problems may further industry's willingness to make deeper emission reductions, which are probably needed.

The TACB will benefit from the better information for ozone attainment planning as emission limits become more representative of actual emissions. In the presence of numerous sources in an area or grid, the short-term NO_x emissions in the aggregate are far more uniform than the short-term emissions of individual units. Although some commenters suggested a compromise of a 24-hour averaging period (Texaco and Star), the staff has included the rolling 30-day average. However, the staff does not agree that a 30-day rolling average should apply for CO and ammonia limits. The one-hour averaging period for CO is due to the direct relationship between CO emissions and the primary, one-hour averaging period of the CO NAAQS. In contrast, the relation between NO_x emissions and the ozone standard is not as well defined but is thought to be dependent on longer term emissions. The staff recommends increasing the ammonia limit to 20 ppmv but changing the averaging period to one-hour to simplify compliance testing. Refer to the response to Exxon at §117.205(e) for more detail on the ammonia slip-emission limit.

TRC suggested incorporating a RACT limit for petroleum coke-fired boilers of 0.55 lb NO_x/MMBtu based on a rolling 24-hour average into §117. 205(a). Due to the way the *Texas Register* interprets APTRA to require public notice in the *Texas Register* for any new emission limitations, the staff has not incorporated an emission limit for petroleum coke-fired boilers into §117 205(a) at this time.

Exxon Chem suggested deletion of the term "detailed" from units "subject to a detailed NO_x best available control technology review" at §117. 205(a)(2).

The intent of the proposed §117.205(a)(2) is to allow newer boilers and heaters placed into operation in the last ten years, which have undergone review in accordance with a TACB NO_x BACT permit guideline effective March 1982, to be allowed the permit emission limit as the RACT limit. The guidance for industrial boilers and heaters rated more than 40 MMBtu/hr heat input was that BACT should be considered 0.12 lb NO_x/MMBtu heat input, lower heating value, for gas fuel, which is the primary industrial fuel on the Texas Gulf Coast. The policy memo was in response to the development of new burners specifically designed to reduce NO_x emissions, which now could be called "first generation" LNB. As discussed in the staff's June 1992 NO_x RACT position paper, the intent of the TACB's NO_x RACT rule was (and is) that units subject to these specific BACT limits after March 1982 would not be required to lower their NO_x limits further under a RACT rule. The incremental reductions obtained by going from first-to second-generation LNB will be less cost effective than going from uncontrolled emissions to second generation LNB and was not considered RACT The staff also notes that 0.12 lb NO_x/MMBtu lower heating value, is approximately equal to 0 11 lb NO_x/MMBtu, high heating value. The RACT rule is based on high heating value Thus, the BACT limit for these units is very close to the lowest of the proposed RACT limits The staff believes that the relative recency and stringency of the March 3, 1982 memo provides a technically justifiable basis for establishing RACT for these boilers and heaters.

The issue is complicated because of the fact that BACT is handled case-by-case. In some instances there may have been sufficient documentation to demonstrate that a limit higher than 0.12 lb/MMBtu was appropriate for gas-fired boilers or heaters, but these are expected to be very few. The intent in using the word "detailed" is to avoid assigning BACT limits which are less stringent than the RACT limits of §117.205(a)(3) in cases where there is no technical justification. The term was proposed to reduce the possibility of confusion as to whether a unit's NO_x emissions have been subject to new source review under Chapter 116. A common TACB Permits Division practice is to incorporate emission limits for grandfathered units into the maximum allowable emission rate table of a permit in cases in which no NO_x BACT control requirements have been imposed on the equipment, for codification purposes. Another possibility is that a unit constructed or modified under a permit involving NO_x BACT review issued after the March 3, 1982 memo establishing specific guidelines for TACB Permits Division NO_x BACT review for industrial boilers and heaters was "grandfathered" from the policy because of the length of time the permit application was pending review prior to the new policy, or the policy may have been overlooked. Cases in which existing boilers or heaters were included in a permit are of concern. Reliance on EPA AP-42 emission factors would clearly show that detailed BACT review had not occurred, but other situations are likely to be less clear-cut.

The technical staff believes that a BACT review after March 3, 1982, which includes a sound technical basis for allowing a higher limit than the TACB BACT policy memo limit is justification for setting the RACT limit equal to the BACT limit, even if the §117.205(a) (3) emission limit is lower. However, the standard as proposed may lead to difficulty in implementation in a consistent manner. After discussing the issue further with TACB legal counsel, the staff has reconsidered the issue of including the term "detailed" and has deleted it.

EPA now takes the position that the rule may not be approvable unless the lower of the RACT emission limits of §117.205(a)(3) or the permit limit apply. A February 28, 1990 EPA policy memo from John Calcagni to the EPA Regions is relevant to this issue. The memo states: "We are aware that certain old LAER emission limits are less stringent than reasonably available control technology (RACT) that have been more recently established for some new stationary sources in the ozone nonattainment areas of various Regions. This is an expected result of control technology continuing to improve. The old LAER limits do not preempt RACT in these cases, and in fact, the more recent RACT limits may redefine LAER for future determinations."

The staff notes conversely that if a BACT limit is more stringent than the RACT limit, the BACT limit governs and must be used in calculating the plant-wide allowable emission. Not to do so would allow double crediting of emissions reductions under BACT and RACT Gas turbine facilities of Phibro Refining, Union Carbide/Linde, and possibly a few others were placed into operation prior to November 15, 1992 (hence "units" for rule purposes), at a 25 ppmv NO_x limit. The EPA and the TACB could not allow a more stringent BACT limit to provide an emissions credit for these sources under plant-wide RACT averaging, since this reliance on the same reductions would be "double counting." However, if a BACT unit is economical to control, a company may choose to assign and take credit for an allowable emission under the plant-wide average which is more stringent than the BACT limit.

EPA would prefer that the more stringent of an applicable LAER, BACT, or RACT limit would be used to define RACT for averaging purposes. A modification to the rule for clarification will be proposed in the second round of rulemaking for the summer of 1993.

Mobil stated that §117.205(a)(2) and §117.203(b)(1) are redundant. The RACT rules were proposed for existing equipment placed into service prior to November 15, 1992. If the industrial boiler and process heater units had undergone a BACT review after TACB set permit NO_x BACT guidelines for heaters and boilers, then their RACT emission limit would be the BACT emission limit specified in the permit. The other requirements of this proposed regulation concerning recordkeeping and monitoring requirements are RACT requirements that are required for all units affected by the rule. The staff has retained the wording as proposed.

TRC has suggested that if they revise the emission limit downward in their current permit, it is possible that the limit will not be federally enforceable. If the lower limit was not federally enforceable, the TACB might not be able to take credit for the paper reductions in the attainment modeling. TACB Regulation VI (Chapter 116) has been submitted to the EPA and approved as part of the State of Texas' SIP. The TACB permits are considered to be federally enforceable by EPA.

TRC suggested that TACB clarify the applicability of the proposed §117. 205 to the petroleum coke-fired boiler operated at AES Deepwater. TRC pointed out that the current TACB permit for the unit has a BACT limit of 0.70 lb NO_x/MMBtu and that the unit has incorporated all the latest design techniques for the reduction of NO_x. TRC believes that the permitted limit would be RACT for the petroleum coke-fired boiler. The staff has discussed the applicability of the rules to this particular unit in the response to TRC's comment in §117.10. The staff has not been able to verify that the unit has had all the latest NO_x design techniques installed. The staff does agree that the permit limit for the unit will qualify as the RACT limit according to the specifications of the proposed §117.205(a)(2).

Chevron expressed the appreciation of limiting the applicability of the rule to boilers and heaters greater than or equal to 100.0 MMBtu/hr heat input Oxy stated that emission limits below 0.20 lb NO_x/MMBtu are too stringent for units greater than or equal to 100.0 MMBtu/hr heat input. Oxy referred to the *NO_x* Supplement to the General Preamble in citing limits for these type of units.

EPA has informed the TACB of the need to develop RACT specifications for all major sources including industrial boilers and process heaters less than 100.0 MMBtu/hr heat input. The staff disagrees with the comment that the limits below 0.20 lb NO_x/MMBtu are too stringent for units greater than or equal to 100.0 MMBtu/hr heat input based on the *NO_x* Supplement to the General Preamble. The NO_x Supplement states that the limits for certain utility boilers shall be 0.20 lb NO_x/MMBtu for tangentially fired, oil/gas burning units and 0.30 lb NO_x/MMBtu for wall fired, oil/gas burning units. The Supplement then states that NO_x RACT for other sources will be set at levels that are comparable to these limits.

The staff plans to achieve modest first round reductions for both utility and industrial boilers. The staff has set comparable emission limits for units greater than or equal to 100.0 MMBtu/hr heat input based on EPA ACT guidance, CARB/SCAQMD limits, and industry workgroup meetings. Furthermore, the Supplement states in §4.2 that EPA has historically recommended source-category-wide presumptive RACT limits, and plans to continue this practice.

TCC, TMOGA, Amoco Chem, Amoco, Exxon Chem, Exxon, Mobil, and Texaco suggested new emission limits considering extremely high firebox temperatures and to allow a choice between emission limits based on firebox temperature and preheated air temperature Exxon Chem and Exxon both proposed a table that incorporates limits based on firebox temperature and preheated air. Amoco Chem and Amoco Oil also made a statement that induced draft heaters are given no correction factors at all.

The staff has revised the process heater emission limits to allow for a choice between air preheat and firebox temperature effects on the gas-fired process heaters. The staff does not agree with the suggestion that we revise the section to allow a new emission limit for firebox temperatures of greater than 1,800 degree Fahrenheit. The staff believes this concern is adequately addressed in §117.205(a)(3)(C)(iii), which allows for a correction due to high firebox temperatures. In addition, the emission limits for units that have high firebox temperatures which have undergone BACT analysis in Texas are on the order of 0.08 lb NO_x/MMBtu using the same control technologies, which is consistent with the proposed levels of RACT for existing process heaters.

The proposed limits represent an agreement reached during work group meetings with the trade groups representing affected persons. Some of the commenters' proposed limits are actually more stringent than the proposed limits in the rule.

The type of draft was only used as a basis for differentiation between units using preheated air and units with elevated firebox temperatures Exxon states, "Our experience is that the type of process heat draft (mechanical or natural) has very little effect on NO_x emissions." This statement contradicts the statement made by Gordon Strickland, Vice President-Technical Services, Chemical Manufacturers Association, in a letter dated September 9, 1992, to William Neuffer with EPA.

Mr Strickland points out that forced draft NO_x emission factors are the same or even higher than natural draft emission factors in the EPA's ACT document on process heaters. Mr. Strickland states, "However, sometimes forced draft designs will give a reduction in NO_x (as much as 40 percent) versus natural draft burners, even without air of [sic] fuel staging." Once the staff made the decision to differentiate process heaters based on the type of draft, then factors affecting each type were researched. For mechanical draft units, the degree of preheated air showed the most effect on emissions; and for natural draft units, the firebox temperature showed the most effect. The emission limits were then evaluated and proposed on this basis.

The staff disagrees that induced draft heaters are given no correction factors. Induced draft heaters are included with mechanical draft heaters, since there is a mechanical device which either forces or induces draft to the heater. If the induced draft heater has air preheat, then emission limit allowances are given based upon the temperature of the preheated air. However, if there is no air preheat and the firebox temperature is high, the rule as proposed does not allow a correction based on its having an elevated firebox temperature. As a result, the staff has revised limits for gas-fired process heaters by deleting the reference to mechanical draft and natural draft. The resulting limits will provide an either/or situation. Either the heater will have an emission limit based on the temperature of the preheated air, or the heater will have an emission limit based on the firebox temperature.

Texas Petrochemicals Corporation (TPC) suggested using a heat release rate per unit area of water wall furnace tube instead of a volumetric heat release rate. TPC believes that the volumetric heat release rate is not as accurate.

The staff is retaining the use of the heat release rate as a volumetric standard based on and for consistency with EPA's definitions of heat release rate, high heat release rate, and low heat release rate in 40 CFR, §60.41b.

TPC suggested a new RACT emission limit of 0.28 lb NO_x/MMBtu for boilers with preheated air built before 1950. The staff disagrees with the comment that an emission limit of 0.28 lb NO_x/MMBtu for boilers built before 1950 utilizing preheated air be included in the rule TPC has not presented supporting documentation that the RACT emission limit suggested for this type of unit is proper. The proposed rule already takes into consideration boilers utilizing air preheat and the staff believes that this is sufficient.

TPC requested that the TACB consider the effects of firebox temperature for both gas-fired, mechanical draft process heaters and gas-fired industrial boilers. The staff has changed the gas-fired process heater emission limits to allow for a choice between either a limit based on firebox temperature or a limit based on the temperature of the preheated air. The staff disagrees with TPC on the subject of considering firebox temperature for gas-fired boiler emission limits. The proposed rule accounts for the heat release rate which indirectly accounts for the temperature in the firebox. The staff disagrees that furnace size is directly related to heat transfer surface and flame temperature. Boilers are meant for heating water and/or producing steam. The flame temperature typically is not as varied as it is among process heaters, and therefore is not considered to be a factor in setting emission limits for boilers.

TCC and Exxon Chem suggested a clarification of §117.205(a)(4) to show that some combustion units can have more than one fuel gas source, and that the total hydrogen content of all fuel gas streams must be greater than 50% by volume in order to receive a correction factor. The staff agrees with the need for wording changes to §117.205(a)(4), §117.207(h), and §117.213(f) to clarify the calculation of hydrogen by volume for fuel streams. The staff has added the clarification to each of the sections listed.

TMOGA, Mobil, and Texaco suggested a 1 125 multiplier for fuel gas streams containing 25% to 50% hydrogen by volume. Texaco suggested an allowance for fuel gas streams which contain anything less than 50% hydrogen by volume.

The ACT document for process heaters states, "One source reports that for a heater fired with fuel gas containing 50 percent or more hydrogen, NO_x emissions can increase 20 to 50 percent over the same heater fired with natural gas" (pages 4-8). None of the available data would indicate that hydrogen concentrations between 25% to 50% have a significant effect on NO_x emissions. The effects of increasing emission levels of NO_x are only noticed and documented in vendor tests for streams containing a minimum of 50% hydrogen by volume. For fuels with hydrogen concentrations less than 50% by volume, the commenters have not presented supporting documentation that the emission limits should be adjusted by a factor of 1.125. As a result, the emission limit multiplier for hydrogen will remain as it is instituted in the rule, without any additional multipliers for fuel gas hydrogen content.

Mobil also requested that the relaxation should not be limited to an eight-hour continuous period. The eight-hour period is the minimum time period in which the 1 25 multiplier can be used, since the sampling requirements will only show data for two or three sampling/analysis data points A shorter period for applying the multiplier would require shorter and more frequent sampling and analysis periods. The eight-hour time period in §117.205(a)(4) will remain as worded.

Chevron stated that the sampling and analysis requirement in §117.205(a) (4) for hydrogen should be once every 24 hours. However, Chevron withdrew the comment in a letter dated April 23, 1993. The staff believes that the sampling requirements for hydrogen containing fuels is attainable through the use of online gas chromatography or mass spectrometry. The use of on-line gas chromatography is fairly common in refineries for the analysis of hydrogen sulfide in the fuel gas (as required by NSPS, Subpart J, 40 CFR §60.104). Such analyses have data taken and recorded into computers which assist in recordkeeping requirements. The staff believes that one 24-hour sample is insufficient data to demonstrate that the hydrogen level was greater than 50% over that entire 24-hour period, let alone any eighthour period. The sampling requirements will remain as they were proposed.

TCC, Dow, Exxon Chem, Phillips, and Star recommended raising the gas turbine CO limit in §117 205(b) from 50 to 150 ppmv, and Exxon recommended 100 ppmv. Star and Champion suggested a 24-hour rolling average TCC, TMOGA, and Amoco Oil suggested eliminating the CO limit for gas turbines.

Section 117.205(b) proposes a 50 ppmv CO limit referenced to 15% O_2 for stationary gas turbines rated 10 MW or greater. In its review of part-load emissions data from General Electric, the staff determined that emissions higher than 50 ppmv at 15% O_2 are possible for industrial gas turbines Accounting for the difference between O2 correction terms, the gas turbine CO limit equivalent to 400 ppmv proposed for industrial boilers and heaters at 3.0% O_2 is 400/((20.9-3)/(20 9-15)), or 132 ppmv at 15% O_2 The staff has included this as the CO limit for industrial stationary gas turbines. The CO limit of 400 ppmv in §117.105(j) applies to all utility units, including utility stationary gas turbines. Due to APTRA requirements, the staff will revise the CO limit for utility gas turbines in future rulemaking. With regard to the suggestion to eliminate the CO limit for gas turbines, protection of the one-hour CO NAAQS necessitates adopting an emission standard and retaining the hourly compliance limit as proposed. See the response to HL&P's comment in §117.105 for additional discussion on CO limits

Champion commented that the staff estimates of steam injection control costs are underestimated, and recommended exempting gas turbines with control costs greater than $2,000 per ton of NO_x controlled. Champion projected a cost-effectiveness of $4,384 per ton of NO_x to control its two General Electric F5M' turbines.

The staff relied to a large extent upon EPA's ACT document on stationary gas turbines (final report issued January 1993) for its estimates of turbine control costs and cost-effectiveness. The cost figures for control to 42 ppmv NO_x for 12 model gas turbines are in the $500 to $2,000 cost-effectiveness range. The staff recognizes that for specific turbines the cost-effectiveness figures may be higher, but considers the proposed limits and typical cost ranges to be reasonable.

The staff has also found that estimating emission control costs is difficult. Although the General Electric F5M' model operated by Champion was not evaluated in the ACT document, a similar General Electric Frame 5 model rated 50% higher MW output than the F5M' was included in the ACT. The ACT's total annual cost estimate for reducing NO_x emissions from 142 ppmv to 42 ppmv, using steam injection, from the model Frame 5 turbine was $487,000, corresponding to $957 per ton NO_x reduced. It is not known whether Champion's cost figures reflect the effect of increased power output resulting from steam injection, which would partially offset the costs it cited. There is also the possibility that dry low-NO_x combustors instead of wet injection and the related turbine upgrades could result in better cost-effectiveness figures for NO_x emissions reductions.

Amoco Oil, Oxy, and Champion questioned the inclusion of CO emission limits in a rule that is meant to control NO_x. Mobil suggested that there be no specific limits for secondary pollutants in §117.205(d) and §117. 207(e), as long as the NAAQS standards are not violated. Oxy suggested that any increases in secondary pollutants should not have to be permitted if within allowable increases. CO limits are included in the rule because of the potential for increases in CO emissions when combustion modifications are made to reduce NO_x emissions The staff recognizes the need to protect the NAAQS for CO while in the process of attaining the NAAQS for ozone. The TACB is not staffed to enable case-by-case permitting of all the sources, that would require a review due to increases in CO or ammonia. The rule currently allows for exemptions from permitting for certain sources, and the concept of General Permits will be addressed in future rulemaking. See also at §117.105 the response to HL&P's comment regarding CO emission limits. The need for CO limits remains and the staff has retained the proposed limits.

Engine & Compressor Systems (ECS) commented that the NO_x emission limit for rich-burn engines manufactured prior to September 1982 should be raised to 5 0 g NO_x/hp-hr MECA recommended that the NO_x emission limit for rich-burn engines be lowered to 0 5 + 1.0 g NO_x/hp-hr. The staff believes the 2.0 g NO_x/hp-hr limit reflects RACT for rich-burn engines. The TACB Permits Program still uses 2.0 g NO_x/hp-hr as a BACT limit. The design basis for nonselective catalytic reduction (NSCR) evaluation in the ACT document for internal combustion engines is 2.0 g NO_x/hp-hr. A lower standard could also be reasonable, since under best operating conditions an NSCR catalyst on a rich-burn engine can virtually eliminate NO_x. However, an additional layer of catalyst may also be required to meet a more stringent emission limit. Performance of any catalyst degrades with time, eventually requiring catalyst replacement. The staff lacks field data on NSCR service life and is not able to estimate the costs of increased catalyst replacement which a lower standard would necessitate. If a more stringent limit results in relatively low incremental catalyst replacement costs, as the staff suspects, companies may be able to use the averaging elements of the rule effectively by assigning lower limits to some engines The staff would prefer that the cost-benefits of lower limits be evaluated by the companies in this case. Regarding the suggestion that rich-burn engines manufactured prior to September 1982 be allowed a 5.0 g NO_x/hp-hr limit, the staff recognizes that older engines may require engine maintenance in order for NSCR to operate properly. The staff believes it is reasonable to expect companies to perform engine maintenance if it is needed to comply with the 2.0 g NO_x/hp-hr limit

Exxon requested a 20 ppm ammonia slip-emission limit. The staff agrees and has added a 20 ppmv emission limit based on a one-hour averaging time period. This recommended change is to allow a more lenient emission limit for selective non-catalytic reduction processes which can require higher ammonia slip limits. The ten ppm increase in ammonia emissions is anticipated to be negligible in its effects on the environment. The new recommended averaging period change will allow compliance performance testing to be performed with greater ease

Enron expressed support for exempting heat recovery steam generators (HRSG) from emission limits in the proposed rule The staff agrees and has retained the HRSG exemption in the proposed rule. The staff does not think it likely that HRSGs may actually cause NO_x reductions at the proposed 42 ppmv gas turbine NO_x limit. See the response to Enron's comment at §117 207(f). The staff has some concerns about the calculation procedures used to compute gas turbine/duct burner emission rates, which continue to be investigated. The changes in moisture and oxygen content in the stream and the point of actual sampling need to be accounted for carefully in calculating relative emissions

Texaco requested clarification on the exemption of boilers and industrial furnaces (BIFs) regarding the time periods which BIF units actually burn hazardous waste The staff has exempted BIF units which burn hazardous waste and which are regulated as existing facilities by 40 CFR, Part 266, Subpart H If the unit is not classified as a BIF and the provisions of §117 201 apply to the unit, then the unit must comply with the rule If a unit is classified as a BIF according to 40 CFR Part 266, Subpart H, then it will be completely exempt from emission specifications in the proposed rule, regardless of the time periods in which it operates as a BIF unit.

MECA recommended that a reasonable emission limit be established for lean-burn engines, and stated that the absence of a limit would encourage the installation of more uncontrolled lean-burn engines (even if subject to new source review), or would result in the conversion of rich-burn engines to lean-burn to avoid controls.

With regard to possible consequences of not having an emission limit for lean-burn engines in the meantime, the staff does not agree that more uncontrolled lean-burns will be installed as a result. New source review requirements for ozone nonattainment areas in effect since November 15, 1992, call for the application of lowest achievable emission rate (LAER) (or BACT if the source nets out of nonattainment review). This may well amount to installation of electric drive motors in place of internal combustion engines, which are inherently high emitters of NO_x.

Further, the staff does not agree that rich-burn engines will necessarily be converted to lean-burn in order to avoid application of the rule. The proposed rule definitions of lean-burn and rich-burn engines specify that the exhaust gas O_2 concentration shall be determined from the uncontrolled exhaust stream. This means that once an engine has been built as rich-burn, it always remains a rich-burn engine for purposes of rule applicability. These definitions were included expressly to prevent circumvention of the rule by modifying a rich-burn engine to give it lean-burn characteristics. This would not preclude a rich-burn engine from being modified to a lean-burn configuration, but the rich-burn emission limit would still apply to the converted engine. See the staff response to MECA's comment under §117.207(f), following, concerning emission limits for lean-burn engines.

MECA commented that major new sources in ozone nonattainment areas should be subject to case-by-case LAER evaluation rather than to RACT rules for existing sources, and recommended that §117.206, relating to Emission Specifications for New, Rich-Burn Engines, be deleted. MECA further commented that the 2.0 g NO_x/hp-hr limit for new rich-burn engines in §117.206(a) is too high for LAER. Star commented that the block one-hour average in §117.206(a) should be changed to a less restrictive 24-rolling average

Section 117 206 was included in the original rule proposal because of an apparent conflict between the 150 hp applicability limit proposed for existing RACT sources and the 500 hp applicability limit for new sources provided by TACB Standard Exemption 6. The intent was to close the loophole for new engines rated less than 500 hp which, if exempted under Standard Exemption 6, would have had less-stringent control requirements than existing engines under the RACT rule The staff believes that new rich-burn engines should be subject to applicable new source review requirements of TACB Regulation VI, including LAER review, for ozone nonattainment areas It will be more appropriate to address these exemption applicability issues in a future revision of Standard Exemption 6, especially since other concerns about the exemption have been raised which could require revision Therefore, TACB is withdrawing the proposed §117.206 at this time.

It is important to note that increasing the compliance averaging period beyond one hour necessitates the use of CEMS as a practical matter for enforcement purposes. Even though an emission limit and averaging time are no longer proposed for new engines in the rule, other rule sections specify a one-hour block average for certain existing sources such as industrial boilers and heaters for which CEMS is not required.

MECA commented that §117.206(b) provides a total exemption for new or modified lean-burn engines, and emphasized the need for a reasonable emission limit for lean-burn engines As originally proposed, §117.206(b) would have exempted only emergency standby or peaking engines operating less than 200 hours per year, referenced in §117.203(b)(6), and stationary internal combustion engines rated less than 150 hp, referenced in §117.203(b)(8). Exemption of all new lean-burn engines was never proposed in this section or elsewhere in the rule. The potential applicability of nonattainment new source review provisions of Regulation VI was specifically referenced in §117.206(d) . See the previous response to MECA's comment concerning LAER evaluation and new source review, and MECA's comment under §117 207(f) concerning establishing reasonable emission limits for lean-burn engines.

Section 117.207-Alternative Plant-Wide Emissions Specifications. MECA and Star expressed support for §117.207. Star stated that subsection (f) should be as flexible as possible by including controlled individual units versus the proposed inclusion of the entire class of units. MECA suggested that a lower emission limit for lean-burn engines should be instituted and have this emission specification placed in §117.205(f). The staff appreciates the support. See the response to the comment in §117.207 for further discussion on the inclusion of single, exempted units in §117.207(f). The staff is not able to recommend a more stringent limit for the lean-burn engines at this time; however, it will be considered in future rulemaking.

EPA expressed support of the concept of averaging as specified in §117. 207, but stated, "the EPA must be assured that RACT equivalent emission reductions will occur." EPA further stated that the use of maximum rated capacity rather than actual heat input in calculating equivalency between the averaging group and the plant-wide emission limit does not meet EPA's methodology.

The averaging allowed under §117.207(a)-(h) is equivalent to RACT. Equivalency is demonstrated by the application of RACT emission limits to each affected source and using performance testing and emissions monitoring to verify compliance. The staff has deleted §117.207(i) at the request of EPA to ensure equivalency. See the response to the comment by EPA in §117.207.

Since TACB was trying to write a NO_x RACT rule in the specified timeframe mandated by Congress in the 1990 FCAA Amendments, and EPA guidance was not available on the use of maximum rated capacities at the this time, the staff believes that the emission limits combined with the averaging provisions constitutes RACT for the affected sources. This is the third condition in EPA's comment in which EPA has stated that they would accept the use of maximum rated capacities.

Champion recommended that TACB consider, on a case-by-case basis, credits for NO_x reductions which will be achieved one year after the May 1995 compliance date for RACT. The staff does not agree with the concept of allowing prospective emission reductions to be used for compliance purposes. However, §117.540 sets forth a mechanism for phased RACT and §117.221 allows for alternative RACT on a case-by-case basis.

GHASP opposed the concept of alternative plant-wide emission options. "In particular we object to the weakening of this weak proposal that when a unit in a system-wide emission system was found in violation that all units in that system would then be in violation. By taking away this enforcement hammer TACB ensures that industry will not operate as carefully to prevent exceedences (sic) and violations of these rules." GHASP's particular objection is pertinent to the system-wide emission cap approach which was included in a June draft version of the rule for electric utilities only and was not included in the actual proposed rule version. The rule currently relies on a plant-wide emission average with individual emission limits. Individual limits are enforced individually, unlike the group limit of a facility cap in which compliance can be determined only if all units simultaneously report emissions. The staff supports the comment as it applies to facility caps. The plant-wide emission average with individual limits has been implemented successfully by the SCAQMD in the State of California in SCAQMD's 1109 rule.

TMOGA and Mobil requested that flexibility be provided in §117.207 through a combination of parametric monitoring and CEMS. The flexibility would come by way of one facility site-wide enforceable limit versus individual unit emission limits. Compliance with the single, site-wide emission limit would come through monitoring each of the affected sources with an operating parameter monitoring system (OPMS) or CEMS. The staff has eliminated the operating parameter monitoring requirements in §117.213(a), primarily due to the staff's concern about the accuracy of the data from the parametric monitoring system. See the response to the comment by TCC in §117.213. Industry has rejected the staff's attempts to require the installation of CEMS to monitor all units affected by emission limits. A single, plant-wide emission limit plan would not be enforceable without accurate monitoring of each affected unit. The staff is evaluating a facility cap concept for future rulemaking that does address a single, plant-wide emission limit. See the response to the comment by TCC in §117.207, as well

TCC, TMOGA, Amoco Chem, Amoco Oil, Chevron, Dow, Exxon Chem, Exxon, Mobil, Phillips, and Shell suggested a "facility cap" concept on a pound per hour basis. The staff is presently working on this concept and intends to consider its development in a second round of rulemaking in the summer of 1993. The facility cap is an alternate to the plant-wide emission limit as proposed in §117.207, and is perceived to be beneficial in making NO_x reductions. There are several factors which need to be addressed to the satisfaction of EPA and TACB in proposing such a concept. The need to demonstrate equivalent reductions and the use of monitoring to demonstrate compliance are two key issues.

TCC and Texaco believe that the rule calls for enforceable limits on each individual unit. TCC suggested that the rule allow for a plant cap limit with appropriate demonstrations. The proposed rule uses individual unit emission limits in both §117.205 and §117.207. The staff does not agree with Texaco's suggestion that the rule requires dual compliance with both of these sections. The first sentence of §117.207, "Alternative Plant-Wide Emission Specifications," clearly states that this section may be used to achieve compliance with §117.205. Under this section, the plantwide emission limit is calculated using the individual emission limits in §117 205. The individual emission limits of §117.205 are used with units' maximum rated capacities to determine the calculated plant-wide emission limit; individual enforceable limits are then assigned by the affected person to each unit By enforcing the individual limits set by the affected person, an alternate means of compliance with §117.205 is achieved. The concept of a facility cap is being considered for future rulemaking.

Oxy requested that the system-wide limit available for the electric utilities should also apply to the industrial units. The staff has recognized the benefit of plant-wide and system-wide averaging to the affected community. The staff believes that since the industrial sector has a wider variety of NO_x sources than do the electric utilities, that NO_x RACT trading would be the best method to allow industrial system-wide averaging. A detailed trading program will be considered in future rulemaking. The staff believes that this is the appropriate format to address the complexities of averaging emissions from a multitude of sources and sites. The primary concern is demonstrating equivalent reductions among the affected units. The electric utilities are required to install CEMS on their units through Title IV of the 1990 FCAA Amendments, which simplifies the demonstration of compliance with a system-wide limit. The affected industrial sources are not required to install CEMS on all units, thereby complicating the demonstration of equivalency.

TCC, TMOGA, Chevron, Exxon Chem, Exxon, Mobil, Oxy, Phillips, Star, and Champion stated that the requirement to include an entire class of exempted equipment to be controlled if any unit is to be included in the plant-wide averaging specification allowed in §117.207(f) is an extreme requirement Chevron said, "The requirement for the class of units is arbitrary and capricious and serves no value to the environment, but unnecessarily reduces flexibility and adds cost " The use of the option to include exempt classes in plant-wide averaging is entirely up to the affected facility. The rule is structured to ensure that all controlled sources of a particular class of equipment are included into plant-wide averaging, and not just the clean, uncontrolled, exempted units which would help toward the plant-wide average without actually reducing emissions. It must also be noted that the staff believes that many of these exempted classes of equipment will require individual emission limits in the future. Enron recommended that duct burners be included as an opt-in class of exempted units in §117.207(f), since they may reduce NO_x emissions

The staff disagrees that duct burners will reduce NO_x emissions. A presentation by Jon Backlund of COEN (a manufacturer of duct burners) at the February 10, 1993, Council of Industrial Boiler Owners conference reported that reburning occurs at high turbine NO_x emissions (e.g , 250 ppmv NO_x), but that no reburning is observed at low turbine NO_x emissions.

The staff recognizes the need to establish a RACT limit for duct burners in future rulemaking to comply with EPA's interpretation of the FCAA Amendments However, most duct burners, which have been permitted in the last ten years and use LNB, probably emit at a level consistent with RACT In developing RACT for duct burners, the staff believes the duct burner limit should either recognize existing actual emissions as RACT or perhaps set an emission limit which would require any high emitters to install controls such as LNB. The latter option should be used only if there are actual units which could reduce emissions by retrofitting burners

The staff is concerned that the result of the TACB establishing a duct burner limit may be that no additional duct burner controls would be required, and, just as important, that higher gas turbine emissions would be allowed as a consequence of plant-wide averaging. The staff does not believe this approach is consistent with RACT.

MECA commented that in §117.207(f), lean-burn engine emission controls should be required rather than be optional in a plantwide emission limit. The staff recognizes that lean-burn engines will require NO_x RACT rules in order to comply with EPA's FCAA Amendments interpretation of applying NO_x RACT to all major sources. Lean-burn engines were deleted from the June 1992 draft NO_x RACT rule to facilitate early rule adoption. In doing so, the staff considered that establishing RACT is more difficult, emissions are more variable, and control options are more complicated for lean-burn than for rich-burn engines. Engine rebuilds and selective catalytic converters are two effective control techniques for lean-burns, but the costs may be an order of magnitude higher than rich-burn NSCR. Lean-burn engine parameter adjustments are not as effective in reducing emissions, but may allow additional controls to be added later without violating the principle of "buildable steps." The population of lean-burns is older than that of the rich-burns. For instance, Amoco operates 16 1940's vintage lean-burn engines at a compressor station. Rebuilding such old engines to be low emitters may not be practicable or cost-effective. Other possibilities, such as selective catalytic reduction (SCR) or conversion to electric drive, may be very expensive and require long-range economic planning. The staff sees a significant potential cost-effectiveness benefit in promoting more flexible emission trading schemes before requiring such sources to greatly reduce their emissions.

TMOGA, Exxon Chem, Exxon, Mobil, Nalco FuelTech (Nalco), and Chevron disagreed with the emission limit for CO boilers which was proposed in §117. 207(f)(1). Amoco Oil requested that §117.207(f)(1) be deleted entirely and is willing to participate in a study to evaluate NO_x control technologies.

The staff agrees that an emission limit of 0.10 lb NO_x/MMBtu may be BACT for refinery CO boilers However, it must be noted that SCAQMD has a 0. 03 lb NO_x/MMBtu standard for refinery boilers and process heaters in SCAQMD's Rule 1109. Suggestions for emission limits ranging from 0.30 lb NO_x/MMBtu (Exxon Chem and Exxon) to 1.0 lb NO_x/MMBtu (Mobil and Nalco) were made, as well as deleting §117.207(f)(1) entirely (Amoco Oil). The staff believes that a joint study between the refiners and the TACB to evaluate the NO_x emissions from FCCU CO boilers is worthwhile. However, the staff believes that there is presently enough information to recommend a new limit of a 50% reduction of NO_x across the CO boiler, as a unit, to encourage use of the inclusion of CO boilers as an entire class in the alternative plant-wide emission limit. This approach is a direct result of the wide range of actual NO_x emissions from the various types of CO boilers currently in use in the ozone nonattainment areas. The assignment of one emission limit in a lb NO_x/MMBtu format may be too restrictive for some units and too lenient for others. A percent reduction will allow all CO boilers the same opportunity for reductions.

The following items have been added or explained to facilitate the use of a percent reduction of a CO boiler into §117.207(f)(1). The staff has revised the term "heat input" as it relates specifically to a CO boiler be revised. This revision will allow the calculation of the heat input term in the denominator of the lb/MMBtu term which is used in determining the emission rate. The conversion from ppmv of NO_x to lb NO_x/MMBtu will require the knowledge of the FCCU regenerator off-gas volumetric flowrate and the CO boiler exhaust volumetric flowrate at different operating conditions (for example, at varying CO boiler auxiliary firing rates and regenerator flowrates). The NO_x concentration in ppmv can then be converted into a mass flowrate using these volumetric flowrates. CO boilers which are opted into §117.207(f)(1) will have the calculations for the conversion from NO_x concentration in ppmv to lb NO_x/MMBtu submitted to the Executive Director for approval as part of the initial control plan. The staff has clarified the requirement to submit calculations for CO boilers in §117.209(7).

Texaco commented that the language in §117.207(f)(3) which references using the emission specifications in §117.205(a) needs clarification as to the heat input size. The staff agrees and the wording in §117.207(f)(3) has been changed to show that the emission limits of §117.205(a)(3)(A)-(E) are to be used for the applicable type of unit.

TCC, TMOGA, Exxon Chem, and Exxon suggested that definition of mass emission loading be incorporated into §117.207(g). The staff does not believe that the suggested definition would clarify the proposed rule. See the response to TCC's comment in §117.10.

Chevron expressed support for using 1990 as the baseline year for reductions, using shutdown units in calculating the plant-wide emission limit. Due to comments by EPA, §117.207(i), regarding the use of shutdown credits has been deleted. See the response to the comment made by EPA in §117.207.

EPA expressed concern over the use of shutdown or curtailments in an averaging plan which regulates emission rates, not total source emissions. EPA stated, "The EPA's policy, however, is that shutdown units cannot be used to meet a RACT averaging plan. RACT assumes that control technology is installed on each applicable unit. Since a source would not be required to install RACT on a unit that is shutdown, shutdowns cannot be included in a RACT averaging group." Based on EPA's comments, subsection (i) has been deleted from §117. 207 to eliminate including shutdown equipment in the plant-wide emission limit averaging option. EPA noted, however, that it would allow shutdowns in a facility cap option. EPA stated, "If, however, a NO_x emissions cap (i.e., mass NO_x emissions per unit time basis) is established for a group of units at a facility, a permanent shutdown may be credited towards compliance with the emission cap. Since total emissions are limited (at a RACT equivalent level), any decreases in production, including shutdowns, could be creditable towards compliance with the emissions cap." The concept of a facility cap will allow the inclusion of retired units since their actual emissions will be considered.

TCC, TMOGA, Amoco Oil, Chevron, Exxon Chem, Exxon, Mobil, Oxy, and Phillips objected to the requirement that shutdown units which are to be included in the plant-wide emission section must be permanently disabled. They stated that NO_x controls could be installed before the unit is restarted, or that the unit could undergo a BACT review through a permit application, in case of a disaster or other circumstance which would warrant bringing the unit back into service. Section 117.207(i), regarding the use of shutdown credits has been deleted. If the facility cap concept were to be adopted in future rulemaking, shutdown units would not have to be rendered permanently inoperable. As a result, this approach should satisfy TCC, TMOGA, Amoco Oil, Chevron, Exxon Chem, Exxon, Mobil, Oxy, and Phillips.

Texaco asked that TACB give guidance on certifying a unit's 1990 operational level and maximum rated capacity. Since the 1990 operational level will not appear in the rule due to the recommended removal by EPA of the subsection containing this reference, guidance will not be required. The maximum rated capacity is defined in §117.10.

Section 117.208–Operating Requirements. Oxy suggested that TACB offer the option of meeting either emission limits or operating requirements, but not both. The requirements in §117.208 specify that the operation of the affected equipment must be done in compliance with the emission limits of §117.205 and with the limits submitted by the affected persons in the compliance plan required in §117.215 of the proposed rule. The rule also requires that all equipment affected by the emission limits in §117.205 comply with basic operational requirements. The staff, therefore, believes that this section is beneficial in reducing NO_x emissions in conjunction with the emission limit specifications. The requirements of §117. 208 have been retained for the affected equipment.

TCC, TMOGA, Exxon Chem, Exxon, and Mobil requested that §117.208(a) defer to the General Rules in referencing the major upset and maintenance periods as specified in §117.208(a). The commenters also requested that the section include a reference to the emission limitations in §117.207, as well as the reference to §117.205. The staff agrees and has reworded §117.208(a) to defer to the major upset and maintenance provisions identified in the General Rules in 101.6, 101.7, and 101.11. See the response to TCC's comment in §117. 203. The staff also agrees with the comment regarding a reference to the emission limitations in §117.205 and §117.207 and has added appropriate wording.

Enron suggested that the staff revise §117.208(a) to include all start-ups and shutdowns, both hot and cold. The staff will further consider start-up and shutdown definitions in future rulemaking. See the previous response by TCC in this section.

Texaco suggested that §117.208(a) be moved to §117.205(f) for clarification. Subsection (f) in §117.205 exempts specific types of units from the emission limits in §117.205. Subsection (a) in §117.208 states that the units subject to the emission limits in §117.205 comply with those emission limits. The basis for §117.208 is to require the affected equipment to be operated in a manner such that the units comply with the emission limits in §117.205 and with the limits submitted by the affected persons in the compliance plan in §117.215 of the proposed rule. This section is particularly important for units without CEMS installed to ensure continuous emissions reductions. Section 117.208 also requires that all equipment affected by the emission limits in §117.205 comply with basic operational requirements. Section §117.208 remains as it was proposed, other than the recommended revisions to reference major upsets, maintenance, and §117.207.

TCC, TMOGA, Exxon Chem, and Mobil requested that words be added to §117. 208(b) to reflect a facility cap. As mentioned earlier in the response to TCC's comment in §117.207, the facility cap concept may be considered for future rulemaking.

TCC and Exxon Chem requested that the operating requirements in paragraphs (1)-(6) in §117.208(c) be deleted. TCC stated, "In a number of situations, these proposed operating restrictions would result in unnecessary retrofit costs on older units, with little or no benefit in terms of real NO_x reductions." The staff disagrees that the requirements should be deleted. The purpose is to require equipment to be operated in such a manner as to reduce NO_x emissions over the entire operating range. These requirements will ensure that NO_x reductions are achieved, particularly for units without CEMS installed. The staff believes that they are beneficial and necessary, without being costly or burdensome.

TCC, TMOGA, Exxon Chem, and suggested that the phrase "but are not limited to," in §117.208(c) be deleted. The reason is that the phrase could promote regulatory uncertainty because of its ambiguity. The staff agrees with the request and has deleted the phrase from §117.208(c).

TMOGA and Mobil recommended that the operating requirements for FGR in §117.208(c)(2) and (3) be eliminated because the retrofit ductwork may not allow accurate metering of the FGR rate. Paragraph (2) requires that the proportional design rate of FGR be maintained, consistent with combustion stability, over the operating range. This requirement can be implemented with the use of FGR curves, which should be based on vendor data for the FGR system. Metering may be required initially to determine the curves, but other means would be available to provide the information to graphically represent the FGR curves. Paragraph (3) requires that any unit utilizing induced draft FGR be operated such that the operation of FGR over the operating range is not restricted by artificial means. This requirement has nothing to do with metering of the FGR rate, only that no artificial means be used to restrict the FGR operation (such as closing dampers) which would minimize NO_x reductions. These requirements are beneficial and necessary, and have been retained as proposed.

ATINGP commented that in §117 208(c)(6), air-fuel ratio (AFR) controllers may be duplicate controls unnecessary for NSCR to meet emission limits. Section 117.208 requires any engine using NSCR as a control method to be equipped with an automatic AFR controller. There is a very narrow band of AFR for which NSCR works, and an AFR controller is necessary for NSCR to operate properly.

TCC commented that §117.208(c)(7), which specifies procedures for periodic measurement of NO_x and CO emissions after certain engine maintenance operations, should be moved to §117.213, relating to Continuous Demonstration of Compliance. Routine operation of internal combustion engines, including periodic engine maintenance, O_2 sensor replacement, and catalyst cleaning or replacement, causes changes in engine performance which are likely to increase NO_x and CO emissions. Performing regular NO_x and CO measurements at least quarterly will improve the chances of detecting conditions of excessive emissions which otherwise might go undetected between stack tests conducted biennially or every 15,000 operating hours. The staff believes that these are valid operating requirements for internal combustion engines. The emissions measured by portable analyzers are not used directly for determining compliance, and the staff does not see the benefit gained from moving the requirements to §117.213.

Section 117.209-Initial Control Plan Procedures. Regarding §117. 209, Initial Control Plan Procedures, Oxy and Phillips suggested that submittal of initial compliance plans is unnecessary and should be eliminated from the rule. The initial compliance plan required by §117.209 provides a demonstration that companies are making their best effort to comply with the rule requirements by May 31, 1995. The initial plan as required by the rule is an interactive planning tool, not an enforcement tool against specific future allowable emission rates. Compliance with the individual emission limits of §117.205 or the company-assigned enforceable emission limits of §117.207 must be established in the final compliance plan.

The information provided allows the staff to assist companies in creating an approvable final compliance plan for a complicated rule. Also, the information provided will identify issues which may be resolved in a straightforward manner prior to the final compliance date, such as identification of approvable alternate fuel gas analysis methods. The information provided will be functionally the most accurate major point source NO_x emissions inventory yet obtained for the areas, which will benefit development of technically sound ozone reduction policy.

Finally, the plans are needed by the TACB to develop an objective evaluation of the need for a phased RACT schedule. Industry could have a strong incentive to provide this information. If the TACB does not receive information on affected units as requested, the TACB would presume that the rule requirements for those affected units have no impact on meeting the May 31, 1995 implementation date and would not be able to consider them in evaluating the need for any phased RACT by rulemaking under §117.541(b).

Shell suggested that alternative methods of continuous monitoring be submitted with the initial control plan and be subject to the Executive Director's approval, with an appeal to the Board if necessary. Star suggested appointment of an independent arbitrator to appeal the Executive Director's approval of an initial control plan.

The staff disagrees with these suggestions and does not consider the proposed requirement to install CEMS an item for appeal. The staff has negotiated over a long period with industry to retain the proposed requirement for NO_x CEMS on the largest NO_x emitters in the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas. Existing programs such as NSPS, Subpart Db, and TACB Permits practice require NO_x CEMS on new boilers rated more than 100 MMBtu/hr heat input, as compared to existing boilers rated more than 250 MMBtu/hr heat input in the proposed rule. The NSPS program was developed well before the shift in emphasis toward NO_x control in ozone attainment strategy. In response to Star's suggestion to appoint an independent arbitrator to consider these appeals, the staff notes that the TACB does not have the authority to delegate its decision making powers in this way.

The emissions variability from actually monitored units the staff has encountered while evaluating and developing NO_x emission limits for both utility and industrial sources has strengthened the belief that sound NO_x emissions reductions programs are not possible without systematic emissions monitoring. As discussed in responses in §117.213, the staff has recommended specific changes to reduce the costs of implementing the monitoring provisions while retaining the fundamental ability to measure the emissions.

Texaco suggested that the TACB provide guidance on an acceptable format for presenting the information required in the Initial Control Plan. The staff intends to develop this guidance. Suggested uniform reporting formats will assist the TACB in evaluating the information presented.

Texaco stated that a company should have an opportunity to revise the initial control plan required in §117.209. Texaco suggested that a reference to the control plan revision ability of §117.217 be added in §117.209. The wording in §117.209 has been revised in the same manner as §117.109. See the response to HL&P's comment in §117.109 and HL&P's comment in §117.117, relating to Revision of Control Plan.

TCC, Amoco Chem, Amoco Oil, Exxon Chem, and Baker & Botts (B&B) suggested that the TACB clarify that the initial control plan is not an enforceable document, but that it is merely a planning document.

The staff agrees with this comment to the extent that the initial control plan is intended to be a planning document for use by the owner or operator and the TACB. The selection of assigned emission rates in the initial control plan will not be an enforceable issue. The submission of the initial control plan and the seven requirements contained in this section are enforceable issues; the TACB expects the affected persons to comply by submitting a complete initial control plan.

Amoco Chem, Amoco Oil, Exxon Chem, B&B, and TCC requested that the requirement for TACB Executive Director approval of the initial control plan be deleted. B&B also suggested a provision to allow sources that cannot meet the May 31, 1995 compliance date to be able to request approval of a later compliance date in the initial control plan and to list specific control plan milestones as part of that request.

The staff has retained the proposed rule language concerning Executive Director approval in the rule. The approval by the Executive Director of the initial control plan is for the purpose of ensuring that a NO_x reduction control plan is being implemented by each affected person. The May 31, 1995 final compliance date will be reevaluated one year after the adoption of the proposed rule, as specified in §117.540(b). Section 117.540(a) already allows an affected person to apply for a change in the final compliance date. The staff disagrees with the comment to incorporate a provision to allow a request for a compliance date later than May 31, 1995, which would include specific schedule milestones. The staff recommends not allowing a request for a final compliance date extension in §117.209.

TCC, TMOGA, Exxon Chem, Exxon, Mobil, Oxy, and Phillips requested that the listing threshold in §117.209(1) for combustion sources with a maximum rated capacity of greater than 5.0 MMBtu/hr heat input be raised to 40.0 MMBtu/hr heat input. The staff disagrees with this request. Section 117.201 states that the rule is applicable to industrial boilers and process heaters with a maximum rated capacity of 40.0 MMBtu/hr heat input or greater. The purpose of listing all combustion sources greater than 5.0 MMBtu/hr heat input is to gather information on all potential major point sources of NO_x emissions. However, the units greater than 5.0 MMBtu/hr heat input and less than 40.0 MMBtu/hr heat input have no other requirements in the proposed rule. The staff does not believe that this listing requirement is sufficient reason to state that these units have rules applicable to them.

TCC and Exxon Chem objected to the wording of §117.209(1) and suggested that the phrase "anticipated annual heat input" be deleted because it adds no value to the initial control plan. The staff sees benefits of requiring both the maximum rated capacity and the anticipated annual heat input of the affected industrial boilers and heaters. The anticipated annual heat input data is generally available, can readily be included in the initial control plan, and it is a number which will be required in setting a facility cap, which is an option to be considered for future rulemaking. As a simplification, the staff recommends revising the requirement of listing the anticipated annual heat input of each unit to requiring the listing of the anticipated annual capacity factor of each unit in the proposed rule. The annual capacity factor provides the same information as the anticipated annual heat input, except that it is expressed as a percentage.

TMOGA and Mobil stated that the requirement in §117.209(1) to list the facility identification number and emission point number for each piece of equipment identified in §117.209(1) is nonproductive and requires significant additional work. The facility identification number and emission point numbers are integral to the TACB in identifying equipment. Listing these identifiers will assist the TACB staff in studying the initial control plans. The facility identification number and emission point number identifiers are the key to relating the equipment at the facility to emission inventory data, permits, and other relevant information. These identifiers should be readily available to both the staff and industry, and should be included in the initial control plan because of their usefulness.

TCC and Exxon Chem requested that the word "anticipated" be added before the phrase "construction schedule" in §117.209(5).

The staff agrees with this comment and has added the word "anticipated" before the phrase "construction schedule" in §117.209(5).

EPA requested that a more specific construction schedule be submitted in the initial control plan as in §117.109(c)(6) for the utilities.

The staff believes that the requirement to list anticipated, specific construction dates in §117.209(5) as in §117.109(c)(6) would be worthwhile. The specific dates would allow the TACB to better evaluate the final compliance date and the need for "phased RACT" by future rulemaking. The staff is aware that the dates are subject to change, due to scheduling difficulties. The staff's intention is that these dates will not be enforceable, but they should be submitted in the initial control plan. However, because of the way the *Texas Register* interprets APTRA to require public notice in the *Texas Register* for any new requirements, the staff cannot recommend requiring additional, specific construction dates. Therefore, the staff has retained the schedule required in §117.209(5), as proposed.

TCC, TMOGA, Exxon Chem, and Exxon suggested that the words "retired or decommissioned" in §117.209(6) be replaced with "shutdown and rendered inoperable."

The staff believes that, on the basis of clarity and consistency, the suggested words be added to the phrase "retired or decommissioned." The staff recommends changing the wording to include the phrase "shutdown and rendered inoperable."

TCC, TMOGA, and Exxon Chem requested that the phrase "mass rate" be replaced with the phrase "emission rate" in §117.209(7) and the reference to the plant-wide emission limit be deleted. This would facilitate the inclusion of a facility cap into the proposed rule. TCC, TMOGA, and Exxon Chem requested a new paragraph to be included in §117.209 to request that the basis for compliance with the plant-wide emission limit under the facility cap be included in the initial control plan.

See the response to TCC's comment in §117.207 pertaining to facility caps. These comments will be addressed during the consideration of a facility cap in future rulemaking.

EPA requested that §117.209(7) also require a calculation of the plant-wide emission limit and a preliminary analysis of unitspecific emission limits for each affected unit.

The intent of §117.209(7) is to require the basis for the calculations which should include the plant-wide emission calculations and the preliminary assignment of the individual emission rates for the affected units. The staff believes that this explanation will document the intent of the rule language, but recommends clarification that these calculations include those pertinent to CO boilers in §117.209(7). See the response to TMOGA's comment in §117. 207 for clarification of the requirements for calculations for CO boilers.

Section 117.211-Initial Demonstration of Compliance. Regarding §117.211, Initial Demonstration of Compliance, Star and Chevron requested an allowance in §117.211 for difficulty in retrofitting older units with sampling ports and platforms in §117.211.

The staff has been made aware by industry that the sampling ports and platforms are not always available. Section 101.9, concerning Sampling Ports, requires the installation of platforms and sampling ports for use by the TACB to determine the nature and quantity of emissions. The staff recognizes that there may be difficulty in providing these arrangements, and is currently working to assist industry in facilitating the sampling. One approach to economic reasonableness in installing platforms is that sampling platforms should first be installed on units which are being modified with NO_x control equipment during turnarounds or plant outages. The units which are not being modified should have less priority on sampling platform installation.

GHASP requested elimination of the phrase "or as near thereto as practicable" from §117.211(a). This comment is in reference to testing at the maximum operating capacity of a unit. The staff's position is that a unit may not always be able to test at its maximum rated capacity due to safety, operational, or other concerns. The phrase "or as near thereto as practicable" takes these factors into consideration. The staff recommends retaining the wording as proposed.

Amoco Chem, Amoco Oil, Phillips, and Texaco suggested that the TACB allow testing of one unit to suffice for testing of all other identical units for the initial demonstration of compliance. The variability of such tests causes concern for the staff. Phillips stated, "Many of the heaters at this facility have identical designs and firing rates (i.e., an ethylene unit has five identical furnaces that are all fired at the same rate). One stack test would suffice for identical furnaces." In a recent permit, C-18816, Phillips performance tested six ethylene cracking furnaces in Unit 33. Furnace Number 2 burns butane, Furnace Number 5 burns propane and ethane, and Furnace Numbers 1, 3, 4, and 6 burn propane. The furnaces are identical in all other respects, yet the testing showed a range of NO_x emissions from 0.053 lb NO_x/MMBtu for Furnace Number 6 to 0.078 lb NO_x/MMBtu for Furnace Number 2. This variability is large enough to warrant testing each unit. Since a TACB representative will not be required to be present during testing, the staff also believes that all units should be tested. This requirement would minimize the chance of submitting only the best test results for one unit out of a group of identical equipment.

Amoco Chem said, in their discussion of this topic, "TACB has stated that these initial stack tests are for planning purposes, not a strict demonstration of compliance." The staff wants to clarify this statement by stating that testing results for affected equipment will be enforceable; the testing results for the equipment exempted from emission specifications will not be enforceable. The testing results for the affected equipment must be enforceable since the results will be used to verify compliance with the individual limits in the plant-wide emission limit control plan. Further, if exempted equipment is opted into the plant-wide emission limit control plan, the testing results from that equipment will be enforceable, as well.

Amoco Oil requested that the testing requirements in §117.211(c) for FCCU units be deleted. The staff's position is that since the FCCU's are major sources of NO_x emissions, the need for testing to determine the quantity of emissions is reasonable. Amoco Oil's recommendation for deletion of testing of FCCU's goes against the statement made by them when they state, "there has been very little emphasis placed on gathering data to properly evaluate the proper RACT levels from FCCU CO boilers." Without testing data, proper FCCU emission limits can not be determined. The concern over emission limits for FCCU's has prompted the staff to explore and recommend an optional percent reduction type limit for CO boilers used to opt into §117.207, in lieu of a numerical emission limit. See the response to TMOGA's comment in §117.207 concerning CO boiler emission limits.

TCC, TMOGA, Amoco Oil, and Exxon Chem requested that the testing requirement for gas turbine HRSG's be deleted. Amoco Oil stated, "Such emissions represent less than 15% of the NO_x emissions from large gas turbines."

Large gas turbines and accompanying HRSG's can be quite large sources of NO_x emissions. Due to the potential of HRSG's being major sources, the staff believes that the HRSG testing requirement is reasonable and has retained it in the rule.

TCC, TMOGA, Amoco Oil, Exxon Chem, and Exxon requested a delay in the installation of CEMS for unmodified units until the final compliance date.

The staff agrees with the request, and has extended the compliance date for CEMS installation for unmodified units from April 1, 1994 to May 31, 1995. The process of budgeting, contracting, installation, and certification testing for CEMS will commence after rule adoption. The staff believes that the proposed schedule, which requires these steps to occur within 11 months of rule adoption, may be difficult to implement in every case. The resources of many CEMS manufacturers and service contractors will be in high demand between May 1993 and early 1995 because FCAA Title IV requires 2100 utility NO_x CEMS to be installed and operating by January 1, 1995. One outcome of maintaining the proposed schedule could be higher costs and lower quality CEMS. Although the FCAA Amendments require that RACT measures be implemented "as expeditiously as practicable but no later than May 31, 1995," the Title IV demand may make the 11month schedule more difficult.

TMOGA, Chevron, Exxon, Mobil, Oxy, Phillips, and Star requested that all units greater than 40.0 MMBtu/hr heat input and less than 100.0 MMBtu/hr heat input and all unmodified units be allowed to test using portable analyzers. Oxy, Phillips, and Star stated that the TACB should allow the use of portable monitoring equipment for equipment testing in §117.211. The staff believes that the use of portable test equipment, such as the commenters have suggested, is valid for those units which are exempt from emission limits and has changed the rule to allow such testing. Due to the required enforceability of testing affected units, the staff believes that the affected units will require certified stack testing to be performed. See the earlier responses to comments by TCC and Amoco Chem in §117.211 for related discussions.

TMOGA and Mobil requested that all process heaters greater than 100.0 MMBtu/hr heat input and less than 200.0 MMBtu/hr heat input and all industrial boilers greater than 100.0 MMBtu/hr heat input and less than 250.0 MMBtu/hr heat input be tested by a certified tester.

The staff agrees that the test methods for establishing rule compliance must be "certified" EPA reference methods. Currently, the TACB does not have a certification program for testers and the proposed rule reflects this point.

TMOGA and Mobil requested that all process heaters greater than 200.0 MMBtu/hr heat input and all industrial boilers greater than 250.0 MMBtu/hr heat input have CEMS certification testing by the final compliance date and that portable testing results be allowed for compliance requirements prior to the final CEMS certification testing. The staff agrees with this request and has added rule language in §117.213 which allows for a 30-day compliance test utilizing CEMS. The staff has used the CEMS testing requirements of 40 CFR 60.46b(e) as guidance. Section 117.211 was proposed with 40 CFR 60.46b(e) as a model compliance method for CEMS certification. See the earlier response to TCC's comment in §117.211 for a related discussion.

TMOGA and Mobil requested that TACB allow flexibility in test procedures, for example in the sample port size requirements, and using the "F" factor method to calculate the flue gas mass flow rate. The staff is considering the use of such ideas and methods, as long as the accuracy of the test data is not compromised. The staff expects to give procedural guidance on this and other testing issues.

TMOGA and Mobil requested that the TACB allow for new, equivalent EPA test methods in §117.211, should any be adopted by EPA. The staff agrees with the request and the appropriate changes have been made to §117.211(f).

TCC, Amoco Chem, Amoco Oil, Exxon Chem, and Chevron requested that the TACB allow unmodified units to test these units using TCC test protocols or best available methods, such as portable analyzers. TCC submitted test protocols in Attachment II in their comments which outline the testing procedures. The TACB is currently evaluating these protocols to determine their usefulness. The staff expects to give procedural guidance on this and other testing issues.

TMOGA, Exxon Chem, and Mobil requested that the labeling requirements in §117.211(g) be deleted. The commenters state that equipment labeling will provide no benefit to the TACB. Exxon Chem expressed concern about the clear identification of equipment to contractors working in the plant. The staff believed that the labeling of equipment would benefit inspectors from the TACB and local programs by aiding them in associating individual emission sources with applicable rules, permit allowables, operating restrictions, and control requirements. However, any possible benefits were never fully explored, and the staff has deleted labeling requirements.

Section 117.213–Continuous Demonstration of Compliance. TCC and Exxon Chem requested that all the operating parameter monitoring requirements be deleted from §117.213(a). Amoco Chem and Amoco Oil suggested that only operating parameter monitoring requirements for steam/water injected gas turbines which are larger than 30 MW would be acceptable. The staff believes that the ability of operating parameter monitoring systems to estimate emissions is not yet fully proven, especially for industrial boilers and process heaters. The factors that affect the generation of NO_x are not always easy to monitor, such as residence time in the flame envelope, flame temperature, and the air to fuel ratio at the flame envelope interface. These factors make it difficult to monitor NO_x emissions by way of equipment operating parameters.

The staff realizes that the additional time required for performance testing to optimize the predictive ability of an operating parameter monitoring system would be a burden on industry to meet the final compliance date.

The staff is also awaiting EPA guidance on the enhanced monitoring program as a part of Title V of the 1990 FCAA Amendments. Evaluation of enhanced monitoring is expected to be a case-bycase permit review by the Permits Program beginning in 1996. The staff is anticipating working with industry to develop policies on operating parameter monitoring requirements. Due to these concerns, the staff believes that the requirement of implementing operating parameter monitoring requirements for the industrial boilers and process heaters listed in this subsection is not feasible now. However, the staff believes that the requirements of installing O_2 monitors and totalizing fuel flow meters are still beneficial. Also, these instruments are needed for determining emission rates if CEMS are subsequently required. The staff has deleted the requirement to install, calibrate, maintain, and operate an OPMS in §117.213(a), but, has retained the requirements to install O_2 analyzers and totalizing fuel flow meters.

Champion objected to the requirement in §117.213(a) for the installation of an O_2 analyzer. Champion stated, "It seems inappropriate to require as a minimum an O_2 analyzer and fuel totalizer just for the purpose of collecting data of little benefit." The staff understands that an O_2 monitor can be influenced by air leakage which may prevent a good correlation with NO_x emissions. For units equipped with CEMS, an O_2 analyzer is a definite requirement. The staff will allow industry flexibility in locating and timing the installation of the O_2 analyzers in meeting the requirements of §117.213(a). The staff believes that the data collected from the O_2 analyzers and the fuel flow meters are beneficial in terms of predicting NO_x emissions. The staff has retained the installation of the O_2 analyzers and totalizing fuel flow meters in §117.213(a). See the following comment by Champion for the staff's response to the requirement of totalizing fuel flow meters, as well.

Champion objected to the requirement in §117.213(a) which requires the installation of a totalizing fuel flow meter. Champion stated, "A fuel totalizer would be of no benefit even in situations where steam or air to fuel ratios are used as a surrogate for continuous compliance. It is recommended that this section be amended to require TACB approval of an OPMS system and that approval should be based on the merits of the system proposed "

The staff has deleted the requirement to install, calibrate, maintain, and operate an OPMS in §117.213(a), while retaining the requirement to install O_2 analyzers and totalizing fuel flow meters. See the previous response to the TCC comment in §117.213. However, the staff does not agree that the requirement to install totalizing fuel flow meters would serve no benefit. At a minimum, fuel usage data is beneficial to TACB since it gives the TACB staff actual operating histories of affected equipment. This information will assist the staff in setting emission limits, determining compliance with the proposed rule as far as low capacity unit exemptions, and presenting data with which the staff can estimate NO_x emissions. See the earlier response to TCC's comment in §117.213, as well.

TMOGA and Mobil stated that the continuous determination of compliance by parametric modeling will not occur until after EPA has published guidelines and procedures for developing parametric models. Units which do not require CEMS should be stack tested under §117.211, after which no further testing of these units would be required, unless specifically requested by the TACB.

They also suggested that §117.213(a) clarify that the initial demonstration of compliance will be by the performance test determination of the emission rate and will be utilized as data for use in the site-wide demonstration of compliance.

The staff has deleted of the parametric modeling requirements of §117. 213(a) because of the lack of federal guidance on developing these methods, and fundamental staff concerns about the capability of such methods to adequately characterize NO_x emissions from boilers and heaters. If parametric methods are developed, the staff believes they would need to be reviewed case-by-case by the staff, which is not practical by May 31, 1995. The staff may addres in future rulemaking the issue of appropriate methods for demonstrating continuous compliance for industrial boilers in the 100.0 MMBtu/hr heat input to 250.0 MMBtu/hr heat input range and process heaters in the 100.0 MMBtu/hr heat input to 200.0 MMBtu/hr heat input range. See response in this section to TCC's suggestion to delete the requirement to develop operating parameter monitoring methods.

The staff clarifies that the initial demonstration of compliance as specified in §117.211 provides the test procedures for determining initial compliance with either the individual emission limits of §117.205 or the plant-wide limits of §117.207. The staff disagrees with the commenters that §117.213(a) should clarify the method for the initial demonstration of compliance, since §117.213 applies to ongoing demonstration of compliance after the initial demonstration.

Shell suggested revising the wording in §117.213(b) to reflect that CEMS and fuel flow meters should measure NO_x on a 30-day rolling average, not an hourly average.

The staff agrees and has modified the wording in §117.213(b) to reflect the 30-day rolling average. See the earlier response to TCC's comment in §117.205.

Oxy, Phillips, Shell, Star, and Sterling suggested elimination of the CEMS requirements in §117.213(b) and, wherever possible, use of an OPMS to monitor NO_x emissions See the response to TMOGA's comment in §117.207 and the response to TCC's comment in §117.213 for the staff's position on OPMS.

Oxy stated, "It should be pointed out that the monitoring of CO is rather difficult and expensive. Whatever is the perceived advantage of CO monitoring, it is certainly lost due to the poor reliability of the instrumentation used and the quality of data obtained. At any rate, the imposition of a CO limit within the NO_x rule is inappropriate."

The staff's position is that CO monitoring is accurate and reliable. The masking effects of water and carbon dioxide (CO_2) are not a problem for current monitors using nondispersive infrared spectrophotometry as the measurement technique. A unique solution to the masking effects of water and CO_2 is to place the detector cells in series rather than in parallel. The method is known as negative filtering, and use of this method yields quite accurate data. Nondispersive infrared spectrophotometry is used also as the test method to demonstrate compliance for the 100 ppmv CO limit for BIF units. It is true that CO-trim combustion control has not gained widespread use. Although it is a system whose technology is reliable and effective, other methods of control were developed that supplanted CO-trim. See the earlier response to Amoco Oil's comment in §117.205 for additional discussion.

TCC requested that the exempted units listed in §117.205(f)(3)-(5) also be exempt from CEMS requirements. The staff agrees with the request. The staff's intention in the proposed rule was not to require the installation of CEMS on the units in §117.205(f)(3)-(5). The staff anticipates the need to extend NO_x RACT requirements to all major sources. The staff will consider in future rulemaking placing emission limitations and monitoring requirements on the currently exempted equipment in the proposed rule. For clarity in this round of rulemaking, the staff has specified that the units in §117.205(f)(3)-(5) are not subject to CEMS monitoring requirements.

TCC, Amoco Chem, Amoco Oil, and Sterling requested the allowance of "switching" of up to four stacks (or multiple stacks according to Amoco Chem and Amoco Oil) for stack monitoring using only one CEMS. The staff agrees with the concept of switching using one CEMS to monitor multiple units and will allow up to three units be monitored by each CEMS. The CEMS would still need to obtain four data points per hour per unit. The CEMS certification procedures and relative accuracy test audit (RATA) must still be met. Based on previous experience, the staff believes that units with similar exhaust streams are the best candidates for meeting these accuracy requirements. The sharing of more than three units tends to be technically impracticable and may increase data unavailability due to CEMS downtime.

TCC, TMOGA, Amoco Oil, Chevron, Exxon Chem, and Sterling requested that TACB allow four quarterly cylinder gas audits (CGA), with the fourth CGA substituting for the annual RATA, as required in §117.213(b). Section 117. 213(b) has been modified to provide that in lieu of the annual RATA, a fourth CGA be performed as the quality assurance procedure for CEMS, along with requiring three quarterly CGA's. Also, the section now references 40 CFR 60, Appendix F, Procedure 1, §5.1.2 for the CGA quality assurance procedure.

TCC, TMOGA, Amoco Oil, and Exxon Chem requested that TACB allow for an alternative design of the sampling port as referenced in TCC's Attachment II. The staff agrees with the commenters about the difficulty of locating the sampling ports in reference to 40 CFR 60.13 on existing equipment. The staff expects to give procedural guidance on this and other testing issues.

Amoco Chem and Amoco Oil requested that the TACB allow the use of either an O_2 or a CO diluent monitor in §117.213(b), but not both. The CO monitor measures the concentration of CO, and is not to be used as a diluent monitor. The O_2 monitor measures the stack gas O_2 level, and is used as a diluent monitor. As an alternate, a CO_2 monitor could be installed as a diluent monitor, but an O_2 monitor would still have to be installed to measure the stack gas O_2 level.

Exxon Chem requested that the words "in stack" in §117.213(b) be replaced with "exhaust" to allow different placement of CEMS in existing equipment. The staff agrees with this comment and believes that CEMS installation should be given some latitude in installation location. If EPA guidelines for placement of CEMS cannot be followed, then the owner or operator should be able to install a CEMS in the next best location for measuring NO_x, as long as the location is representative in characterizing the emissions being emitted to the environment. The staff has changed the word "exhaust" to the words "in stack" in §117.213(b).

Amoco Chem and Amoco Oil requested an allowance for heaters with two identical stacks to install CEMS on only one stack but still provide separate O_2 analyzers on each stack. The staff's position is that if one CEMS is allowed to monitor up to three stacks, then this particular twin stack arrangement should still have both stacks monitored with one CEMS monitor. The current operating practice of Amoco Chem is to keep both sides of the heater as uniform as possible, which indicates that they have separated control over each side. Also, Monitoring NO_x emissions from each stack will help tell Amoco Chem how closely their process control is affecting NO_x emissions.

TCC, TMOGA, Exxon Chem, and Enron commented than in §117.213(b)(3), CEMS should not be required for gas turbines rated more than 30 MW, and that parametric modeling should be allowed as an alternative. TCC and Dow suggested that parametric modeling of gas turbine emissions could result in overestimation of NO_x emissions compared to direct measurement by CEMS. Amoco Oil commented that poor mixing in the turbine exhaust makes CEMS' accuracy questionable. Enron stated that enforcing the NO_x limit may be difficult with turbine and duct burner combinations. Only a limited number of units of any type (fewer than 10% of major emitters) will be required to have NO_x CEMS under the rule. As a whole, monitors are required on the largest emission sources, thus maximizing the NO_x emissions directly measured for enforcement. The 45 gas turbines rated more than 30 MW are among the largest emitters in the area. The 1988 emissions inventory showed that 31 of the largest 50 industrial NO_x emitters are gas turbines rated more than 30 MW. The total number of gas turbine CEMS required by the rule could be fewer than 25, or one-sixth of the total turbine population, with the recommendation to allow sharing of one CEMS by up to three turbines at appropriate sites.

A small change in NO_x concentration in the gas turbine exhaust will affect total emissions to a greater degree than comparable changes for boilers and heaters because of the higher exhaust air flow rates of gas turbines. Parametric modeling will not be sensitive to all factors which affect emissions. If parametric modeling is more conservative than CEMS, industry could benefit from gas turbine CEMS, since demonstrating lower actual emissions could reduce the amount of reductions needed in the future. Also, the large gas turbines are good candidates for more effective emission control technologies such as dry low-NO_x burners and selective catalytic reduction. If these advanced control methods were applied under a market-oriented control strategy, an industrial purchaser of emission reduction credits resulting from use of these technologies would be assured of full value.

Amoco Oil's concern about poor mixing does not account for the loss of stratification which may be present very near the turbine exit. The turbine power blades provide exhaust stream mixing but also may "throw" the bulk flow cyclonically. EPA siting requirements and the staff's review of alternative sites will ensure that the CEMS will be placed in a representative location in the exhaust stream.

With regard to enforcement difficulties caused by turbine and duct burner combinations, the rule does not require the CEMS to be located in front of any duct burner. If the CEMS accounts for the duct burner emission contribution in a manner that allows turbine compliance to be determined (as is done routinely for permitted sources), an in-stack location would be preferred.

Oxy and Nalco suggested eliminating the CEMS requirements in §117.213(b)(4) for units using a chemical reagent for NO_x reductions. They stated that CEMS requirements should be based on unit size and type alone. The staff disagrees with this suggestion. The requirement for NO_x CEMS on these types of controlled units is necessary for the purposes of continuous demonstration of compliance and relates to the staff's position on OPMS reliability.

Amoco Chem and Amoco Oil pointed out that there are other devices which can monitor the fuel flow usage but would not fit a strict definition of "meter." They stated that there are also instances in which units may have zero fuel flow, such as, with a low annual capacity boiler or heater. The staff's definition of totalizing fuel flow meters takes into account the concern of these commenters that the devices that they currently use to monitor fuel flow may not fit the definition of "meter." The staff's intent is that a totalizing fuel flow meter should log the fuel flow on a nonresettable, mechanical readout, or transmit electronic data to allow fuel usage totalization to be performed by a computer. For low annual capacity boilers or heaters which are rendered inoperable by installing blind flanges with carseals, these units would qualify as having zero fuel flow. If the blind flanges or carseals were to be removed and fuel was supplied to the unit, then the fuel usage would have to be monitored through a totalizing fuel flow meter.

TCC and Exxon Chem do not see the value of installing fuel flow meters in §117.213(c) and requested that the subsection be deleted. The staff disagrees. The rule requires the installation of totalizing fuel flow meters on the equipment outlined in §117.213(c) due to the potential of each of these units to be classified as a major source of NO_x emissions. Testing requirements will establish NO_x emissions at specific firing rates, and fuel usage data will provide the TACB with information which would allow the TACB to ascertain the level of NO_x emissions based on fuel usage and testing results. In addition, this data will be beneficial in determining future RACT limits for equipment in these size categories.

GHASP recommended that the option for installing elapsed time meters in §117.213(d) be removed and that biennial stack testing be required for all affected units. The referenced option of installing an elapsed time meter in lieu of performing biennial engine stack sampling was obtained from revised TACB Standard Exemption Number 6, effective July 20, 1992. The relaxation in frequency of testing requirements was negotiated with industry for engines which are frequently relocated. Since relocated engines are treated as new sources subject to the nonattainment requirements under Chapter 116, the NO_x RACT rule could have perhaps eliminated the relaxation However, the TACB cannot make the rule more stringent than originally proposed without reproposing the rule, and the enforcement benefit is not clear at this point. In the future, Title V enhanced monitoring guidance from EPA may require more stringent methods of demonstrating continuous compliance methods for internal combustion engines. The staff is maintaining in §117.213(d) the option to perform compliance testing on either an actual run time basis or a biennial basis, as proposed.

TCC, Amoco Oil, Dow, and Exxon suggested applying the continuous monitoring requirements of §117.213(e) to gas turbines rated 30 MW or greater; TMOGA and Exxon Chem suggested the same for units rated 10 MW or greater. Dow expressed support for retaining the option for steam-to-fuel or water-to-fuel ratio monitoring. The staff is retaining the rule language as proposed in order to require CEMS on the largest NO_x emitters (see the previous response to TCC's comment under §117.213(b)). Under the proposed rule, the majority of regulated gas turbines will rely on steam-to-fuel or water-to-fuel ratio monitoring to demonstrate continuous compliance with the NO_x emission limit of §117.205(d). This type of parameter monitoring is generally supported by industry. In its comments, TCC does not give reasons why it might object to steam-to-fuel or water-to-fuel ratio monitoring for units between 10 and 30 MW. TMOGA's and Exxon's comments apparently correct for this discrepancy by suggesting parameter monitoring for all regulated turbines.

TCC, TMOGA, Dow, and Exxon Chem commented that gas turbines not using steam or water injection for NO_x control (or gas turbines using dry low-NO_x combustors) should install totalizing fuel flow meters. The staff intended the requirement in §117.213(c)(4) for stationary gas turbines to install totalizing fuel flow meters to apply to all gas turbines rated 1 MW or greater. However, as worded in the proposed rule, this requirement would apply only to turbines rated between 1 and 10 MW. In keeping with APTRA notice requirements, the staff recommends this change for later rulemaking.

TCC suggested incorporating wording changes in §117.213(f) to reflect that some combustion units can have more than one fuel gas source, and that the total hydrogen content of all fuel gas streams must be greater than 50% by volume in order to receive a correction factor. The staff agrees with the request and has incorporated the suggested wording changes See the response to TCC's comment in §117.205.

TCC, TMOGA, Exxon Chem, Exxon, and Mobil requested that the TACB allow for alternate methods of fuel gas analysis in §117.213(f). The staff agrees with the commenters in allowing for other methods of fuel gas analysis which are demonstrated to be equivalent to those listed in §117.213(f). The staff has referred alternate methods of fuel gas analysis which are equivalent to American Society of Testing and Materials (ASTM) Method D-1945-81 and ASTM Method D-2650-83 in §117.213(f).

Dow requested consideration for fuel gas streams that are 100% hydrogen by volume. Dow suggested that the requirement for analysis of streams that are 100% hydrogen by volume be eliminated. The staff agrees with the statement that a fuel gas supply which is 100% hydrogen should not have to follow the sampling requirements as stated in §117.213(f) and has incorporated the following items into the rule. As part of the continuous demonstration of compliance, the hydrogen fuel gas stream shall be analyzed initially to demonstrate that the gaseous fuel is 99% hydrogen by volume or greater. The process flow diagram of the process unit that is the source of the hydrogen shall be supplied to the TACB to illustrate the source and supply of the hydrogen stream. The affected person will be required to certify that the gaseous fuel stream containing hydrogen will continuously remain, as a minimum, at 99 percent hydrogen by volume or greater during its use as a fuel to the combustion source.

TCC, TMOGA, Dow, Exxon Chem, and Exxon suggested incorporating wording changes in §117.213(h) for 30-day rolling averages, mass emission loading, and facility caps.

The staff has previously addressed these comments. The staff recommends emission limits based on a 30-day rolling average for industrial boilers and process heaters that are monitored with CEMS; recommends not incorporating the term "mass emission loading;" and recommends addressing the concept of facility caps in future rulemaking. See the responses for 30-day rolling averages in TCC's comment in §117.205 and mass emission loading and facility caps in TCC's comment in §117.207, as well.

GHASP opposed the provision which does not allow for revisiting combustion unit labeling requirements before every five years. GHASP stated that the Executive Director needs flexibility to determine if the issue needs to be revisited earlier. The staff's intent was that the requirement was to identify equipment according to the TACB designations for facility identification numbers and emission point numbers. The staff believed that the five-year schedule for labeling was sufficient to address the intent of the requirement; however, the requirements for labeling are being deleted. See the response to TMOGA's comment in §117.211.

TCC, TMOGA, Exxon Chem, and Exxon requested that the equipment labeling requirements in §117.213(j) be deleted. The staff agrees, and is deleting the labeling requirements. See the response to TMOGA's comment in §117.211.

Section 117.215-Final Control Plan Procedures. TCC, TMOGA, Exxon Chem, and Exxon requested incorporation of the following phrases: "maximum allowable emission rate," "maximum allowable mass emission loading," and "facility cap" into §117 215(b)(1) The staff recommends modifying §117 215(b)(1) to incorporate the phrase: "maximum allowable emission rate." The implementation of the "facility cap" concept and "maximum allowable emission loading," however, will be considered during future rulemaking See the earlier response to TCC's comment in §117.207.

Amoco Oil, Oxy, Phillips, and Star suggested replacing the word "unit" with the word "plant" in §117 215(b)(1) The staff disagrees with this comment. An owner or operator of a plant who elects to achieve compliance with a plant-wide emission limitation is required to assign individual emission limitations for each affected unit within the plant These individual emission limits are important for continuous demonstration of compliance purposes and are also necessary for the TACB to be able to effectively enforce the regulation and determine compliance with the emission limits See the earlier response to TCC's comment in §117.207

EPA requested clarifying the approval process for maximum allowable NO_x emission rates for each affected unit. An owner or operator is required to assign maximum allowable emission limits to the affected units and submit a list of these units with the assigned limits to the Executive Director for approval. The Executive Director approves the assigned emission limits if he determines that the plant will be capable of complying with a plant-wide emission limitation.

Section 117 217-Revision of Final Control Plan. Regarding §117 217, concerning Revision of Final Control Plan, TCC, Amoco Chem, Amoco Oil, and Exxon Chem suggested clarifying the section to identify that this section is applicable to the final compliance plan required in §117 215. The staff agrees with the commenters in clarifying §117.217 to state that it is applicable to the final control plan required in §117 215. The staff has made wording changes to this section to clarify this point.

EPA has stated that the revisions to the final control plan should be required to be approved by the Executive Director.

The staff agrees with this comment and has incorporated appropriate wording into the proposed §117.217.

Section 117 219-Notification, Recordkeeping, and Reporting Require ments. Regarding §117 219, concerning Notification, recordkeeping, and Reporting Requirements, Chevron, Oxy, Star, and Texaco requested that the section be eliminated because the requirements are redundant with the General Rules and NSPS Chevron stated that reporting requirements for non-NSPS sources should be identical to NSPS requirements. TCC, TMOGA, Exxon Chem, and Texaco proposed a new subsection that states that notification, record-keeping, and reporting for NSPS units fulfill the requirements of §117.219 Star commented that excessive reporting requirements only enable the TACB to extract large fines for paperwork errors. The requirements for notification, recordkeeping, and reporting in the rule are essential for the agency to maintain track of the progress made toward compliance with the rule, for enforcement purposes necessary to ensure compliance with the rule, and to assist in the development of future rules. The current federal NSPS, Subpart A, General Provisions, for recordkeeping and reporting have been followed as a model for virtually every requirement, except for fuel use records, which are needed to establish mass emission rates over time. The rule will extend the NSPS recordkeeping and reporting requirements to existing sources. By following NSPS, the staff believes redundant requirements have been minimized.

TCC, TMOGA, Amoco Chem, Amoco Oil, Exxon Chem, and Mobil requested that the hourly record requirement in §117.219(a) be deleted because it is already covered in the General Rules. The staff disagrees with the commenters. Section 101.7 requires notification of maintenance-related emissions but does not require recordkeeping of pertinent data onsite as does §117.219(a).

EPA requested that they also be able to inspect the records required in §117 219(a). The staff agrees with this comment and the rule language has been changed to allow records to be available for inspection by the TACB, EPA, as well as any local air pollution control agency having jurisdiction.

GHASP requested that the local agencies also be notified of testing and receive test reports as required in the proposed §117.219. The staff agrees with the comment and the rule language has been changed to allow the local air pollution control agencies to be notified of testing and to receive test reports, since these procedures are standard convention with the local air pollution control agencies.

TCC, Amoco Chem, Amoco Oil, and Exxon Chem requested that §117.219(b)(1) be deleted because they do not see the need to notify the TACB of performance testing TMOGA and Mobil suggested that the TACB should only be notified about testing performed by certified performance testers. The staff believes that notification of testing done to comply with the proposed rule is important, especially since the TACB representatives will not be required to be present during the testing. However, the staff believes that a relaxation of the notification requirements will enable the affected persons to complete the testing without restraint. The staff has reworded §117.219(b)(1) to require verbal notification 15 days before any testing is to be done, with a written notice sent within 15 days after testing is completed. TCC, TMOGA, Exxon Chem, Exxon, and Mobil requested that the TACB change the submittal dates in §117. 219(c) for the stack testing and CEMS performance testing results.

TCC, Exxon Chem, and Exxon stated that the results of performance testing and CEMS performance evaluations should be submitted 90 days after such testing is done, and results used for demonstrating compliance with §117.520 should be submitted 30 days after the final compliance date. TMOGA and Mobil requested that the results of the CEMS performance testing should be submitted by the final compliance date. The staff agrees with the request to submit performance testing results by the final compliance date. The testing requirements have been relaxed, and the staff does not believe that additional time beyond the final compliance date to submit the performance testing results is needed. The staff is retaining the requirement that the CEMS performance testing results be submitted by the final compliance date as proposed in §117.520(2).

GHASP requested that the TACB should be notified of exceedances in §117. 219(d) within 24 hours and receive a written report within 10 days, in addition to the quarterly summary reports. The staff proposed the requirements in §117.219(d) based on information that the agency normally requests in such circumstances. The staff notes that the quarterly reporting of excess emissions is independent of the requirements for reporting emission exceedances as soon as possible after occurrence of upsets under §101.6. The staff is retaining the subsection as proposed.

TCC and Exxon Chem recommended that the reporting of excess emissions in §117.219(d) not include reporting upset or maintenance emissions since these emissions are already required to be reported in the General Rules. The staff is requesting that exceedances of the applicable emission limitations of §117.205 or §117.207 be reported. The reports required in the General Rules will satisfy the identical request for reports that may be required in §117.219, so that any duplication of effort is not necessary. Other notification requirements of the proposed subsection (d) in §117.219 concerning exceedances shall be adhered to by the owner or operator. The staff is retaining the subsection as it is proposed.

TCC, TMOGA, Amoco Oil, Chevron, Exxon Chem, Exxon, Mobil, Phillips, and Star requested that the requirements for equipment labeling in §117.219(g) be eliminated.

The staff disagrees and is retaining the subsection as proposed. See the earlier response to TMOGA's comment in §117.211.

Section 117.220-Alternate Methods of Control. Regarding §117. 220, concerning Alternate Methods of Control, Chevron stated that this section is important for flexibility, and should be retained. Exxon Chem, Exxon, and EPA stated that §117.220 is unnecessary and should be deleted, since regulation specifies emission limits, not control methods, alternate RACT determination through the proposed §117.221 is more appropriate. Section 117. 220 has been withdrawn. Section 117.205 specifies RACT emission limits and not RACT methods of control or control equipment The affected industry is given the choice to decide on the best method of control to comply with those emission limits. Approving an alternate RACT determination as provided in §117.221 rather than an alternate method of control, is the more appropriate approach.

Section 117.221-Alternative Case Specific Specifications Regarding §117.221, concerning Alternative Case Specific Specifications, GHASP stated that this section should also consider effects on human health, welfare, and the environment in addition to technological and economic factors. The staff agrees with this comment and would expect the Executive Director to consider these factors in the review process.

EPA stated that emission reductions which are "substantially equivalent" to limits of §117.205 are not necessary. RACT should be based on technical and economical considerations. EPA also stated that any alternate RACT determination must be approved by EPA. The staff agrees with this comment and has made wording changes relating to EPA approval in §117.221 to reflect this concern.

TCC, TMOGA, Amoco Oil, Exxon Chem, Oxy, Phillips, Star, and B&B stated that this section should include language which allows the Executive Director's decision to be appealed to the Board (not a contested case hearing) and an arbitrator to be selected. The commenters also requested that the last sentence, "approval does not necessarily satisfy federal requirements," be deleted. The staff agrees with the comment on the inclusion of an appeals procedure. Appeals to the Board for Executive Director decisions pertaining to permitting are allowed under §103.81. The staff has incorporated language into §117.221 to allow for an appeals procedure. The comment requesting the deletion of the last sentence, which states that approval does not necessarily satisfy federal requirements, is contrary to an EPA requirement. Therefore, the staff recommends that the wording concerning EPA approval be retained in §117.221.

Amoco Oil, Oxy, Phillips, TCC, GHP, and Star expressed support for the provisions in §117.221 and recommended no changes to the proposed section.

EPA stated that it is not apparent why §117.221 is necessary, since the authority to approve an alternate control method is given under §117.220. The staff believes approving an alternate RACT determination is more appropriate than approving an alternate method of control, since the rule specifies emission rates and not control methods. Section §117.220 has been withdrawn.

EPA stated that a plant using a plant-wide emission limit should not be allowed to apply for alternate RACT limit for any unit in the plant. An alternate RACT limit for an affected unit may only be granted if the Executive Director, after considering the technological and economic circumstances, determines that the unit is incapable of meeting the emission rates of either §117.205 or §117.207. Although the staff agrees with the concept of this comment, the staff believes some flexibility should be permitted by granting the affected industry the right to make their case to the Executive Director regarding alternate RACT determinations. The affected industry will, however, be required in this case to provide proof that they were unable to meet a plant-wide emission limitation after the application of RACT. See the earlier response to TCC's comment in §117.207 for further discussion.

General Comments. Regarding general comments on Subchapter C (Acid Manufacturing), TCC and DuPont recommended the elimination of rules for adipic and nitric acid plants, stating that these sources make an insignificant contribution to overall NO_x emissions. Miles noted that a typical power plant emits more NO_x per hour than its nitric acid plant emits in a year.

There are four nitric acid plants and one adipic acid plant affected by the rule; together, they contribute about 0.2% of the total NO_x emissions subject to emission limits by the rule. Although the percentage contribution is small, nitric and adipic acid plants are nonetheless "major sources" (defined by the 1990 FCAA Amendments as having the potential to emit 25 tons per year for sources in the Houston area or 50 tons per year for sources in the Beaumont area) and therefore subject to RACT rulemaking. For source categories such as nitric acid and adipic acid plants, which have relatively few affected sources, comparing these emissions to the total emissions of all regulated sources or to emissions from specific large sources is not meaningful or appropriate as a criterion for control.

DuPont commented that many combustion sources emit much more NO_x than adipic or nitric acid plants, but are exempted by the rule. The staff considered several factors in the development of exemptions, including the time available to develop regulations by November 15, 1992, the availability of EPA technical guidance, and economic reasonableness and technical feasibility of control. The first NO_x RACT technical guidance EPA provided the states was for nitric and adipic acid manufacturing plants, in December 1991. The availability of this ACT document facilitated the staff's early development of the required NO_x RACT regulations. Although the staff now has ACT guidance for most major stationary source categories covering probably more than 95% of total major stationary source emissions, some categories remain unaddressed. The staff intends to develop appropriate regulations for all categories and size ranges of major NO_x sources in an expeditious manner. In the case of adipic and nitric acid plants, all of the affected sources currently apply control technology consistent with RACT. The intent of the current rulemaking is to set emission limits which reflect demonstrated levels of control already being achieved by these sources. Compliance with the rule would be expected to fulfill the sources' obligation under the FCAA Amendments to implement RACT, although further reductions may be required in the future to attain the ozone standard.

Section 117.305-Emission Specifications. Regarding §117.305, concerning Emission Specifications, DuPont commented that the proposed emission limit of 2.0 lb NO_x/ton adipic acid produced is not appropriate for a short-term standard, but 2.5 lb NO_x/ton is achievable with a 30-day rolling average. As reported in EPA's ACT document for nitric and adipic acid manufacturing plants, sampling of the absorber at DuPont's adipic acid plant in 1988 showed a range of NO_x emissions from 500 ppmv to 1,500 ppmv, averaged over a three-day period at the maximum operating rate. The ACT document applied an equivalence ratio to relate the permitted emission level (4,500 ppm = 700 tons per year) to the measured emission rate (500 to 1,500 ppm = 77 to 223 tons per year), then divided these annual NO_x emissions by the annual adipic acid production rate to obtain NO_x emission factors of 0.81 to 2.45 lb NO_x/ton of adipic acid produced. The ACT document assumed a linear relationship between NO_x concentration in ppmv and the annual emission rate in tons per year. The staff agrees that this assumption may not adequately account for shortterm emissions, although sampled emissions at the maximum operating rate were significantly below the permitted emission rate which was based on information supplied by DuPont. DuPont commented that NO_x emissions from the adipic acid plant absorber can be as high as 2.2 lb NO_x/ton to 2.5 lb NO_x/ton, averaged over three hours. DuPont further noted that variations in production rate and reaction temperature require a longer averaging period, and recommended a 30-day rolling average. The staff is setting the standard at 2.5 lb NO_x/ton, using a 24-hour rolling average, and believes that this represents a satisfactory compromise while addressing DuPont's concerns. §117.405 Emission Specifications. Regarding §117.405, concerning Emission Specification, Miles commented that an emission limit of 2.0 lb NO_x/ton of 100% nitric acid produced is the lowest rate achievable for strong nitric acid plants, using a 24hour rolling average. DuPont also expressed support for a 2.0 lb NO_x/ton standard on a 24-hour rolling average. DuPont recommended adoption of a 2.0 lb NO_x/ton standard, but on a 30-day rolling average. The staff has reviewed additional information since proposing the 1.0 lb NO_x/ton emission limit for nitric acid plants, and is setting 2.0 lb NO_x/ton of 100% nitric acid produced, with a 24-hour rolling average, as the rule emission limitation. DuPont presented comments supporting both a 24-hour and a 30-day rolling average, and the staff believes that the more restrictive 24-hour rolling average is achievable by all affected sources.

Miles and DuPont recommended that periods of start-up or shutdown should be exempt from the standard for a duration not to exceed three hours. DuPont recommended that emission specifications as well as periods of excess emissions should not apply during periods of major upset or maintenance under the TACB General Rules. The staff agrees that start-up and shutdown conditions should be exempt from the rule's emission limitations, and believes that three hours appears to be a reasonable period to exclude such emissions from applicability of the rule. The staff received numerous comments in the utility and industrial portions of the rule to the effect that the start-up/shutdown exemptions were unnecessary, since §101.11(b) already provides this exemption. The staff agrees with these commenters. Although the staff rule proposal defines the length of start-up/shutdown periods for electric utility units, as allowed in §101.11, it does not for industrial units. The staff now believes that more work would be needed to develop technically sound time periods for start-up/shutdown for the various categories of industrial combustion sources. For the sake of rule consistency, the staff has made no changes to the proposed rule regarding the length of start-up and shutdown periods at this time.

Miles recommended the addition of a 600 ppmv limit based on a 24hour rolling average for nitric acid plants. Prior to proposal of the current rule, §117.2 of Regulation VII set an emission standard of 600 ppmv for all nitric acid manufacturing plants in the state. The 600 ppmv limitation is equivalent to 7.0 lb NO_x/ton 8.0 lb NO_x/ton of 100% acid, compared to the 2.0 lb NO_x/ton standard (applicable only in designated counties in the Houston and Beaumont ozone nonattainment areas) in the current rule proposal. Since all four affected nitric acid plants typically operate well within the 2.0 lb NO_x/ton range, and since exemption of start-up, shutdown, and maintenance conditions is already provided by TACB General Rule §101.11(b), the staff believes that implementing a 600 ppmv limit with a 24-hour averaging period is inconsistent with RACT and, therefore, inappropriate.

Section 117.309, §117.409-Control Plan Procedures. DuPont objected to the detailed reporting requirements in §117.309(1)-(4) and §117.409(1)-(4), claiming that this would set a precedent, and suggested more general language for control plan requirements.

The staff patterned the control plan procedures in §117.309 and §117. 409 after procedures set forth in §115.932 of TACB Regulation V, "Control of Air Pollution from Volatile Organic Compounds," using almost identical language, so in this respect the staff does not agree that implementing such requirements in the proposed rule would set a precedent. DuPont's proposed language, referring to "major milestones in the implementation process," would be expected to result in reporting the same dates and schedules as contained in the proposed rule. In addition, the only equipment likely to be ordered and installed to achieve compliance with the rule, and therefore subject to the reporting requirements of this section, is the NO_x CEMS for DuPont's adipic acid plant. The staff recommends adding language to §117.309 and §117.409 providing for approvability requirements and revisions to the control plan, replacing "exact dates" with "anticipated dates," and retaining paragraphs (1)-(4).

Section 117.313(c), §117.413(c)-Continuous Demonstration of Compli ance. DuPont recommended that a CGA be allowed once per calendar quarter in lieu of the annual RATA in order to meet the CEMS auditing requirements of §117.313(b) and §117.413(b).

The staff agrees, and recommends changes to §117.313(b) and §117.413(b) as reflected in the response to TCC et al. under §117.213.

Regarding §117.313(c) and §117.413(c), concerning Continuous Demonstration of Compliance, Miles suggested that emissions data be expressed in ppmv and lb/hr, on a rolling 24-hour average. DuPont recommended using a rolling 30-day average. Procedures are specified in §117.413(c) for expressing recorded CEMS data in terms of both ppmv and lbs/ton acid produced. The staff believes this will be adequate for field inspectors and plant operations personnel to accurately determine emissions by observing CEMS readouts. Expressing recorded emissions data in lb/hr is optional, but not necessary to verify compliance with the standard. With regard to the averaging period for continuous emission monitors, see the response to Miles under §117.319, §117.419.

Section 117.319, §117.419-Notification, Recordkeeping, and Reporting Requirements. Regarding §117.319 and §117.419, concerning Notification, Recordkeeping, and Reporting, Miles recommended that a 24-hour rolling average and 24 contiguous one-hour periods be incorporated into the wording of §117.419. DuPont recommended incorporating a rolling 30-day average and 30 contiguous 24hour periods in §117.319 and §117.419. As originally proposed, §117.419(c) defined a period of excess emissions as any threehour period in which the average NO_x emissions (arithmetic average of three contiguous one-hour periods) as measured by a CEMS exceeded the standard. The staff has revised this section to reflect that a 24-hour rolling average, consisting of 24 contiguous one-hour periods, will be used to determine periods of excess emissions. A minimum of four data points are required for each hourly period. The staff has revised §117.319, the corresponding rule for adipic acid plants, to reflect a rolling 24-hour averaging period.

Section 117.321, §117.421-Alternative Case Specific Specifications. Regarding §117.321 and §117.421, concerning Alternative Case Specific Specifications, Miles commented that differences between weak and strong nitric acid plants justify alternative case flexibility; the regulations may not be applicable to both types of plants. The staff recognizes differences between weak and strong nitric acid plants and believes the standard is achievable for both types of plants. The rule is applicable to both weak and strong nitric acid plants.

DuPont recommended inclusion of a procedure for appealing decisions of the Executive Director to the Board in §117.321 and §117.421. The staff agrees and is adding appeal provisions to §117.321 and §117.421. See the response to TCC et al. at §117.221.

Section 117.510-Compliance Schedule for Utility Electric Generation. HL&P suggested that the requirement for progress reports in §117.510(2) is unnecessary and should be deleted. The staff agrees that progress reports are not necessary unless a source is complying with a phased RACT approach. In that case, compliance with approved compliance milestones in accordance with §117.540(a) are enforceable and will represent RACT, so progress reports will be necessary to facilitate enforcement. Phased RACT reporting requirements may be implemented in supplementary rulemaking which EPA recommends to create a replicable procedure by the state in granting phased RACT without the need for EPA approval. Phased RACT requirements are addressed in §117.540, so the staff has eliminated the requirement for progress reports and deleted §117.510(2).

HL&P stated that if progress reporting per §117.510(2) is not deleted, its requirements should be made consistent with industrial progress report requirements. This includes compliance status, reporting requirements, and completed milestones during the compliance implementation period. The staff agrees. Section 117.510(2) has been deleted.

HL&P suggested that §117.510(3) and §117.119 are redundant, but the dates in the two sections are not. They should be revised for consistency The staff does not believe that §117.119 and §117.510 are redundant, since §117.119 specifies details of notification, recordkeeping, and reporting, while §117 510 gives schedules However, the dates specified in §117.510(3) and §117.119(c) are inconsistent. The staff has revised §117.510(3) and §117.510(4) to require submittal of continuous monitor evaluations by May 31, 1995

HL&P said that the dates in §117 510 should be made consistent with the dates specified under §117.115. Since §117.115 does not specify any dates except to refer to the final compliance date identified in §117.510, the claim of inconsistency cannot be substantiated.

GSU suggested that §117 510 relax from five days to one month the requirement for notification of completion of each separate step in a compliance plan.

See the previous response to HL&P's comment

GSU recommended that the specific 250 ton per year CO increase which triggers permit amendments should be removed, and that permits or permit amendments should only be required for projects which are not environmentally beneficial. See the response at §117.550 to comments of TCC et al regarding permit requirements.

Section 117.520-Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources. Star, Texaco, and Chevron voiced their opinion that the May 31, 1995, final compliance date in §117.520 is unrealistic. The staff recognizes the difficulties in scheduling to meet the final compliance date and is addressing these concerns. The staff is recommending changes in the testing dates and equipment testing methods to alleviate this particular concern. The staff has proposed §117.540 to allow the Executive Director to reevaluate the May 31, 1995 final compliance date based on control plans; availability of NO_x control equipment, engineering services, and construction labor, and the dates of planned and actual outages of units subject to the emission limitations. However, the 1990 FCAA Amendments specify a final compliance date of May 31, 1995 for NO_x controls to be implemented. Therefore, the staff believes that the proposed rule accounts for the difficulties in meeting the final compliance date in the most effective manner possible

TCC, TMOGA, Amoco Oil, Chevron, Exxon Chem, Exxon, Mobil, Oxy, and Phillips requested that the six-month progress reports be eliminated from §117.520(2).

The staff agrees with the request and has deleted that the sixmonth progress reports be deleted from §117.520(2).

Dow requested that the subparagraph listing the schedule for performing testing on modified units in §117.520(3)(A) be deleted. Exxon Chem recommended deleting the phrase "and no later than 60 days before any applicable compliance date" in §117 520(3)(A). TCC, TMOGA, Amoco Chem, Dow, Mobil, Texaco, and Enron requested an extension of the CEMS testing date to May 31, 1995 for unmodified units as required in §117.520(3)(B). Exxon Chem requested that the testing results be submitted 90 days after testing is completed. Texaco, TPC, TCC, and Chevron stated that requiring unmodified units to test by April 1, 1994 does not support the intent of the rule. The staff agrees that the schedule for testing requirements needs adjusting, and has modified §117.520(3)(A) to require at least initial emissions checks using portable emission analyzers to be completed by April 1, 1994. Further, the rule now requires that all CEMS performance testing and all compliance testing be accomplished and test results submitted by May 31, 1995. TMOGA and Mobil requested that TACB recognize a CEMS installation on an unmodified unit as being a modification, or require 50% of CEMS orders to be placed by April 1, 1994. The staff disagrees with the commenters The staff believes that CEMS installations do not qualify the unit as being modified. For the purposes of this paragraph, a modified unit is meant to be a unit that has NO_x abatement equipment installed to make NO_x reductions. The staff has made changes to the compliance schedule for testing requirements See the previous response to Dow's comment in §117.221.

Section 117.530-Compliance Schedule For Nitric Acid and Adipic Acid Manufacturing Sources Miles stated that the final compliance date of May 31, 1995 in §117.530 is overly optimistic. Although the impact of the May 31, 1995 final compliance date upon affected sources will vary, it does not appear to be a problem for nitric and adipic acid plants, which currently appear to be substantially in compliance with the proposed standards. See the staff's response to Star's comment under §117.520, relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources.

DuPont recommended that the requirement for 60-day progress reports be eliminated from §117.530(2) for nitric acid and adipic acid plants. The staff agrees, and has deleted the requirement for 60-day progress reports from the rule.

Section 117.540-Compliance Schedule Deviation TCC, Amoco Chem, Amoco Oil, Chevron, Dow, Exxon Chem, Exxon, Oxy, Phillips, Star, HL&P, and B&B expressed support for extending compliance dates through EPA's phased implementation approach. Although the proposed final compliance date is thought to be generally reasonable, the TACB staff recognizes the possibility that full implementation of the emission reductions required in this rule by May 31, 1995 may not be reasonable in every case.

EPA opposed the language contained in §117.540 and stated that the section should be revised to reflect the provisions of the EPA's Title I General Preamble. EPA listed provisions which must be included in the rulemaking in order for it to be approvable. EPA published its policy guidance in the *NO_x* Supplement to the General Preamble on November 25, 1992, five days after TACB proposed the NO_x RACT rules. The staff has reworded §117.540(a) in accordance with the specifications of EPA's February 12, 1992 comment letter to allow for the definition of RACT as a set of phased measures.

Exxon recommended cost-justified alternate compliance schedule procedures. The staff believes that the final compliance date can fundamentally affect RACT cost. A market axiom is that if implementation of a cost item can be postponed successfully, it is cost-effective. The staff also recognizes that an implementation schedule can have a greater effect on a rule's costs than the cost of required emission control equipment. This may be particularly applicable to continuously operating processes and in instances where emission control technology is rapidly evolving. The staff has considered the time available for the implementation of control technology in the development of the proposed emission limits, and believes it to be reasonable However, in view of the rapid developments in this area, the staff plans to review the May 31, 1995 compliance date in April of 1994 to determine whether any change is appropriate

The FCAA requires all RACT to be installed by May 31, 1995. As written, it does not explicitly allow for cost-based extensions. EPA's interpretation of the RACT requirements allows for consideration of the unavailability of equipment and the effects of RACT implementation on system reliability.

Also, costs of delaying rules are also difficult to assess from the environmental standpoint. Second-round emission reductions could be more difficult to implement in a timely fashion if these first-round reductions are delayed. Such delays would be likely to reduce the probability of achieving the ozone standard in Beaumont by 1999 or Houston by 2007, which increases costs in terms of public health and welfare. The FCAA requirements reflect a general consensus that failure to implement timely emissions reductions will result in unacceptable costs to the environment. The FCAA provisions for "bump-up" which require more stringent future emission requirements for failure to attain the ozone standard should also be considered in evaluation of a phased schedule. Industry's failure to implement cost-effective controls in a timely fashion could cause bump-up costs to be imposed on persons who otherwise would not be affected.

Miles suggested adding wording allowing process modifications as a factor in granting a compliance schedule extension. Star suggested that problems with equipment delivery or unit turnaround schedules be considered when evaluating requests for compliance date extensions. The staff does not believe that compliance extensions should generally be deferred until process modifications occur. The staff does believe that routine maintenance or unit turnarounds may be considered as a factor in evaluating cost-effectiveness of installing controls by May 31, 1995, since these may be related to system reliability. Units that will undergo process modifications after May 31, 1995 may be able to defer controls now under plant-wide averaging and take credit for the new emission controls in a later round of NO_x reductions.

EPA suggested that further rulemaking be considered to incorporate future EPA guidance on replicable procedures to avoid the need for case-by-case EPA approval for phased RACT EPA does not have a scheduled date for providing national guidance on replicable procedures which would allow states to approve phased RACT without case-by-case EPA approval. After consultation with the EPA Region 6 office, the staff recommends a second-round proposal for rulemaking to provide such replicable procedures. This proposal may be patterned on the replicable procedures EPA has provided for "Phase I NO_x Compliance Extensions" for coal-fired electric utility boilers subject to the low-NO_x burner requirements of FCAA Title IV

HL&P and B&B commented that initial control plans should only be planning documents, except in cases where sources will be unable to meet the May 31, 1995 compliance deadline They suggested removing the blanket prohibition of deviation from terms of the control plans, and recommended language to specify that compliance plan milestones are enforceable only in instances where sources will be unable to meet the May 31, 1995 deadline. Oxy suggested including §117.109 and §117.209, relating to Initial Control Plan Procedures, in the list of rules eligible for compliance schedule deviation GHASP suggested public notice and hearing if affected sources deviate from their initial compliance plans in §117.540(a).

The language specified by EPA in their February 12, 1993 comments on phased RACT does not include the requirement that no person shall deviate from the terms of the initial compliance plan. The staff has replaced the first two sentences of proposed §117.540(a) with the language specified by EPA. The staff agrees that persons who do not seek a phased RACT schedule and who comply with the rule requirements by May 31, 1995 should not be held to the terms of the initial compliance plans, since in these cases the plan is only a planning document. The final compliance plan is used to determine compliance in cases where rule compliance is achieved by May 31, 1995. On the other hand, approval of a phased RACT schedule necessitates enforceable provisions requiring implementation of specific steps in a plan. The terms of the initial compliance plan should be used to develop an approvable phased compliance schedule.

TCC, Amoco Oil, Chevron, Dow, Exxon Chem, Exxon, Oxy, Phillips, B & B, and Star suggested the need to specify a mechanism to appeal the Executive Director's decisions under §117.540(a). Star commented that an independent arbitrator should be selected. These comments are well taken, and the staff has added language for an appeal mechanism in this section of the rule. However, the TACB cannot and should not delegate its authority to an independent arbitrator. Therefore, no provisions for arbitration are being recommended.

Phillips and Star expressed support for reevaluation of final compliance dates one year after rule adoption. Sterling suggested determination of final compliance dates within six months of rule adoption. There is a need to recognize that some sources can meet the May 31, 1995 compliance deadline, whereas others may not be able to. The rule provides a mechanism to reevaluate final compliance dates one year after adoption. The staff believes that this timetable is adequate to address the relevant issues that may arise between now and May 31, 1995, and does not recommend reevaluation of final compliance dates any sooner than one year from the date of rule adoption.

EPA commented that §117 540(b), which provides for reevaluation of the final compliance date by the TACB rulemaking, should be made consistent with the phased RACT approach outlined in the *NO_x* Supplement to the General Preamble TCC, Amoco Oil, Exxon Chem, HL&P, and B&B suggested rewording the subsection to reflect phased RACT. The staff has made revisions to §117 540 which would incorporate phased RACT requirements into the rule, making it consistent with guidance from the NO_x RACT Supplement and the EPA Region 6 office The staff believes that the adopted version satisfies the commenters' requests.

B&B commented that appeal of rulemaking decisions is provided for in TACB Chapter 103, Procedural Rules, making an appeals procedure in §117 540(b) unnecessary The staff agrees that a procedure for the appeal of rulemaking decisions is already established by the Texas Clean Air Act, and does not recommend including a specific appeals procedure for this portion of the rule.

Section 117 550–Permit Requirements. Star, Chevron, and Mobil suggested that permitting provisions in §117 550 need to be as flexible as possible. HL&P stated that compliance deadlines cannot be met if construction permits are required. TCC, TMOGA, and Exxon suggested that permits should not be required if capacity increase results solely from NO_x RACT control measures.

Oxy and Phillips requested eliminating the phrase "must not result in an increase of the unit's or the facility's production capacity" in §117.550(a) (1) since some NO_x controls reduce emissions while increasing capacity.

The staff recognizes that if industry is to comply with the short schedule to implement NO_x RACT as required by the FCAA, there will not be time in each case to receive a permit amendment for addition of control equipment. The proposed exemption from permits has been adopted as proposed. Since publication of the proposal, industry has sought more flexible methods of authorizing NO_x emission control projects. Items of additional flexibility suggested by industry have included eliminating BACT review for production increases or for CO emission increases in excess of 100 tons per year if associated with the NO_x control project. The TACB policy to require BACT review for modifications of existing facilities which increase output could be set aside if some of these suggestions are adopted, resulting in fewer emission reductions since BACT emission limits would be avoided. The need to make use of production capability increases without caseby-case permitting has not been clearly established by industry. With CO, the available literature suggests that NO_x control technology can be operated in most cases in such a manner as to avoid CO increases. The staff has some concerns that if CO emissions are allowed to increase up to 400 ppmv in every case, CO increases far larger than reasonable may result

Exxon, GSU, and EPA expressed support for new source review exclusion for NO_x RACT controls if the exclusion was consistent with WEPCO rulemaking and the units were not rendered less "environmentally beneficial." The EPA has not extended the WEPCO utility policy by rulemaking to industrial sources as earlier suggested. EPA cited the relative small source population and uniformity of technology within the utility industry in its rationale for not extending the WEPCO utility policy immediately to non-utility source categories. The TACB staff notes that the technical literature suggests that CO increases from utility units are less likely than from smaller industrial units Nonetheless, based on EPA's comments and the desire to facilitate the rapid implementation of NO_x control projects, the staff recommends consideration of an exemption for pollution control projects which includes extending the WEPCO exclusion from federal permitting to industrial source categories in a second round of TACB rulemaking during the summer of 1993.

TCC, TMOGA, Chevron, Exxon Chem, HL&P, and GHP suggested that this §117. 550 use the General Permit provisions of the Texas Clean Air Act (TCAA) to authorize RACT controls The staff recommends that the use of General Permits, as provided by the TCAA, be addressed as a mechanism for authorizing NO_x RACT emission control projects in a rulemaking proposal initiated immediately following adoption of the current proposal In the interim, prior to any future rule adoption, the staff recognizes the compressed time schedule of the final compliance date and has proposed maintaining the current proposed exemption to facilitate emission control projects that may occur this summer which do not necessitate large CO increases.

TCC, TMOGA, and Exxon Chem suggested a revised list of conditions for increases other than NO_x which are not addressed in §117.550(2) and that a notice of intent to comply with a General Permit must be filed with the initial control plan. The staff recommends proposing future rulemaking to address capacity and corollary pollutant increases. However, the staff would propose for the General Permits to limit the cases where there would be General Permit authorization for use of capacity increases associated with the installation of NO_x controls. Some use of capacity increase should be subject to BACT permitting.

The staff considers the revised language suggested by TCC, TMOGA, and Exxon Chem to those include concepts far broader than included in the proposed rule. Therefore, because of the way that the *Texas Register* interprets APTRA to require public notice in the *Texas Register* for substantively new requirements or issues, the staff recommends that a General Permit policy be addressed in second round rulemaking.

The staff is not sure that the suggested format for notice of intent to be covered by a General Permit is beneficial. The staff recommends that the future rulemaking address these issues

Section 117.560-Rescission. The EPA requested deleting the language in §117.560 suspending rule requirements during EPA review of TACB findings, and deleting the wording concerning delaying compliance date by the amount of elapsed time of EPA review. The EPA stated that the FCAA Amendments do not provide for such actions. The staff agrees with the comment and has deleted the appropriate wording.

EPA stated that the language regarding removal of rule requirements within a given nonattainment area is not necessary; some NO_x RACT requirements could still apply if the TACB demonstrates "excess emission reductions" test of the FCAA Amendments, §182(f). The staff agrees with the comment and has deleted the wording concerning removal of the rule requirements for an affected nonattainment area. Should EPA find grounds for rescission, the staff would recommend that rulemaking be proposed to address the findings of the EPA Administrator as to the NO_x RACT requirements that would apply to the nonattainment area if the Administrator were to approve the TACB request.

TCC, Amoco Oil, Chevron, Exxon Chem, Phillips, HL&P, GSU, and Star expressed support for the rescission provisions and no changes were recommended. The staff disagrees with the commenters due to the previous EPA comments which, if not addressed by deleting the proposed wording, could jeopardize the approvability of the NO_x RACT rule.

GHASP objected to rescission, since other non-ozone related problems such as health, welfare, and environment are ignored. The staff does not completely disagree with the comment. The 1990 FCAA Amendments, §182(f)(1), state that NO_x requirements shall not apply in the case of oxides of nitrogen for those sources for which the Administrator determines (when the Administrator approves a plan or plan revision) that net air quality benefits are greater in the absence of reductions of oxides of nitrogen from the sources concerned. The staff proposed this section only to make an allowance for the possibility that rescission may be required, based on Urban Airshed Modeling results. In order to rescind the rule, net air quality benefits would be considered. The staff has made wording changes as outlined in the previous EPA's comments in this section.

Oxy stated that rescission is unnecessary if the need for NO_x reductions are established first. The staff agrees with the concept that Oxy has presented. The need for NO_x reductions has been established in the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas, based on the severity of the ozone problem, the high monitored ratios of ambient VOC to NO_x, and the results of grid modeling conducted in other areas with similar high ratios of VOC to NO_x. Rescission is not considered to be a realistic scenario, but was included to facilitate rule implementation. Since the staff did not have results from the UAM for the affected nonattainment areas before the regulation was proposed, the section on rescission is required.

Section 117.570-Alternate Means of Compliance-Trading. TMOGA, Amoco Chem, Amoco Oil, Oxy, GHP, GSU, Star and Chevron expressed support for trading provisions in §117.570. Star suggested that trading needs to be as flexible as possible to allow for costeffective NO_x compliance. The staff acknowledges the interest in expanding flexible emissions reduction programs and would plan to incorporate some of the new trading ideas into a future NO_x rulemaking.

GSU suggested that emission trading be allowed between sources in different ozone nonattainment areas under certain conditions. EPA has yet to formulate a policy on trading between different ozone nonattainment areas. There are two conditions that EPA is considering for this type of trading, based on new source offset trading provisions in the FCAA. First, credits would be obtained from an area with an equal or higher nonattainment classification as the area in which the source seeking credits is located. Second, credits should have a beneficial air quality impact on the area in which the source seeking credits is located.

TCC, Exxon Chem, and HL&P suggested that the TACB banking rule be used to allow trading of NO_x emission reduction credits for initial compliance with the NO_x RACT rule or for delayed compliance with the rule. The TACB banking rule, as adopted February 19, 1993, is limited to providing offsets for applicable nonattainment new source review rules. Extending the banking rule to facilitate NO_x RACT trading is an issue for future rulemaking.

Section 117.601-Gas-Fired Steam Generation. GHASP requested that the records in §117.601(e) should be maintained for at least four years to be consistent with other sections of the rule. The staff's intent was to only recodify the existing Regulation VII and not to make the requirements stricter. A four-year recordkeeping requirement could be considered in future rulemaking.

GHASP requested deletion of the phrase "*during regular business hours*" in §117.601(e). The staff's intent was to only recodify the old §§117.1-117.4 and not to require state and local agencies to extend or increase regular business hours.

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The repeals are adopted under the Texas Health and Safety Code, (Vernon 1990), Texas Clean Air Act, §382.017, which provides TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 19, 1993.

TRD-9323202 Lane Hartsock
Deputy Director, Air Quality Planning
Texas Air Control Board

Effective date: June 9, 1993

Proposal publication date: November 20, 1992

For further information, please call: (512) 908-1451

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Subchapter A. Definitions

• 31 TAC §117.10

The new rule is adopted under the Texas Health and Safety Code (Vernon 1990), Texas Clean Air Act, §382.017, which provides TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117.10. Definitions. Unless specifically defined in the Texas Clean Air Act or the General Rules of this title, the terms in this chapter shall have the meanings commonly used in the field of air pollution control. Additionally, the following meanings apply, unless the context clearly indicates otherwise.

Annual capacity factor–The total annual fuel consumed by a unit divided by the fuel which could be consumed by the unit if operated at its maximum rated capacity for 8,760 hours per year.

Applicable ozone nonattainment area–The following areas, as designated pursuant to the 1990 Federal Clean Air Act Amendments.

(A) Beaumont/Port Arthur ozone nonattainment area–An area consisting of Jefferson, Hardin, and Orange counties.

(B) Houston/Galveston ozone nonattainment area–An area consisting of Harris, Liberty, Waller, Chambers, Fort Bend, Galveston, Brazoria, and Montgomery counties.

Auxiliary steam boiler–Any combustion equipment within an electric power generating system, as defined in this section, that is used to produce steam for purposes other than generating electricity.

Block one-hour average–An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour.

Boiler or steam generator–Any combustion equipment fired with solid, liquid, and/or gaseous fuel used to produce steam.

Btu–British thermal unit.

Chemical processing gas turbine–A gas turbine that vents its exhaust gases into the operating stream of a chemical process.

Daily-A calendar day starting at midnight and continuing until midnight the following day.

Electric power generating system-All boilers, steam generators, auxiliary steam boilers, and gas turbines used in an electric power generating system owned or operated by a municipality or a Public Utility Commission of Texas regulated utility that are located within the Houston/Galveston or Beaumont/Port Arthur ozone nonattainment areas.

Emergency standby gas turbine or engine-A gas turbine or engine operated only as a mechanical or electrical power source for a facility when the primary power source has been rendered inoperable, except due to power interruption pursuant to an interruptible power supply agreement.

Heat input-The chemical heat released due to fuel combustion in a unit, using the higher heating value of the fuel. This does not include the sensible heat of the incoming combustion air. In the case of carbon monoxide (CO) boilers, the heat input includes the enthalpy of all regenerator off-gases and the heat of combustion of the incoming carbon monoxide and of the auxiliary fuel. The enthalpy change of the fluid catalytic cracking unit regenerator off-gases refers to the total heat content of the gas at the temperature it enters the CO boiler, referring to the heat content at 60 degrees Fahrenheit, as being zero.

High heat release rate-A ratio of boiler design heat input to firebox volume (as bounded by the front firebox wall where the burner is located, the firebox side waterwall, and extending to the level just below or in front of the first row of convection pass tubes) greater than or equal to 70,000 British thermal units (Btu) per hour per cubic foot.

Horsepower rating-The engine manufacturer's maximum continuous load rating at the lesser of the engine or driven equipment's maximum published continuous speed.

Industrial boiler or steam generator-Any combustion equipment, not including utility or auxiliary steam boilers as defined in this section, fired with liquid, solid, or gaseous fuel, that is used to produce steam.

International Standards Organization (ISO)-ISO standard conditions of 59 degrees Fahrenheit, 1.0 atmosphere, and 60% relative humidity.

Lean-burn engine-A spark-ignited or compression-ignited, Otto cycle, diesel cycle, or two-stroke engine that is operated with an exhaust stream oxygen concentration of 4.0% by volume, or greater. The exhaust gas oxygen concentration shall be determined from the uncontrolled exhaust stream.

Low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit-An industrial boiler, process heater, or gas turbine supplemental waste heat recovery unit with maximum rated capacity:

(A) greater than or equal to 40 million Btu per hour (MMBtu/hr), but less than 100 MMBtu/hr and an annual heat input less than or equal to $2.8(10^{11})$ Btu per year (Btu/yr); or

(B) greater than or equal to 100 MMBtu/hr and an annual heat input less than or equal to $2.2(10^{11})$ Btu/yr.

Low heat release rate-A ratio of boiler design heat input to firebox volume less than 70,000 Btu per hour per cubic foot.

Major Source-Any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit:

(A) at least 25 tons per year (tpy) of nitrogen oxides (NO_x) and is located in the Houston/Galveston ozone nonattainment area;

(B) at least 50 tpy of NO_x and is located in the Beaumont/Port Arthur ozone nonattainment area.

Maximum rated capacity-The maximum design heat input, expressed in MMBtu/hr, unless:

(A) the unit is a boiler, utility boiler, or process heater operated above the maximum design heat input (as averaged over any one-hour period), in which case the maximum operated hourly rate shall be used as the maximum rated capacity; or

(B) the unit is limited by operating restriction or permit condition to a lesser heat input, in which case the limiting condition shall be used as the maximum rated capacity; or

(C) the unit is a stationary gas turbine, in which case the manufacturer's rated heat consumption at the International Standards Organization (ISO) conditions shall be used as the maximum rated capacity, unless limited by permit condition to a lesser heat input, in which case the limiting condition shall be used as the maximum rated capacity; or

(D) the unit is a stationary, internal combustion engine, in which case the manufacturer's rated heat consumption at Diesel Equipment Manufacturer's Association conditions shall be used as the maximum rated capacity, unless limited by permit condition to a lesser heat input, in which case the limiting condition shall be used as the maximum rated capacity.

Megawatt (MW) rating-The continuous MW rating or mechanical equivalent by a gas turbine manufacturer at ISO conditions, without consideration to the increase in gas turbine shaft output and/or the decrease in gas turbine fuel consumption by the addition of energy recovered from exhaust heat.

Nitric acid-Nitric acid which is 30% to 100% in strength.

Nitric acid production unit-Any facility producing nitric acid by either the pressure or atmospheric pressure process.

Nitrogen oxides (NO_x)-The sum of the nitric oxide and nitrogen dioxide in the flue gas or emission point, collectively expressed as nitrogen dioxide.

Parts per million by volume (ppmv)-All ppmv emission limits specified in this rule are referenced on a dry basis.

Peaking gas turbine or engine-A stationary gas turbine or engine used intermittently to produce energy on a demand basis.

Plant-wide emission limit-The ratio of the total allowable nitrogen oxides mass emissions rate dischargeable into the atmosphere from affected units at a major source when firing at their maximum rated capacity to the total maximum rated capacities for those units.

Plant-wide emission rate-The ratio of the total actual nitrogen oxides mass emissions rate discharged into the atmosphere from affected units at a major source when firing at their maximum rated capacity to the total maximum rated capacities for those units.

Process heater-Any combustion equipment fired with liquid and/or gaseous fuel which is used to transfer heat from combustion gases to a process fluid, superheated steam, or water for the purpose of heating the process fluid or causing a chemical reaction. The term "process heater" does not apply to any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment, or to boilers or steam generators as defined in this section.

Rich-burn engine-A spark-ignited, Otto cycle, four-stroke, naturally aspirated or turbocharged engine that is operated with an exhaust stream oxygen concentration of less than 4.0% by volume. The exhaust gas oxygen concentration shall be determined from the uncontrolled exhaust stream.

Stationary gas turbine-Any gas turbine system that is gas and/or liquid fuel fired with or without power augmentation. This unit is either attached to a foundation at a facility or is portable equipment operated at a specific facility for more than 90 days in any 12-month period. Two or more gas turbines powering one shaft shall be treated as one unit.

Stationary internal combustion engine-A reciprocating engine either attached to a foundation or if not so attached is operated or is intended to be operated at a single facility for more than six months, including any replacement engine for a specific application which lasts or is intended to last for more than six months.

System-wide emission limit–The ratio of the total allowable nitrogen oxides mass emissions rate dischargeable into the atmosphere from affected units in an electric power generating system when firing at their maximum rated capacity to the total maximum rated capacities for those units.

System-wide emission rate–The ratio of the total actual nitrogen oxides mass emissions rate discharged into the atmosphere from affected units in an electric power generating system when firing at their maximum rated capacity to the total maximum rated capacities for those units.

Unit–Any boiler, steam generator, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, which is placed into service prior to November 15, 1992.

Utility boiler or steam generator–Any combustion equipment owned or operated by a municipality or Public Utility Commission of Texas regulated utility, fired with solid, liquid, and/or gaseous fuel, used to produce steam for the purpose of generating electricity.

Wood–Wood, wood residue, bark, or any derivative fuel or residue thereof in any form, including, but not limited to, sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 19, 1993.

TRD-9323203 Lane Hartsock
Deputy Director, Air Quality Planning
Texas Air Control Board

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For further information, please call: (512) 908-1451

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Subchapter B. Combustion at Existing Major Sources

Utility Electric Generation

• 31 TAC §§117.101, 117.103, 117.105, 117.107, 117.109, 117.111, 117.113, 117.115, 117.117, 117.119, 117.121

The new rules are adopted under the Texas Health and Safety Code (Vernon 1990), Texas Clean Air Act, §382.017, which provides TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117.101. Applicability.

(a) The provisions of this undesignated head (relating to Utility Electric Generation) shall apply to utility boilers, steam generators, auxiliary steam boilers, and gas turbines used in an electric power generating system owned or operated by a municipality or a Public Utility Commission of Texas regulated utility located within the Houston/Galveston and Beaumont/Port Arthur ozone nonattainment areas.

(b) The provisions of this undesignated head are applicable for the life of each affected unit within an electric power generating system or until this undesignated head or sections of this title which are applicable to an affected unit are rescinded.

§117.103. Exemptions.

(a) The provisions of §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications) shall not apply during periods of major upset or maintenance under the requirements of §101. 6 of this title (relating to Notification Requirements for Major Upset), §101.7 of this title (relating to Notification Requirements for Maintenance), and §101.11 of this title (relating to Exemptions from Rules and Regulations).

(b) Units exempted from the provisions of this undesignated head (relating to Utility Electric Generation) include the following:

(1) any new units placed into service after November 15, 1992;

(2) any utility boiler, steam generator, or auxiliary steam boiler with an annual heat input less than or equal to $2.2(10^{11})$ (Btu) per year; or

(3) stationary gas turbines, which are:

(A) used solely to power other engines or gas turbines during startups;

(B) used as emergency standby gas turbines or engines and demonstrated to operate less than 850 hours per calendar year; or

(C) peaking gas turbines and operated less than 850 hours per calendar year.

(c) The owner or operator of any utility boiler, steam generator, or auxiliary steam boiler using the exemption of subsection (b)(2) of this section shall install and maintain totalizing fuel meters for each individual unit, as approved by the Executive Director, and record the fuel input for each unit on a calendar year basis. The owner or operator of any engine or turbine using the exemption of subsection (b)(3) of this section shall record the operating time with instrumentation approved by the Executive Director. The owner or operator of any utility boiler, steam generator, auxiliary steam boiler, or stationary gas turbine or engine exempt under the exemptions of subsection (b)(2) and (3) of this section must notify the Executive Director within seven days if the applicable Btu per year (Btu/yr) or hour per year (hr/yr) limit is exceeded. If the Btu/yr or hr/yr limit is exceeded, the exemption shall be permanently withdrawn Within 90 days after loss of the exemption, the owner or operator must submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible but no later than 24 months after exceeding the hr/yr limit. Included with this compliance plan, the owner or operator must submit a schedule of increments of progress for the installation of the required control equipment. This schedule shall be subject to the review and approval of the Executive Director.

§117.105. Emission Specifications

(a) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pound per million (MM) British thermal unit (Btu) heat input on a rolling 24-hour average and 0.20 pound per MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler or steam generator, NO_x emissions in excess of 0.38 pound per MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0 43 pound per MMBtu heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

(c) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler, NO_x emissions in excess of 0.30 pound per MMBtu heat input on a rolling 24-hour averaging period while firing fuel oil only.

(d) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission limits specified in subsections (a)-(c) of this section on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows:

$$\text{Emission Limit} = [a(0.26) + b(0.30)]/(a + b)$$

Where:

a = is the percentage of total heat input from natural gas.

b = is the percentage of total heat input from fuel oil.

(e) Each auxiliary steam boiler which is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations (CFR), Part 60, Subparts D, Db, or Dc shall be limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary boiler subject to an emission specification under this subsection is not subject to the emission specifications of subsection (a) or (c) of this section.

(f) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in MW-hours of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas.

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 30 MW and an annual electric output in MW-hours of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of 65 ppmv at 15% O_2, dry basis, while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hours of less than the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of 0.20 pound per MMBtu heat input while firing natural gas.

(i) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hours of less than the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of 0.30 pound per MMBtu heat input while firing fuel oil.

(j) No person shall allow the discharge into the atmosphere from any unit subject to this undesignated head (relating to Utility Electric Generation), carbon monoxide emissions in excess of 400 ppmv based on a rolling 24-hour averaging period.

(k) No person shall allow the discharge into the atmosphere from any unit subject to this undesignated head, ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(l) The NO_x emission limits specified in subsections (a)-(i) of this section shall apply at all times, except as specified in §117.103 of this title (relating to Exemptions) and §117.107 of this title (relating to Alternative System-Wide Emission Specifications). The emission limits specified in subsections (j) and (k) of this section shall apply at all times, except as specified in §117. 103 of this title.

§117.107. Alternative System-Wide Emission Specifications.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.105 of this title (relating to Emission Specifications) by achieving compliance with a system-wide emission limitation. Any owner or operator who elects to comply with system-wide emission limits shall reduce emissions of NO_x from affected units so that, if all such units were operated at their maximum rated capacity, the system-wide emission rate from all units in the system would not exceed the system-wide emission limit as defined in §117.10 of this title (relating to Definitions), and shall establish enforceable emission limits for each affected unit in the system. A pound per million (MM) Btu emission limit based on a rolling 24-hour averaging period and a pound per MMBtu emission limit based on a 30-day averaging period shall apply to each gas-fired unit in the system. A pound per MMBtu emission limit based on a rolling 24-hour averaging period shall apply to each coal-fired unit in the system.

(b) An owner or operator of any gaseous and liquid fuel-fired utility boiler, steam generator, auxiliary steam boiler, or gas turbine which derives more than 50% of its annual heat input from gaseous fuel shall use only the appropriate gaseous fuel emission limit of §117.105 of this title at maximum rated capacity in calculating the system-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate while firing gas, calculated in accordance with subsection (a) of this section. The owner or operator shall also:

(1) comply with the assigned maximum allowable emission rate while firing natural gas only;

(2) comply with the liquid fuel emission limit of §117.105 of this title while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing allowable emission rate and the liquid fuel emission limit of §117.105 of this title while operating on liquid and gaseous fuel concurrently.

(c) Peaking gas turbines subject to the emission limits of §117.105(h) or (i) of this title and auxiliary steam boilers subject to the emission limits of §117.105(a), (c), (d), or (e) of this title shall comply with those individual emission specifications under this section and shall not be included in the system-wide emission specification. Coal-fired utility boilers or steam generators shall be treated as a separate system, and system averaging for coal-fired utility boilers or steam generators shall be limited to those units under this section.

(d) Solely for purposes of calculating the system-wide emission limit, the allowable mass emission rate for each affected unit shall be calculated from the emission specifications of §117.105 of this title, as follows.

(1) The NO_x emissions rate (in pounds per hour) for each affected utility boiler, steam generator, or auxiliary steam boiler is the product of its maximum rated capacity and its NO_x emission specification of §117.105 of this title.

(2) The NO_x emissions rate (in pounds per hour) for each affected stationary gas turbine is the product of the in-stack NO_x, the turbine manufacturer's rated exhaust flow rate (expressed in pounds per hour at megawatt (MW) rating and International Standards Organization (ISO) flow conditions), and (46/28) (10^{-6});

Where:

$$\text{In-stack } NO_x = NO_x \text{ (allowable)} \times (1 - \%H_2O/100) \times [20.9 - \%O_2(1 - \%H_2O/100)]/5.9$$

Where:

NO_x (allowable) = the applicable NO_x emission specification of §117.105(f) or (g) of this title (expressed in ppmv NO_x at 15% oxygen, dry basis)

$\%H_2O$ = the volume percent water in the stack gases, as calculated at MW rating and ISO flow conditions

$\%O_2$ = the volume percent oxygen in the stack gases on a wet basis, as calculated at the MW rating and ISO flow conditions.

§117.109. Initial Control Plan Procedures. The owner or operator of any major source which has units subject to §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications) shall submit, for the approval of the Executive Director, an initial control plan for installation of nitrogen oxides (NO_x) emissions control equipment to meet the requirements of §117.105 of this title or §117.107 of this title. The Executive Director shall approve the plan if it contains all the information specified in this section. Revisions to the initial control plan shall be submitted with the final control plan. The initial control plan shall be submitted in accordance with the schedule specified in §117.510 of this title (relating to Compliance Schedule For Utility Electric Generation) and shall contain the following:

(1) a list of all combustion units at the source with a maximum rated capacity greater than 5.0 million Btu per hour; all stationary, reciprocating internal combustion which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/ Port Arthur ozone nonattainment area and rated 300 hp or greater; all stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW; to include the maximum rated capacity, anticipated annual heat input capacity factor, the facility identification numbers as submitted to the Emissions Inventory Division of the Texas Air Control Board (TACB), and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable TACB permit for each unit;

(2) identification of all units subject to the emission specifications of §117.105 of this title or §117.107 of this title;

(3) identification of all boilers, and stationary gas turbines with a claimed exemption from the emission specifications of §117.105 of this title or §117.107 of this title and the rule basis for the claimed exemption;

(4) identification of the election to use individual emission limits as specified in §117.105 of this title or the system-wide emission limit specified in §117.107 of this title to achieve compliance with this rule;

(5) a list of units to be controlled and the type of control to be applied for all such units, including an anticipated construction schedule;

(6) a list of any units retired, decommissioned, or shut down and rendered inoperable as a result of compliance with this regulation; and

(7) the basis for calculation of the mass rate of NO_x emissions for each unit to demonstrate that each unit will achieve the NO_x emission rates specified in §117.105 of this title or §117. 107 of this title.

§117.111. Initial Demonstration of Compliance.

(a) All units which are identified in the control plan required by §117.109 of this title (relating to Initial Control Plan Procedures) and are subject to the emission limitations of §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative Plant-Wide Emission Specifications), shall be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions. Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions. Such tests shall be performed in accordance with the schedule specified in §117.510(3) of this title (relating to Compliance Schedule For Utility Electric Generation).

(b) The tests required by subsection (a) of this section shall be used for determination of initial compliance with either the emission limits of §117. 105 of this title or the assigned emission limits of §117.107 of this title, as applicable. Test results shall be reported in the units of the applicable emission limits and averaging periods.

(c) Continuous emissions monitoring systems (CEMS) required by §117.113(a) of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational prior to conducting performance testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(d) Initial compliance with the emission specifications of §117.105 of this title or §117.107 of this title for units operating with CEMS in accordance with §117.113(a) of this title shall be demonstrated using the NO_x CEMS as follows.

(1) To comply with the NO_x emission limit in pound per million (MM) Btu on a rolling 30-day average, NO_x emissions from a unit are monitored for 30 successive unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) To comply with the NO_x emission limit in pound per MMBtu on a rolling 24-hour average, NO_x emissions from a unit are monitored for 24 consecutive operating hours and the 24-hour average emission rate is used to determine compliance with the NO_x emission limit. The 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

(3) To comply with the CO emission limit in parts per million by volume on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission limit. The rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

§117.113. Continuous Demonstration of Compliance.

(a) The owner or operator of each affected unit, as defined in §117.101 of this title (relating to Applicability), except for exempted units listed in §117. 103 of this title (relating to Exemptions); peaking units as defined in §1.1 or §1.2 of Appendix E of 40 Code of Federal Regulations (CFR) Part 75, subject to the monitoring requirements of Appendix E; gas turbines monitored in accordance with subsection (e) of this section; and auxiliary boilers as defined in §117.10 of this title (relating to Definitions), monitored in accordance with subsection (d) of this section, shall install, calibrate, maintain, and operate an in-stack continuous emissions monitoring system (CEMS) to measure nitrogen oxides (NO_x) on an individual basis. The CEMS shall be installed by the time of compliance with the emission limits specified in §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications). Each CEMS shall be capable of measuring the following:

(1) NO_x;

(2) carbon monoxide;

(3) oxygen or carbon dioxide as a diluent; and

(4) exhaust or fuel flow rate.

(b) Any CEMS required by subsection (a) of this section shall be installed, calibrated, maintained, and operated in accordance with 40 CFR, Part 75 or 40 CFR, Part 60, as applicable. The Texas Air Control Board (TACB) Executive Director may approve alternative locations to in-stack monitoring for any affected unit subject to this section.

(c) The owner or operator of each peaking unit as defined in 40 CFR Part 75, Appendix E §1.1 or §1.2, may monitor operating parameters for each unit in accordance with Appendix E and calculate NO_x emission rates based on those procedures or use CEMS in accordance with subsection (a) of this section to monitor NO_x emission rates.

(d) The owner or operator of each auxiliary boiler as defined in §117.10 of this title shall install, calibrate, maintain, and operate a CEMS in accordance with subsection (a) of this section or comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.213 of this title (relating to Continuous Demonstration of Compliance).

(e) The owner or operator of each gas turbine subject to the emission specifications of §117.105 of this title, in lieu of monitoring emissions in accordance with the monitoring requirements of 40 CFR 75, may elect to comply with the following monitoring requirements:

(1) for gas turbines rated less than 30 megawatt or peaking gas turbines (as defined in §117.10 of this title) which use steam or water injection to comply with the emission specifications of §117.105(h) or (i) of this title:

(A) install, calibrate, maintain, and operate a CEMS in compliance with subsection (b) of this section; or

(B) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system shall be accurate to within ± 5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.105 of this title;

(2) for gas turbines subject to the emission specifications of §117.105(f) or (g) of this title, install, calibrate, maintain, and operate a CEMS in compliance with subsection (b) of this section.

(f) After the initial demonstration of compliance required by §117.111 of this title (relating to Initial Demonstration of Compliance), compliance with either §117.105 of this title or §117.107 of this title, as applicable, shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the Executive Director using any TACB compliance method. If compliance with §117.105 of this title is selected, no unit subject to §117.105 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.105 of this title. If compliance with §117.107 of this title is selected, no unit subject to §117.107 of this title shall be operated at an emission rate higher than that approved by the Executive Director pursuant to §117.115(b)(2) of this title (relating to Final Control Plan Procedures).

§117.115. Final Control Plan Procedures.

(a) For sources complying with §117.105 of this title (relating to Emission Specifications), the owner or operator of an affected source shall submit a final control report to show compliance with the requirements of §117.105 of this title by the date specified in §117.510(4) of this title (relating to Compliance Schedule for Utility Electric Generation). The report shall include a list of all affected units showing the method of control of nitrogen oxides (NO_x) emissions for each unit and the results of testing required in §117.111 of this title (relating to Initial Demonstration of Compliance).

(b) For sources complying with §117.107 of this title (relating to Alternative System-Wide Emission Specifications), the owner or operator of an affected source shall submit a final control plan to show attainment of the requirements of §117.107 of this title by the date specified in §117.510(4) of this title. The owner or operator shall:

(1) assign to each affected unit the maximum NO_x emission rate, expressed in units of pound per million Btu heat input on a rolling 24-hour average and rolling 30-day average for gaseous or liquid fuel-firing, and a rolling 24-hour average for coal firing, which are allowable for that unit under the requirements of §117.107 of this title;

(2) submit a list to the Executive Director for approval of the maximum allowable NO_x emission rates identified in paragraph (1) of this subsection and maintain a copy of the approved list for verification of continued compliance with the requirements of §117.107 of this title; and

(3) submit a list summarizing the results of testing each unit in accordance with the requirements of §117.111 of this title.

§117.117. Revision of Final Control Plan. A revised final control plan may be submitted by the owner or operator, along with any required permit applications. Such a plan shall adhere to the emission limits and the final compliance dates of this undesignated head (relating to Utility Electric Generation). The revision of the final control plan shall be subject to the review and approval of the Executive Director.

§117.119. Notification, Recordkeeping, and Reporting Requirements.

(a) For units subject to the exemptions allowed under §117.103(a) of this title (relating to Exemptions), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the Texas Air Control Board (TACB) , United States Environmental Protection Agency (EPA), and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type fuel burned; gross and net energy production in megawatt hours (MW-hr); and the date, time, and duration of the procedure.

(b) The owner or operator of a unit subject to the provisions of §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications) shall submit to the Executive Director written notification, as follows:

(1) verbal notification of the date of any performance testing conducted under §117.111 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) performance evaluation conducted under §117.113 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) The owner or operator of an affected unit shall furnish the Executive Director and any local air pollution control agency having jurisdiction a copy of any performance testing conducted under §117.111 of this title or any CEMS performance evaluation conducted under §117.113 of this title within 60 days after completion of such testing or evaluation.

(d) The owner or operator of a unit required to install a CEMS, continuous operating parameter monitoring system, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.113 of this title shall report in writing to the Executive Director on a quarterly basis any exceedance of the applicable emission limitations in §117.105 of this title or §117.107 of this title and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations, Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period. For gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.113(e)(1)(B) of this title, excess emissions are computed as each one-hour period during which the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial performance test required by §117.111 of this title.

(2) specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the affected unit. The nature and cause of any malfunction (if known) and the corrective action taken or preventative measures adopted;

(3) the date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments;

(4) when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report;

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total unit operating time for the reporting period and the CEMS or steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only

a summary report form (as outlined in the latest edition of the TACB "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the Executive Director of the TACB. If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS or steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) For units subject to the provisions of §117.105 of this title or §117.107 of this title, records of hours of operation and other operating records shall be made and maintained for a period of at least two years. Records shall be available for inspection by the TACB, EPA, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit shall be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or monthly for units exempt from the emission specifications based on annual heat input, or hours of operation per calendar year, and shall include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary boilers);

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) CEMS, continuous operating parameter monitoring system, or steam-to-fuel or water-to-fuel ratio monitoring system data, as applicable, pursuant to §117.113 of this title. The records shall include:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of performance testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, continuous operating parameter monitoring systems, or steam-to-fuel or water-to-fuel ratio monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable.

§117.121. Alternative Case Specific Specifications. Where a person can demonstrate that an affected unit cannot attain the requirements of §117.105 of this title (relating to Emission Specifications), as applicable, the Executive Director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.105 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology. In determining whether to approve alternative emission specifications, the Executive Director may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity. Any person affected by the decision of the Executive Director may appeal to the Board by filing written notice of appeal with the Executive Director within 30 days after the decision. Such appeal is to be taken by written notification to the Executive Director. Section 103.71 of this title (relating to Request for Action by the Board) should be consulted for the method of requesting Board action on the appeal. Executive Director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this undesignated head (relating to Utility Electric Generation).

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 19, 1993.

TRD-9323204 Lane Hartsock
Deputy Director, Air Quality Planning
Texas Air Control Board

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Proposal publication date: November 20, 1992

For further information, please call: (512) 908-1451

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Commercial, Institutional, and Industrial Sources

• 31 TAC §§117.201, 117.203, 117.205, 117.207-117.209, 117.211, 117.213, 117.215, 117.217, 117.219, 117.221

The new rules are adopted under the Texas Health and Safety Code (Vernon 1990), Texas Clean Air Act, §382.017, which provides TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117.201. Applicability. The provisions of this undesignated head (relating to Commercial, Institutional, and Industrial Sources) shall apply to the following units located at any major stationary source of nitrogen oxides (NO_x) located within the Houston/Galveston or Beaumont/Port Arthur ozone nonattainment areas:

(1) commercial, institutional, or industrial boilers and process heaters with a maximum rated capacity of 40 million Btu per hour or greater;

(2) stationary gas turbines with a megawatt (MW) rating of 1.0 MW or greater; and

(3) stationary internal combustion engines which are:

(A) located in the Houston/Galveston ozone nonattainment area with a horsepower (hp) rating of 150 hp or greater; or

(B) located in the Beaumont/Port Arthur ozone nonattainment area with a horsepower rating of 300 hp or greater.

§117.203. Exemptions.

(a) The provisions of §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) shall not apply during periods of major upset or maintenance under the requirements of §101. 6 of this title (relating to Notification Requirements for Major Upset), §101 7 of this title (relating to Notification Requirements for Maintenance), and §101.11 of this title (relating to Exemptions from Rules and Regulations).

(b) Units exempted from the provisions of this undesignated head (relating to Commercial, Institutional, and Industrial Sources) include the following:

(1) any new units placed into service after November 15, 1992;

(2) any commercial, institutional, or industrial boiler or process heater with a maximum rated capacity of less than 40 million (MM) Btu per hour;

(3) any electric utility power generating boiler;

(4) flares, incinerators, fume abaters, sulfur recovery units, and sulfur plant reaction boilers;

(5) dryers, kilns, or ovens used for drying, baking, cooking, calcining, and vitrifying;

(6) stationary gas turbines and engines, which are:

(A) used in research and testing, or used for purposes of performance verification and testing, or used solely to power other engines or gas turbines during start-ups, or operated exclusively for firefighting and/or flood control, or used in response to and during the existence of any officially declared disaster or state of emergency, or used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals, or used as chemical processing gas turbines;

(B) used as emergency standby gas turbines which are demonstrated to operate less than 850 hours per calendar year (low annual capacity factor gas turbines) or engines which are demonstrated to operate less than 850 hours per calendar year (low annual capacity factor engines). The owner or operator of any engine or turbine using this exemption shall record the operating time with an elapsed run time meter; or

(C) used as peaking gas turbines or engines and operated less than 850 hours per calendar year. The owner or operator of any engine or turbine using this exemption shall record the operating time with instrumentation approved by the Executive Director. The owner or operator of any stationary gas turbine or engine exempt under this exemption must notify the Executive Director within seven days if the hour-per-year limit is exceeded. If the hour-per-year limit is exceeded, the exemption shall be permanently withdrawn. Within 90 days after loss of the exemption, the owner or operator must submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible but no later than 24 months after exceeding the hour-per-year limit. Included with this compliance plan, the owner or operator must submit a schedule of increments of progress for the installation of the required control equipment. This schedule shall be subject to the review and approval of the Executive Director;

(7) stationary gas turbines with a megawatt (MW) rating of less than 1. 0 MW; and

(8) stationary internal combustion engines which are:

(A) located in the Houston/Galveston ozone nonattainment area with a horsepower (hp) rating of less than 150 hp, or

(B) located in the Beaumont/Port Arthur ozone nonattainment area with a horsepower rating of less than 300 hp.

§117.205. Emission Specifications.

(a) No person shall allow the discharge of air contaminants into the atmosphere to exceed the emission limits of this section, except as provided in §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications). For units which operate with continuous emission monitors in accordance with §117. 213(b) of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply as the mass of nitrogen oxides (NO_x) emitted per unit of energy input (pound NO_x per million (MM) Btu), on a rolling 30-day average period, or as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average. For units which do not operate with continuous emission monitors, the emission limits shall apply as the mass of NO_x emitted per hour (pounds NO_x per hour) , on a block one-hour average. The mass of NO_x emitted per hour shall be calculated as the product of the unit's maximum rated capacity and its applicable limit (in pound NO_x per MMBtu), as follows.

(1) Each commercial, institutional, or industrial boiler which is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations (CFR), Part 60, Subparts D or Db, shall be limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit as identified in paragraph (2) of this subsection, in which case the more stringent emission limit applies.

(2) Each commercial, institutional, or industrial boiler or process heater operating under a permit issued after March 3, 1982, pursuant to Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and placed into service prior to November 15, 1992, and subject to a NO_x best available control technology review shall be subject to the permitted NO_x limitation, as follows:

(A) the limit explicitly stated in pound NO_x per MMBtu of heat input by permit provision (converted from low heating value to high heating value, as necessary); or

(B) the NO_x emission limit is the limit calculated as the permit Maximum Allowable Emission Rate Table emission limit in pounds per hour, divided by the maximum heat input to the unit in MMBtu per hour (MMBtu/hr), as represented in the permit application. In the event the maximum heat input to the unit is not explicitly stated in the permit application, the rate shall be calculated from Table 6 of the permit application, using the design maximum fuel flow rate and higher heating value of the fuel, or, if neither of these are available, the unit's nameplate heat input.

(3) Each commercial, institutional, or industrial boiler and process heater with a maximum rated capacity greater than or equal to 100.0 MMBtu/hr of heat input, not subject to paragraphs (1) or (2) of this subsection, shall meet the applicable emission limit, as follows:

(A) gas-fired boilers, as follows:

(i) low heat release boilers with no preheated air or preheated air less than 200 degrees Fahrenheit of air preheat, 0.10 pound (lb) NO_x/MMBtu of heat input;

(ii) low heat release boilers with preheated air greater than or equal to 200 degrees Fahrenheit and less than 400 degrees Fahrenheit of air preheat, 0.15 lb NO_x/MMBtu of heat input;

(iii) low heat release boilers with preheated air greater than or equal to 400 degrees Fahrenheit of air preheat, 0.20 lb NO_x/MMBtu of heat input;

(iv) high heat release boilers with no preheated air or preheated air less than 250 degrees Fahrenheit of air preheat, 0.20 lb NO_x/MMBtu of heat input;

(v) high heat release boilers with preheated air greater than or equal to 250 degrees Fahrenheit and less than 500 degrees Fahrenheit of air preheat, 0.24 lb NO_x/MMBtu of heat input; or

(vi) high heat release boilers with preheated air greater than or equal to 500 degrees Fahrenheit of air preheat, 0.28 lb NO_x/MMBtu of heat input;

(B) gas-fired process heaters, based on either air preheat temperature or firebox temperature, as follows:

(i) based on air preheat temperature:

(I) process heaters with preheated air less than 200 degrees Fahrenheit of air preheat, 0.10 lb NO_x/MMBtu of heat input;

(II) process heaters with preheated air greater than or equal to 200 degrees Fahrenheit and less than 400 degrees Fahrenheit of air preheat, 0.13 lb NO_x/MMBtu of heat input; or

(III) process heaters with preheated air greater than or equal to 400 degrees Fahrenheit of air preheat, 0.18 lb NO_x/MMBtu of heat input;

(ii) based on firebox temperature:

(I) process heaters with a firebox temperature less than 1,400 degrees Fahrenheit, 0.10 lb NO_x/MMBtu of heat input;

(II) process heaters with a firebox temperature greater than or equal to 1,400 degrees Fahrenheit and less than 1,800 degrees Fahrenheit, 0.125 lb NO_x/MMBtu of heat input; or

(III) process heaters with a firebox temperature greater than or equal to 1,800 degrees Fahrenheit, 0.15 lb NO_x/MMBtu of heat input;

(C) liquid fuel-fired boilers and process heaters, 0.30 lb NO_x/MMBtu of heat input;

(D) wood fuel-fired boilers and process heaters, 0.30 lb NO_x/MMBtu of heat input;

(E) any unit operated with a combination of gaseous, liquid, or wood fuel, a variable emission limit calculated as the heat-input weighted average of the applicable emission limits of this paragraph.

(4) Any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, shall use a multiplier of 1.25 times the appropriate emission limit in this subsection, for that eight-hour period. The total hydrogen volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of hydrogen in the fuel supply.

(b) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 10.0 MW, emissions in excess of a block one-hour average concentration of 42 parts per million by volume (ppmv) NO_x and 132 ppmv carbon monoxide (CO) at 15% oxygen, dry basis.

(c) No person shall allow the discharge into the atmosphere from any gas-fired, rich-burn, stationary, reciprocating internal combustion engine, emissions in excess of a block one-hour average of 2.0 grams NO_x per horsepower hour (g NO_x/hp-hr) and 3.0 g CO/hp-hr for engines which are:

(1) rated 150 hp or greater and located in the Houston/Galveston ozone nonattainment area; or

(2) rated 300 hp or greater and located in the Beaumont/Port Arthur ozone nonattainment area.

(d) No person shall allow the discharge into the atmosphere from any boiler or process heater subject to NO_x emission specifications in subsection (a) of this section, CO in excess of 400 ppmv based on a block one-hour average.

(e) No person shall allow the discharge into the atmosphere from any unit subject to a NO_x emission limit in this undesignated head (relating to Commercial, Institutional, and Industrial Sources), ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(f) Units exempted from the emissions specifications of this section include the following:

(1) any commercial, institutional, or industrial boiler or process heater with a maximum rated capacity less than 100 MMBtu/hr;

(2) any low annual capacity factor boiler or process heater as defined in §117.10 of this title (relating to Definitions);

(3) boilers and industrial furnaces which are regulated as existing facilities by the United States Environmental Protection Agency at 40 CFR Part 266, Subpart H;

(4) fluid catalytic cracking units (including CO boilers);

(5) supplemental waste heat recovery units used in turbine exhaust ducts;

(6) any lean-burn, stationary, reciprocating internal combustion engine; and

(7) any stationary gas turbine with a MW rating less than 10.0 MW.

(g) The NO_x emission limits specified in subsections (a)-(c) of this section shall apply at all times except as specified in §117.203 of this title (relating to Exemptions) and §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications). The CO emission limits specified in subsections (b), (c), and (d) of this section and the ammonia emission limits specified in subsection (e) of this section shall apply at all times, except as specified in §117.203 of this title.

§117.207. Alternative Plant-Wide Emission Specifications.

(a) An owner or operator may achieve compliance with the emission limits of §117.205 of this title (relating to Emission Specifications) by achieving equivalent nitrogen oxides (NO_x) emission reductions obtained by compliance with a plant-wide emission limitation. Any owner or operator who elects to comply with a plant-wide emission limit shall reduce emissions of NO_x from affected units so that if all such units were operated at their maximum rated capacity, the plant-wide emission rate of NO_x from these units would not exceed the plant-wide emission limit as defined in §117.10 of this title (relating to Definitions) and shall establish an enforceable emission limit for each affected unit at the source. For units which operate with continuous emission monitors in accordance with §117.213(b) of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply as the mass of NO_x emitted per unit of energy input (pound NO_x per million (MM) Btu), on a rolling 30-day average period, or as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average. For units which do not operate with continuous emission monitors, the emission limits shall apply as the mass of NO_x emitted per hour (pounds NO_x per hour), on a block one-hour average.

(b) Units exempted from emission specifications in accordance with §117.205(f) of this title are also exempt under this section and shall not be included in the plant-wide emission limit, except as provided in subsection (f) of this section.

(c) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from gaseous fuel shall use only the appropriate gaseous fuel emission limit of §117.205 of this title at maximum rated capacity in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate while firing gas, calculated in accordance with subsection (a) of this section. The owner or operator shall also:

(1) comply with the assigned maximum allowable emission rate while firing gas only;

(2) comply with the liquid fuel emission limit of §117.205 of this title while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing allowable emission rate and the liquid fuel emission limit of §117.205 of this title while operating on liquid and gaseous fuel concurrently.

(d) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from liquid fuel shall use a heat input weighted average of the appropriate gaseous and liquid fuel emission specifications of §117 205 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(e) An owner or operator of any unit operated with a combination of gaseous (or liquid) and solid fuels shall use a heat input weighted average of the appropriate emission specifications of §117.205 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(f) The owner or operator of exempted units as defined in §117.205(f) of this title may elect to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications as defined in this section. The equipment classes which may be included in the alternative plant-wide emission specifications as an entire population of units at the major source include the following: fluid catalytic cracking unit carbon monoxide (CO) boilers; lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 horsepower (hp) or greater; boilers, steam generators, or process heaters with a maximum rated capacity of greater than or equal to 40 million Btu per hour (MMBtu/hr) and less than 100 MMBtu/hr; and stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW and less than 10.0 MW. Low annual capacity factor boilers or process heaters and low annual capacity factor gas turbines or engines as defined in §117.10 of this title and §117.203(b)(6)(B) of this title are not to be considered as part of that class of equipment. The individual emission limits that are to be used in calculating the alternative plant-wide emission specifications are, as follows:

(1) fluid catalytic cracking unit CO boilers, 50% NO_x reduction across the inlet of the CO boiler to the outlet of the CO boiler, with the outlet concentration in parts per million by volume converted into a pound (lb) NO_x/MMBtu of heat input;

(2) lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 hp or greater, 5.0 grams NO_x/horsepower-hour (g NO_x/hp-hr) under all operating conditions;

(3) boilers, steam generators, or process heaters with a maximum rated capacity of greater than or equal to 40 MMBtu/hr and less than 100 MMBtu/hr, the emission specifications in §117.205(a) of this title for the applicable type of unit; and

(4) stationary gas turbines with a MW rating of greater than or equal to 1.0 MW and less than 10 0 MW, 42 parts ppmv NO_x at 15% oxygen (O_2), dry basis.

(g) Solely for the purposes of calculating the plant-wide emission limit, the allowable mass emission rate for each affected unit shall be calculated from the emission specifications of §117.205 of this title, as follows.

(1) The NO_x emission rate (in lbs per hour) for each affected boiler and process heater is the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title.

(2) The NO_x emission rate (in lbs per hour) for each affected stationary internal combustion engine is the product of the applicable NO_x emission specification of §117.205 of this title (expressed in g/hp-hr) and the engine manufacturer's rated heat input (expressed in MMBtu/hr) at the engine's hp rating; divided by the product of the engine manufacturer's rated heat rate (expressed in Btu/hp-hr) at the engine's hp rating and $454(10^{6})$.

(3) The NO_x emission rate (in lbs per hour) for each affected stationary gas turbine is the product of the in-stack NO_x, the turbine manufacturer's rated exhaust flow rate (expressed in lbs per hour at MW rating and International Standards Organization (ISO) flow conditions) and $(46/28)(10^{-6})$:

Where:

$$\text{In-stack } NO_x = NO_x(\text{allowable}) \times (1 - \%H_2O/100) \times [20.9 - \%O_2(1 - \%H_2O/100)]/5.9$$

Where:

NO_x (allowable) = the applicable NO_x emission specification of §117.205 of this title (expressed in ppmv NO_x at 15% O_2, dry basis)

$\%H_2O$ = the volume percent of water in the stack gases, as calculated at MW rating and ISO flow conditions

$\%O_2$ = the volume percent of O_2 in the stack gases on a wet basis, as calculated at MW rating and ISO flow conditions.

(4) The NO_x emission rate (in lbs per hour) for each affected gas-fired boiler and process heater firing gaseous fuel which contains more than 50% hydrogen (H_2) by volume, over an annual basis, in which the fuel gas composition is sampled and analyzed every three hours, may use a multiplier of 1.25 times the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title. Double application of the H_2 content multiplier using this paragraph and §117.205(a)(4) of this title is not allowed.

(h) The owner or operator of any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% H_2 by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, may use a multiplier of 1.25 times the emission limit assigned to the unit in this section for that eight-hour period, not applicable to units under subsection (g)(4) of this section. The total H_2 volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of H_2 in the fuel supply.

§117.208. Operating Requirements.

(a) Except during major upset or maintenance as referenced in §101.6 of this title (relating to Notification Requirements for Major Upset), §101.7 of this title (relating to Notification Requirements for Maintenance), and §101.11 of this title (relating to Exemptions from Rules and Regulations), the owner or operator shall operate any unit subject to the emission limitations of §117.205 of this title (relating to Emission Specifications) in compliance with those limitations.

(b) The owner or operator shall operate any unit subject to the plant-wide emission limit of §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) such that the assigned maximum nitrogen oxides (NO_x) emission rate for each unit expressed in units of the applicable emission limit and averaging period, is in accordance with the list approved by the Executive Director pursuant to §117.215 of this title (relating to Final Control Plan Procedures).

(c) All units subject to the emission limitations of §117 205 of this title or §117.207 of this title shall be operated so as to minimize NO_x emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

(1) Each boiler shall be operated with oxygen (O_2) or carbon monoxide (CO) trim (or both)

(2) Each boiler and process heater controlled with forced flue gas recirculation (FGR) to reduce NO_x emissions shall be operated such that the proportional design rate of FGR is maintained, consistent with combustion stability, over the operating range.

(3) Each boiler and process heater controlled with induced draft FGR to reduce NO_x emissions shall be operated such that the operation of FGR over the operating range is not restricted by artificial means.

(4) Each unit controlled with steam or water injection shall be operated such that injection rates are maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity (corrected to 15% O_2 on a dry basis for gas turbines).

(5) Each unit controlled with post combustion control techniques shall be operated such that the reducing agent injection rate is maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity.

(6) Each stationary internal combustion engine controlled with nonselective catalytic reduction shall be equipped with an automatic air-fuel ratio (AFR) controller which operates on exhaust O_2 or CO control and maintains AFR in the range required to meet the engine's applicable emission limits.

(7) Each stationary internal combustion engine shall be checked for proper operation of the engine by recorded measurements of NO_x and CO emissions at least quarterly and as soon as practicable after each occurrence of engine maintenance which may reasonably be expected to increase emissions, O_2 sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be acceptable for this documentation.

§117 209. Initial Control Plan Procedures. The owner or operator of any major source which has units subject to §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) shall submit, for the approval of the Executive Director, an initial control plan for installation of nitrogen oxides (NO_x) emissions control equipment to meet the requirements of §117 205 of this title or §117.207 of this title. The Executive Director shall approve the plan if it contains all the information specified in this section. Revisions to the initial control plan shall be submitted with the final control plan. The initial control plan shall be submitted in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources) and shall contain the following:

(1) a list of all combustion units at the source with a maximum rated capacity greater than 5.0 million Btu per hour; all stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater; all stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW; to include the maximum rated capacity, anticipated annual capacity factor, the facility identification numbers as submitted to the Emissions Inventory Division of the Texas Air Control Board (TACB), and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable TACB permit for each unit,

(2) identification of all units subject to the emission specifications of §117.205 of this title or §117 207 of this title;

(3) identification of all boilers, process heaters, stationary gas turbines, or engines with a claimed exemption from the emission specifications of §117.205 of this title or §117.207 of this title and the rule basis for the claimed exemption;

(4) identification of the election to use individual emission limits as specified in §117.205 of this title or the plant-wide emission limit specified in §117.207 of this title to achieve compliance with this rule;

(5) a list of units to be controlled and the type of control to be applied for all such units, including an anticipated construction schedule;

(6) a list of any units retired, decommissioned, or shutdown and rendered inoperable as a result of compliance with this regulation,

(7) the basis for calculation of the rate of NO_x emissions for each unit to demonstrate that each unit will achieve the NO_x emission rates specified in §117 205 of this title or §117.207 of this title For fluid catalytic cracking unit carbon monoxide (CO) boilers, the basis for calculation of the pound NO_x per million Btu (lb NO_x/MMBtu) rate for each unit shall include the following:

(A) the calculation of the CO boiler heat input;

(B) the calculation of the appropriate CO boiler volumetric inlet and exhaust flowrates; and

(C) the calculation of the CO boiler lb NO_x/MMBtu emission rate;

(8) previous testing documentation for any claimed test waiver as allowed by §117.211(e) of this title (relating to Initial Demonstration of Compliance); and

(9) results of emissions testing using portable analyzers or, as available, performance testing conducted in accordance with §117.211(f) or (g) of this title for each unit subject to the testing requirements of §117.211 of this title.

§117.211. Initial Demonstration of Compliance.

(a) All units which are identified in the control plan required by §117.209 of this title (relating to Initial Control Plan Procedures) and are subject to the emission limitations of §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), shall be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions while firing gaseous fuel (and as applicable, hydrogen (H_2) fuel for units which may fire more than 50% H_2 by volume, and liquid fuel). Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions. Performance testing of these units shall be performed in accordance with the schedule specified in §117.520(2) of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources).

(b) The performance tests required by subsection (a) of this section shall use the test methods referenced in subsection (f) or (g) of this section and shall be used for determination of initial compliance with either the emission limits of §117.205 of this title or the assigned emission limits of §117.207 of this title, as applicable. Test results shall be reported in the units of the applicable emission limits and averaging periods.

(c) The units listed in this subsection shall be tested for NO_x, CO, and O_2 emissions while firing gaseous fuel (and as applicable, H_2 fuel for units which may fire more than 50% H_2 by volume) and/or liquid fuel at the maximum rated capacity or as near thereto as practicable. Testing using portable analyzers is acceptable for the units listed in this subsection. The testing shall be performed in accordance with the schedule specified in §117.520(1) of this title. The units listed are as follows:

(1) process heaters and boilers with a maximum rated capacity greater than or equal to 40.0 million Btu per hour (MMBtu/hr) and less than 100.0 MMBtu/hr, except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title (relating to Definitions);

(2) boilers and industrial furnaces with a maximum rated capacity greater than or equal to 40.0 MMBtu/hr which are regulated as existing facilities by the United States Environmental Protection Agency (EPA) at 40 Code of Federal Regulations (CFR), Part 266, Subpart H, except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title;

(3) fluid catalytic cracking units with a maximum rated capacity greater than or equal to 40 MMBtu/hr;

(4) gas turbine supplemental waste heat recovery units with a maximum rated fired capacity greater than or equal to 40 MMBtu/hr, except for low annual capacity factor gas turbine supplemental waste heat recovery units as defined in §117.10 of this title;

(5) stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW and less than 10.0 MW, except for low annual capacity factor gas turbines as defined in §117.203(b)(6)(B) of this title (relating to Exemptions), or peaking gas turbines as defined in §117.203(b)(6)(C) of this title; and

(6) lean-burn, gas-fired, stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater, except for low annual capacity factor engines as defined in §117.203(b)(6)(B) of this title, or peaking engines as defined in §117 203(b)(6)(C) of this title.

(d) Any continuous emissions monitoring system (CEMS) required by §117.213(b) of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational prior to conducting performance testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(e) Testing conducted prior to the effective date of this rule may be used to demonstrate compliance with the standards specified in §117.205 of this title or §117.207 of this title or to satisfy the additional testing requirements of subsection (c) of this section, if the owner or operator of an affected facility demonstrates to the Executive Director that the prior performance testing at least meets the requirements of subsections (a), (b), (c), (d), (f), and (g) of this section. The Executive Director reserves the right to request performance testing or CEMS performance evaluation at any time.

(f) Compliance with the emission specifications of §117.205 of this title or §117.207 of this title for units operating without CEMS shall be demonstrated while operating at the maximum rated capacity, or as near thereto as practicable, by application of the following test methods:

(1) Test method 7E or 20 (40 CFR, Part 60, Appendix A) for NO_x;

(2) Test Method 10, 10A, or 10B (40 CFR 60, Appendix A) for CO;

(3) Test Method 3A or 20 (40 CFR 60, Appendix A) for O_2;

(4) Test Method 2 or 19 (40 CFR 60, Appendix A) for exhaust gas flow; and

(5) American Society of Testing and Materials (ASTM) Method D-1945-81, ASTM Method D-3588-81, or ASTM Method D-2650-83 for fuel composition; or

(6) EPA approved alternate test methods or minor modifications to these test methods as approved by the Executive Director.

(g) Initial compliance with the emission specifications of §117.205 of this title or §117 207 of this title for units operating with CEMS in accordance with 117.213(b) of this title shall be demonstrated using the CEMS as follows.

(1) For units complying with a NO_x emission limit in pound per MMBtu on a rolling 30-day average, NO_x emissions from the unit are monitored for 30 successive unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period

(2) For units complying with a NO_x emission limit in pounds per hour, block one-hour average, any one-hour period after CEMS certification testing required in §117.213(b) of this title is used to determine compliance with the NO_x emission limit

(3) For units complying with a CO emission limit, block one-hour average, any one-hour period after CEMS certifica-

tion testing required in §117.213(b) of this title is used to determine compliance with the CO emission limit

(h) Testing with portable analyzers may be used to satisfy the emissions test requirements for units listed in subsection (c) of this section, and for providing initial compliance plan information for all units which are subject to emission limits. The information shall be provided in accordance with the schedule specified for submission of the initial control plan in §117.520 of this title.

§117.213. Continuous Demonstration of Compliance.

(a) The owner or operator of units listed in this subsection and subject to the provisions of this undesignated head (relating to Commercial, Institutional, and Industrial Sources) shall install, calibrate, maintain, and operate an oxygen (O_2) monitor to measure exhaust stack O_2 concentration and a totalizing fuel flow meter to measure the fuel usage. The O_2 monitors and totalizing fuel flow meters shall be installed by the time of compliance with the emission limits specified in §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) for the following units:

(1) each commercial, institutional, and industrial boiler with a rated heat input greater than or equal to 100 million Btu per hour (MMBtu/hr) and less than 250 MMBtu/hr and an annual heat input greater than 2. $2(10^{11})$ Btu per year (Btu/yr); and

(2) each process heater with a rated heat input greater than or equal to 100 MMBtu/hr and less than 200 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr.

(b) The owner or operator of units listed in this subsection and subject to the provisions of this undesignated head shall install, calibrate, maintain, and operate a continuous exhaust NO_x monitor, a carbon monoxide (CO) monitor, an O_2 (or carbon dioxide) diluent monitor, and a totalizing fuel flow meter. The required continuous emissions monitoring systems (CEMS) and fuel flow meters will be used to measure NO_x, CO, and O_2 emissions for each affected unit. One CEMS may be used to monitor up to three units. Any CEMS shall meet all the requirements of 40 Code of Federal Regulations (CFR), Part 60, §60.13; 40 CFR 60, Appendix B, Performance Specification 2 and 3, and quality assurance procedures of 40 CFR 60, Appendix F, Procedure 1, Section 5.1.2, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5.1.2. The CEMS shall be subject to the approval of the Executive Director under any permit issued pursuant to Title V of the 1990 Federal Clean Air Act (FCAA) Amendments.

(1) The CEMS shall be installed by the time of compliance with the emission limits specified in §117.205 of this title or §117.207 of this title for the following units:

(A) each commercial, institutional, and industrial boiler with a rated heat input greater than or equal to 250 MMBtu/hr and an annual heat input greater than 2. $2(10^{11})$ Btu/yr;

(B) each process heater with a rated heat input greater than or equal to 200 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr;

(C) each stationary gas turbine with a megawatt (MW) rating greater than 30 MW operated more than 850 hours per year;

(D) each unit which uses a chemical reagent for reduction of NO_x; and

(E) each unit for which the owner or operator elects to comply with the NO_x emission specifications of §117.205 of this title or §117.207 of this title using a pound per MMBtu limit on a 30-day rolling average.

(2) The units listed in §117.205(f)(3)-(5) of this title are not required to install CEMS under this subsection.

(c) In addition to the totalizing fuel flow meters specified in subsections (a) and (b) of this section, the owner or operator shall install and maintain totalizing fuel flow meters on an individual unit basis on the following units:

(1) process heaters and commercial, institutional, and industrial boilers with a rated heat input greater than or equal to 40.0 MMBtu/hr and less than 100.0 MMBtu/hr;

(2) low annual capacity factor boilers and process heaters as defined in §117.10 of this title (relating to Definitions) ;

(3) lean-burn, stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater, and

(4) stationary gas turbines with a MW rating greater than or equal to 1.0 MW or less than 10.0 MW.

(d) The owner or operator of any stationary gas engine subject to the emission specifications of §117.205 of this title or §117.207 of this title shall install and maintain a totalizing fuel flow meter and perform biennial stack testing of engine emissions of NO_x and CO, measured in accordance with the methods specified in §117.211(f) of this title (relating to Initial Demonstration of Compliance). In lieu of performing stack sampling on a biennial calendar basis, an owner or operator may elect to install and operate an elapsed operating time meter and shall test the engine within 15,000 hours of engine operation after the previous emission test. The owner or operator who elects to test on an operating hour schedule shall submit, in writing, to the Texas Air Control Board and any local air pollution agency having jurisdiction, biennially after the initial demonstration of compliance, documentation of the actual recorded hours of engine operation since the previous emission test, and an estimate of the date of the next required sampling.

(e) The owner or operator of any stationary gas turbine rated less than 30 MW using steam or water injection to comply with the emission specifications of §117.205 of this title or §117. 207 of this title shall either

(1) install, calibrate, maintain, and operate a CEMS in compliance with subsection (b) of this section; or

(2) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system shall be accurate to within ± 5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.205 of this title or §117.207 of this title.

(f) The owner or operator of any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% H_2 by volume, shall sample, analyze, and record every three hours the fuel gas composition to comply with the emission specifications of §117.205 of this title or §117.207 of this title. The total H_2 volume flow in all gaseous fuel streams to the unit will be divided by the total gaseous volume flow to determine the volume percent of H_2 in the fuel supply to the unit. Fuel gas analysis shall be tested according to American Society of Testing and Materials (ASTM) Method D-1945-81 or ASTM Method D-2650-83, or other methods which are demonstrated to the satisfaction of the Executive Director to be equivalent. A gaseous fuel stream containing 99% H_2 by volume or greater may use the following procedure to be exempted from the sampling and analysis requirements of this subsection.

(1) A fuel gas analysis must be performed initially using one of the test methods in this subsection to demonstrate that the gaseous fuel stream is 99% H_2 by volume or greater.

(2) The process flow diagram of the process unit which is the source of the H_2 shall be supplied to the Texas Air Control Board (TACB) to illustrate the source and supply of the hydrogen stream.

(3) The owner or operator shall certify that the gaseous fuel stream containing H_2 will continuously remain, as a minimum, at 99% H_2 by volume or greater during its use as a fuel to the combustion unit.

(g) After the initial demonstration of compliance required by §117.211 of this title, compliance with either §117.205 of this title or §117.207 of this title, as applicable, shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the Executive Director using any TACB compliance method.

(h) If compliance with §117.205 of this title is selected, no unit subject to §117.205 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.205 of this title. If compliance with §117.207 of this title is selected, no unit subject to §117.207 of this title shall be operated at an emission rate higher than that approved by the Executive Director pursuant to §117.215(b)(2) of this title (relating to Final Control Plan Procedures).

(i) The owner or operator of any low annual capacity factor boiler or process heater as defined in §117.10 of this title must notify the Executive Director within seven days if the Btu/yr limit is exceeded. If the Btu/yr limit is exceeded, the exemption from the emission specifications of §117.205(a)(3) of this title shall be permanently withdrawn. Within 30 days after loss of the exemption, the owner or operator must submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible, but no later than 24 months after exceeding the Btu/yr limit. Included with this compliance plan, the owner or operator must submit a schedule of increments of progress for the installation of the required control equipment. This schedule shall be subject to the review and approval of the Executive Director.

§117.215. Final Control Plan Procedures.

(a) For sources complying with §117.205 of this title (relating to Emission Specifications), the owner or operator of an affected source shall submit a final control report to show compliance with the requirements of §117.205 of this title by the date specified in §117.520(4) of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources). The report shall include a list of all affected units showing the method of control of nitrogen oxides (NO_x) emissions for each unit and the results of testing required in §117.211 of this title (relating to Initial Demonstration of Compliance).

(b) For sources complying with §117. 207 of this title (relating to Alternative Plant-Wide Emission Specifications), the owner or operator of an affected source shall submit a final control plan to show attainment of the requirements of §117.207 of this title by the date specified in §117 520(4) of this title. The owner or operator shall.

(1) assign to each affected unit the maximum allowable NO_x emission rate in pound per million Btu (rolling 30-day average), or in pounds per hour (block one-hour average) while firing gaseous or liquid fuel, which are allowable for that unit under the requirements of §117.207 of this title;

(2) submit a list to the Executive Director for approval of the maximum allowable NO_x emission rates identified in paragraph (1) of this subsection and maintain a copy of the approved list for verification of continued compliance with the requirements of §117.207 of this title; and

(3) submit a list summarizing the results of testing of each unit at maximum rated capacity, in accordance with the requirements of §117.211 of this title.

§117.217. Revision of Final Control Plan. A revised final control plan may be submitted by the owner or operator, along with any required permit applications. Such a plan shall adhere to the emission limits and the final compliance dates of this undesignated head (relating to Commercial, Institutional, and Industrial Sources). New units, including functionally identical replacement units, shall not be incorporated into the plan. The revision of the final control plan shall be subject to the review and approval of the Executive Director.

§117.219. Notification, Recordkeeping, and Reporting Requirements.

(a) For units subject to the exemptions allowed under §117.203(a) of this title (relating to Exemptions), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the Texas Air Control Board (TACB) , United States Environmental Protection Agency (EPA), and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type fuel burned; and the date, time, and duration of the procedure.

(b) The owner or operator of an affected source shall submit to the Executive Director written notification, as follows:

(1) verbal notification of the date of any performance testing conducted under §117.211 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) performance evaluation conducted under §117.213 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) The owner or operator of an affected unit shall furnish the Executive Director and any local air pollution control agency having jurisdiction a copy of any performance testing conducted under §117.211 of this title or any CEMS performance evaluation conducted under §117.213 of this title, within 60 days after completion of such testing or evaluation. For purposes of demonstrating compliance with §117. 520 of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources), such results shall be submitted no later than 30 days before the final compliance date specified in §117 520 of this title

(d) The owner or operator of a unit required to install a CEMS or water-to-fuel or steam-to-fuel ratio monitoring system under §117.213 of this title shall report in writing to the Executive Director on a quarterly basis any exceedance of the applicable emission limitations in §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) and the monitoring system performance All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations, Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period. For gas turbines using steam-to-fuel or water-to-fuel ratio monitor-

ing to demonstrate compliance in accordance with §117.213(e)(2) of this title, excess emissions are computed as each one-hour period during which the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial performance test required by §117.211 of this title;

(2) specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the affected unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;

(3) the date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments;

(4) when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report;

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total unit operating time for the reporting period and the CEMS or water-to-fuel or steam-to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only a summary report form (as outlined in the latest edition of the TACB "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the Executive Director of the TACB. If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS or water-to-fuel or steam-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) The owner or operator of any rich-burn engine subject to the emission limitations in §117.205 of this title or §117.207 of this title shall report in writing to the Executive Director on a quarterly basis any excess emissions and the air-fuel ratio monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) the magnitude of excess emissions (based on the quarterly emission checks of §117.208(c)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.213(d) of this title), computed in pounds per hour and grams per horsepower hour, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the engine operating time during the reporting period;

(2) specific identification, to the extent feasible, of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the engine, catalytic converter, or air-fuel ratio controller, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted

(f) The owner or operator of an affected unit shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and fuel usage rates. Such records shall be kept for a period of at least two years and shall be made available upon request by authorized representatives of the TACB, EPA, or local air pollution control agencies having jurisdiction. The emission monitoring (as applicable) and fuel usage records for each unit shall be recorded and maintained:

(1) on an hourly basis for units complying with an emission limit enforced on a block one-hour average;

(2) on a daily basis for units complying with an emission limit enforced on a rolling 30-day basis; and

(3) on a monthly basis for units exempt from the emission specifications based on annual heat input or hours of operation per calendar year.

§117.221. Alternative Case Specific Specifications. Where a person can demonstrate that an affected unit cannot attain the requirements of §117.205 of this title (relating to Emission Specifications), as applicable, the Executive Director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.205 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology. In determining whether to approve alternative emission specifications, the Executive Director may take into consideration the ability of the plant at which the unit is located to meet emission specifications through plant-wide averaging at maximum capacity Any person affected by the decision of the Executive Director may appeal to the Board by filing written notice of appeal with the Executive Director within 30 days after the decision. Such appeal is to be taken by written notification to the Executive Director. Section 103.71 of this title (relating to Request for Action by the Board) should be consulted for the method of requesting Board action on the appeal. Executive Director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this undesignated head (relating to Commercial, Institutional, and Industrial Sources).

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

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TRD-9323206 Lane Hartsock
Deputy Director, Air Quality Planning
Texas Air Control Board

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For further information, please call (512) 908-1451

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Subchapter C. Acid Manufacturing

Adipic Acid Manufacturing

• 31 TAC §§117.301, 117.305, 117.309, 117.311, 117.313, 117.319, 117.321

The new rules are adopted under the Texas Health and Safety Code (Vernon 1990), Texas Clean Air Act, §382.017, which provides TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117.305. Emission Specifications. No person may allow emissions of nitrogen oxides, calculated as nitrogen dioxide, from the absorber of any adipic acid production unit to exceed 2.5 pounds per ton of adipic acid produced, on a 24-hour rolling average.

§117.309. Control Plan Procedures. Any person affected by this undesignated head (relating to Adipic Acid Manufacturing) shall submit a control plan to the Executive Director on the compliance status of all required emission controls and monitoring systems by April 1, 1994. The Executive Director shall approve the plan if it contains all the information specified in this section. Revisions to the control plan shall be submitted to the Executive Director for approval. The control plan shall provide a detailed description of the method to be

followed to achieve compliance, specifying the anticipated dates by which the following steps will be taken:

(1) dates by which contracts for emission control and monitoring systems will be awarded or dates by which orders will be issued for the purchase of component parts to accomplish emission control or process modification;

(2) date of initiation of on-site construction or installation of emission control equipment or process modification;

(3) date by which on-site construction or installation of emission control equipment or process modification is to be completed; and

(4) date by which final compliance is to be achieved.

§117.313. Continuous Demonstration of Compliance.

(a) The owner or operator of any facility subject to the provisions of this undesignated head (relating to Adipic Acid Manufacturing) shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides (NO_x) from the absorber.

(b) Any CEMS installed subject to subsection (a) of this section shall meet all requirements of 40 Code of Federal Regulations (CFR), Part 60, §60. 13; 40 CFR 60, Appendix B, Performance Specification 2; and quality assurance procedures of 40 CFR 60, Appendix F, Procedure 1, Section 5.1.2, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5.1.2.

(c) The owner or operator of an affected facility shall establish a conversion factor for the purpose of converting monitoring data into units of the emission standard (in pounds NO_x per ton of acid produced) as specified in 40 CFR 60, Subpart G, §60.73(b). NO_x emissions data recorded by the CEMS shall be represented in terms of both parts per million by volume and pounds NO_x per ton of acid produced.

(d) After the initial demonstration of compliance required by §117.311 of this title (relating to Initial Demonstration of Compliance), compliance with §117.305 of this title (relating to Emission Specifications) shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the Executive Director using any Texas Air Control Board compliance method.

§117.319. Notification, Recordkeeping, and Reporting Requirements.

(a) The owner or operator of an affected facility shall submit to the Executive Director written notification, as follows:

(1) verbal notification of the date of any continuous emissions monitoring systems (CEMS) performance evaluation conducted under §117.313(b) of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any performance testing conducted under §117.311 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(b) The owner or operator of an affected facility shall furnish the Executive Director and any local air pollution control agency having jurisdiction a copy of any CEMS performance evaluation conducted under §117.313 of this title, or any performance testing conducted under §117.311 of this title, within 60 days after completion of such evaluation or testing. For purposes of demonstrating compliance with §117.530 of this title (relating to Compliance Schedules For Nitric Acid and Adipic Acid Manufacturing Sources), such results shall be submitted no later than 30 days before the final compliance date specified in §117.530 of this title.

(c) the owner or operator of an affected facility shall report in writing to the Executive Director on a quarterly basis all periods of excess emissions, defined as any 24-hour period during which the average nitrogen oxides (NO_x) emissions (arithmetic average of 24 contiguous one-hour periods) exceed the emission limitation in §117.305 of this title (relating to Emission Specifications) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations, Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period;

(2) specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the affected unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;

(3) the date and time identifying each period during which the CEMS was inoperative, except for zero and span checks and the nature of the system repairs or adjustments;

(4) when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report;

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total operating time for the reporting period and the CEMS downtime for the reporting period is less than 5. 0% of the total operating time for the reporting period, only a summary report form (as outlined in the latest edition of the Texas Air Control Board (TACB) "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the Executive Director of the TACB If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(d) The owner or operator of an affected facility shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and daily production rates. Such records shall be kept for a period of at least two years and shall be made available upon request by authorized representatives of TACB, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction.

§117.321. Alternative Case Specific Specifications. Where a person can demonstrate that an affected unit cannot attain the requirements of §117.305 of this title (relating to Emission Specifications), as applicable, the Executive Director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.305 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology. Any person affected by the decision of the Executive Director may appeal to the Board by filing written notice of appeal with the Executive Director within 30 days after the decision. Such appeal is to be taken by written notification to the Executive Director. Section 103.71 of this title (relating to Request for Action by the Board) should be consulted

for the method of requesting Board action on the appeal Executive Director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this undesignated head (relating to Adipic Acid Manufacturing).

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

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Deputy Director, Air Quality Planning
Texas Air Control Board

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Nitric Acid Manufacturing

• 31 TAC §§117.401, 117.405, 117.409, 117.411, 117.413, 117.419, 117.421

The new rules are adopted under the Texas Health and Safety Code (Vernon 1990), Texas Clean Air Act, §382.017, which provides TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA

§117.405. Emission Specifications. No person may allow emissions of nitrogen oxides, calculated as nitrogen dioxide, from the absorber of any nitric acid production unit to exceed 2 0 pounds per ton of nitric acid produced, the production being expressed as 100% nitric acid, on a 24-hour rolling average.

§117.409. Control Plan Procedures. Any person affected by this undesignated head (relating to Nitric Acid Manufacturing) shall submit a control plan to the Executive Director on the compliance status of all required emission controls and monitoring systems by April 1, 1994. The Executive Director shall approve the plan if it contains all the information specified in this section. Revisions to the control plan shall be submitted to the Executive Director for approval The control plan shall provide a detailed description of the method to be followed to achieve compliance, specifying the anticipated dates by which the following steps will be taken:

(1) dates by which contracts for emission control and monitoring systems will be awarded or dates by which orders will be issued for the purchase of component parts to accomplish emission control or process modification;

(2) date of initiation of on-site construction or installation of emission control equipment or process modification;

(3) date by which on-site construction or installation of emission control equipment or process modification is to be completed, and

(4) date by which final compliance is to be achieved.

§117.413. Continuous Demonstration of Compliance.

(a) The owner or operator of any facility subject to the provisions of this undesignated head (relating to Nitric Acid Manufacturing) shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides (NO_x) from the absorber

(b) Any CEMS installed subject to subsection (a) of this section shall meet all requirements of 40 Code of Federal Regulations (CFR), Part 60, §60 13; 40 CFR 60, Appendix B, Performance Specification 2; and quality assurance procedures of 40 CFR 60, Appendix F, Procedure 1, Section 5.1 2, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5 1.2.

(c) The owner or operator of an affected facility shall establish a conversion factor for the purpose of converting monitoring data into units of the emission standard (in pounds NO_x per ton of acid produced, expressed as 100% nitric acid) as specified in 40 CFR 60, Subpart G, §60.73(b). NO_x emissions data recorded by the CEMS shall be represented in terms of both parts per million by volume and pounds NO_x per ton of acid produced, expressed as 100% nitric acid.

(d) After the initial demonstration of compliance required by §117.411 of this title (relating to Initial Demonstration of Compliance), compliance with §117.405 of this title (relating to Emission Specifications) shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the Executive Director using any Texas Air Control Board compliance method.

§117.419. Notification, Recordkeeping, and Reporting Requirements.

(a) The owner or operator of an affected facility shall submit to the Executive Director written notification, as follows:

(1) verbal notification of the date of any continuous emissions monitoring systems (CEMS) performance evaluation conducted under §117 413(b) of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any performance testing conducted under §117.411 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(b) The owner or operator of an affected facility shall furnish the Executive Director and any local air pollution control agency having jurisdiction a copy of any CEMS performance evaluation conducted under §117.413 of this title (relating to Continuous Demonstration of Compliance), or any performance testing conducted under §117.411 of this title (relating to Initial Demonstration of Compliance), within 60 days after completion of such evaluation or testing. For purposes of demonstrating compliance with §117.530 of this title (relating to Compliance Schedules For Nitric Acid and Adipic Acid Manufacturing Sources), such results shall be submitted no later than 30 days before the final compliance date specified in §117.530 of this title.

(c) The owner or operator of an affected facility shall report in writing to the Executive Director on a quarterly basis all periods of excess emissions, defined as any 24-hour period during which the average nitrogen oxides emissions (arithmetic average of 24 contiguous one-hour periods) as measured by a CEMS exceed the emission limitation in §117.405 of this title (relating to Emission Specifications) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information·

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations, Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period;

(2) specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the affected unit. The nature and cause of any malfunction (if known) and the corrective action taken or preventative measures adopted;

(3) the date and time identifying each period during which the CEMS was inoperative, except for zero and span checks and the nature of the system repairs or adjustments;

(4) when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report;

(5) if the total duration of excess emissions for the reporting period is less than 1 0% of the total operating time for the reporting period and the CEMS downtime for the reporting period is less than 5.0% of the total operating time for the reporting period, only a summary report form (as outlined in the latest edition of the Texas Air Control Board (TACB) "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the Executive Director of TACB If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS downtime for the reporting period is greater than or equal to 5 0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted

(d) The owner or operator of an affected facility shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and daily production rates. Such records shall be kept for a period of at least two years and shall be made available upon request by authorized representatives of TACB, United States Environmental Protection Agency, or any local air pollution control agency having jurisdiction.

§117.421. Alternative Case Specific Specifications. Where a person can demonstrate that an affected unit cannot attain the requirements of §117.405 of this title (relating to Emission Specifications), as applicable, the Executive Director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117 405 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology. Any person affected by the decision of the Executive Director may appeal to the Board by filing written notice of appeal with the Executive Director within 30 days after the decision. Such appeal is to be taken by written notification to the Executive Director. Section 103.71 of this title (relating to Request for Action by the Board) should be consulted for the method of requesting Board action on the appeal. Executive Director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this undesignated head (relating to Nitric Acid Manufacturing).

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority

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Deputy Director, Air Quality Planning
Texas Air Control Board

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For further information, please call (512) 908-1451

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Nitric Acid Manufacturing-General

• 31 TAC §§117.451, 117.455, 117.458

The new rules are adopted under the Texas Health and Safety Code (Vernon 1990), Texas Clean Air Act, §382 017, which provides TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA

§117.451. Applicability The emission limitations specified in §117.455 of this undesignated head (relating to Emission Specifications) shall apply to all nitric acid production units in the state, with the exception that for nitric acid production units located in applicable ozone nonattainment areas, the emission limitations of §117.405 (relating to Emission Specifications) shall apply after May 31, 1995.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority

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Texas Air Control Board

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Subchapter D. Administrative Provisions

• 31 TAC §§117.510, 117.520, 117.530, 117.540, 117.550, 117.560, 117.570

The new rules are adopted under the Texas Health and Safety Code (Vernon 1990), Texas Clean Air Act, §382.017, which provide TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117 510. Compliance Schedule For Utility Electric Generation. All persons affected by the provisions of the undesignated head (relating to Utility Electric Generation) in Subchapter B of this chapter shall be in compliance as soon as practicable, but no later than May 31, 1995 (final compliance date). Additionally, all affected persons shall meet the following compliance schedules and submit written notification to the Executive Director

(1) no later than April 1, 1994, submit a plan for compliance in accordance with §117 109 of this title (relating to Initial Control Plan Procedures),

(2) conduct applicable continuous emissions monitoring system (CEMS) evaluations and quality assurance procedures as specified in §117 113 of this title (relating to Continuous Demonstration of Compliance) no later than January 1, 1995,

(3) install all nitrogen oxides (NO_x) abatement equipment, implement all NO_x control techniques, and submit the results of the CEMS performance evaluation and quality assurance procedures to the Texas Air Control Board no later than May 31, 1995,

(4) conduct applicable tests for initial demonstration of compliance as specified in §117 111 of this title (relating to Initial Demonstration of Compliance) no later than 60 days after May 31, 1995

§117 520. Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources All persons affected by the provisions of the undesignated head (relating to Commercial, Institutional, and Industrial Sources) in Subchapter B of this chapter shall be in compliance as soon as practicable, but no later than May 31, 1995 (final compliance date). All affected persons shall meet the following compliance schedules and submit written notification to the Executive Director

(1) no later than April 1, 1994, submit a plan for compliance in accordance with §117 209 of this title (relating to Initial Control Plan Procedures),

(2) install all nitrogen oxides (NO_x) abatement equipment and implement

all NO_x control techniques no later than May 31, 1995;

(3) for units operating without continuous emissions monitoring system (CEMS), conduct applicable tests for initial demonstration of compliance as specified in §117.211 of this title (relating to Initial Demonstration of Compliance); and submit the results by April 1, 1994, or as early as practicable, but in no case later than May 31, 1995;

(4) for units operating with CEMS and complying with the NO_x emission limit in pound per million Btu on a rolling 30-day average, conduct the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title and submit the results of the applicable CEMS performance evaluation and quality assurance procedures as specified in §117.213 of this title (relating to Continuous Demonstration of Compliance) within 60 days after May 31, 1995.

§117.530. Compliance Schedule For Nitric Acid and Adipic Acid Manufacturing Sources. All persons affected by the provisions of the undesignated head (relating to Adipic Acid Manufacturing) in Subchapter C of this chapter or the provisions of the undesignated head (relating to Nitric Acid Manufacturing) in Subchapter C of this chapter shall be in compliance as soon as practicable, but no later than May 31, 1995 (final compliance date). All affected persons shall meet the following compliance schedules and submit written notification to the Executive Director:

(1) no later than April 1, 1994, submit a control plan for compliance as specified in §117.309 of this title (relating to Control Plan Procedures) and §117.409 of this title (relating to Control Plan Procedures);

(2) conduct applicable continuous emissions monitoring system (CEMS) performance evaluation and quality assurance procedures as specified in §117.313 of this title (relating to Continuous Demonstration of Compliance) and §117.413 of this title (relating to Continuous Demonstration of Compliance); provide previous testing documentation for any claimed test waiver as allowed by §117.311(d) of this title (relating to Initial Demonstration of Compliance) or §117. 411(d) of this title (relating to Initial Demonstration of Compliance); and conduct applicable performance testing as specified in §117.311 of this title and §117.411 of this title, by:

(A) no later than January 1, 1994, for affected facilities not performing process modification or installation of a CEMS device as part of the control plan specified in §117. 309 of this title and §117.409 of this title; and

(B) no later than May 31, 1995, for affected facilities performing process modification or installation of a CEMS device as part of the control plan specified in §117. 309 of this title and §117.409 of this title;

(3) within 60 days after the applicable date specified in paragraph (2)(A) or (B) of this section, submit the results of CEMS performance evaluation and quality assurance procedures and the results of performance testing specified in paragraph (2) of this section.

§117.540. Phased Reasonably Available Control Technology (RACT).

(a) The owner or operator affected by the provisions of this chapter (relating to Control of Air Pollution from Nitrogen Compounds) who believes that compliance by May 31, 1995, is not practicable may submit a petition for phased RACT. The process for submitting a petition and receiving approval shall be based on the following.

(1) The petition shall be submitted with the applicable initial control plan required in §117.109 of this title (relating to Initial Control Plan Procedures), §117.209 of this title (relating to Initial Control Plan Procedures), §117.309 of this title (relating to Control Plan Procedures), or §117.409 of this title (relating to Control Plan Procedures); or as soon as possible after determination by the owner or operator that compliance by May 31, 1995 is not practicable.

(2) The owner or operator of the proposed unit shall submit information to the Texas Air Control Board (TACB) and a copy to the United States Environmental Protection Agency (EPA) Regional Office in Dallas which will demonstrate all of the following.

(A) Compliance by May 31, 1995, is impracticable due to the unavailability of nitrogen oxides abatement equipment, engineering services, or construction labor; system unreliability; or other technological and economic factors (such as costs of additional outages necessitated by compliance with the emission specifications of this title by May 31, 1995, as demonstrated by comparison to costs of actual historical and planned outages) as the TACB determines is appropriate.

(B) There is a proposed stage-by-stage program for compliance and clearly specified compliance milestones for each unit.

(C) There is a commitment to implement the portion of the phased RACT petition that can be implemented by May 31, 1995.

(3) The Executive Director shall approve a petition for phased RACT if the Executive Director determines that compliance is not practicable by May 31, 1995, because of the unavailability of nitrogen oxides abatement equipment, engineering services, or construction labor; system unreliability; or other technological and economic factors (such as costs of additional outages necessitated by compliance with the emission specifications of this title by May 31, 1995, as demonstrated by comparison to costs of actual historical and planned outages) as the TACB determines is appropriate.

(4) Any person affected by the Executive Director's decision may appeal the decision to the Board within 30 days after the date of the decision. Such appeal is to be taken by written notification to the Executive Director. Section 103.71 of this title (relating to Request for Action by the Board) should be consulted for the method of requesting Board action on the appeal. Approved petitions for phased RACT may be revised by the Executive Director upon a showing of just cause by the applicant.

(5) Approval of a phased RACT schedule by the TACB does not waive any applicable federal requirements or eliminate the need for approval by the EPA.

(6) The holder of an approved phased RACT determination shall comply with each specified compliance milestone and each date for compliance provided in the approved petition, as well as any other condition established in the approval.

(b) The Executive Director shall initiate a re-evaluation of the final compliance dates specified in this undesignated head (relating to Administrative Provisions) one year after the adoption of this chapter. The Executive Director shall evaluate the practicability of all sources complying with §117.105 of this title (relating to Emission Specifications), §117.107 of this title (relating to Alternative System-Wide Emission Specifications), §117.205 of this title (relating to Emission Specifications), §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), §117.305 of this title (relating to Emission Specifications), and §117.405 of this title (relating to Emission Specifications), by May 31, 1995. The Executive Director shall base the evaluation on the information contained in the control plans required by §117.109 of this title, §117.209 of this title, §117.309 of this title, and §117.409 of this title. In evaluating the practicability of compliance by May 31, 1995, the Executive Director shall take into consideration the availability of nitrogen oxides abatement equipment, engineering services, construction labor; the system reliability of all affected units; or other technological and economic factors (such as costs of additional outages necessitated by compliance with the emission specifications of this title by May 31, 1995, as demonstrated by comparison to costs of actual historical and planned outages) as the TACB determines is appropriate. Within 15 months after adoption of these rules, the Executive Director shall publish notice in the *Texas Register* the intent to either retain or extend by rulemaking the final compliance dates of this undesignated head.

§117.560. Rescission. If, after reviewing the results of the Urban Airshed Model for a nonattainment area, the Texas Air Control Board (TACB) determines after conducting public hearings that the additional reductions of nitrogen oxides (NO_x) in the nonattainment area would not contribute to attainment of the National Ambient Air Quality Standards for ozone in that nonattainment area, then the TACB shall have the Executive Director submit such findings and results to the United States Environmental Protection Agency (EPA) Administrator for a determination under the 1990 Federal Clean Air Act Amendments, §182(f). If the EPA Administrator approves the TACB's finding, then the requirements of this chapter shall be reproposed in rulemaking to address the findings of the Administrator as to the applicable NO_x requirements.

§117.570. Alternate Means of Compliance-Trading.

(a) The Executive Director may approve alternate means of compliance with this chapter (relating to Control of Air Pollution From Nitrogen Compounds), including the use of emission reduction credits. The alternative compliance plan may include the trading of emission reduction credits between sources owned by the same company as well as between sources owned by different companies. Any alternative compliance plan may be approved if the Executive Director determines that it will provide substantially equivalent emission reductions to those required by this chapter and satisfactory means for determining ongoing compliance with the approved alternative compliance plan, including monitoring. Executive Director approval does not necessarily constitute satisfaction of all federal requirements, nor eliminate the need for approval by the United States Environmental Protection Agency (EPA) of any alternate method.

(b) The Executive Director may consider the establishment of a facility cap as an alternate means of compliance with this chapter. A facility cap plan submitted under this provision may be approved if the Executive Director determines that it will provide substantially equivalent emission reductions to those required by this chapter and establishes satisfactory means for determining ongoing compliance with the facility cap, including appropriate monitoring and recordkeeping requirements. Executive Director approval does not necessarily constitute satisfaction of all federal requirements, nor eliminate the need for approval by the EPA of any alternate method.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 19, 1993.

TRD-9323210 Lane Hartsock
Deputy Director, Air Quality Planning
Texas Air Control Board

Effective date: June 9, 1993

Proposal publication date: November 20, 1992

For further information, please call: (512) 908-1451

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Subchapter E. Gas-Fired Steam Generation

• 31 TAC §117.601

The new rule is adopted under the Texas Health and Safety Code (Vernon 1990), Texas Clean Air Act, §382.017, which provides TACB with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117.601. Gas-Fired Steam Generation.

(a) Subsections (b), (c), and (d) of this section shall apply only in the Dallas/Fort Worth Air Quality Control Region which consists of Collin, Cooke, Dallas, Denton, Ellis, Erath, Fannin, Grayson, Hood, Hunt, Johnson, Kaufman, Navarro, Palo Pinto, Parker, Rockwall, Somervell, Tarrant, and Wise counties and in the Houston/Galveston Air Quality Control Region which consists of Austin, Brazoria, Chambers, Colorado, Fort Bend, Galveston, Harris, Liberty, Matagorda, Montgomery, Waller, and Wharton counties. For gas-fired steam generators located in applicable ozone nonattainment areas, only the emission limitations of §117.105 of this title (relating to Emission Specifications), §117.107 of this title (relating to Alternative System-Wide Emission Specifications), §117.205 of this title (relating to Emission Specifications), and §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) shall apply after May 31, 1995.

(b) No person shall allow emissions of nitrogen oxides (NO_x), calculated as nitrogen dioxide (NO_2), from any "opposed-fired" steam generating unit of more than 600,000 pounds per hour (lbs/hr) maximum continuous steam capacity to exceed 0. 7 pound per million (lb/MM) Btu heat input, maximum two-hour average, at maximum steam capacity. An "opposed-fired" steam generating unit is defined as a unit having burners installed on two opposite vertical firebox surfaces.

(c) No person shall allow emissions of NO_x, calculated as NO_2, from any "front-fired" steam generating unit of more than 600, 000 lbs/hr maximum continuous steam capacity to exceed 0.5 lb/MMBtu heat input, maximum two-hour average, at maximum steam capacity. A "front-fired" steam generating unit is defined as a unit having all burners installed in a geometric array on one vertical firebox surface.

(d) No person shall allow emissions of NO_x, calculated as NO_2, from any "tangential-fired" steam generating unit of more than 600,000 lbs/hr maximum continuous steam capacity to exceed 0.25 lb/MMBtu heat input, maximum two-hour average, at maximum steam capacity. A "tangential-fired" steam generating unit is defined as a unit having burners installed on all corners of the unit at various elevations.

(e) Existing gas-fired steam generating units of more than 600,000 lbs/hour, but less than 1,100,000 lbs/hr, maximum continuous steam capacity are exempt from the provisions of this section, provided the total steam generated from the unit during any one calendar year does not exceed 30% of the product of the maximum continuous steam capacity of the unit times the number of hours in a year. Written records of the amount of steam generated for each day's operation shall be made on a daily basis and maintained for at least three years from the date of each entry. Such records shall be made available for inspection by employees of state and local agencies having jurisdiction during regular business hours.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

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TRD-9323211 Lane Hartsock
Deputy Director, Air Quality Planning
Texas Air Control Board

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