The commission adopts amendments to §117.10, concerning Definitions, §§117.101, 117.103, 117.105, 117.107, 117.109, 117.111, 117.113, 117.115, 117.117, 117.119, and 117.121, concerning Utility Electric Generation; §§117.201, 117.203, 117.205, 117.207-117.209, 117.211, 117.213, 117.215, 117.217, 117.219, 117.221, and 117.223, concerning Commercial, Institutional and Industrial Sources; §§117.510, 117.520, 117.540, concerning Administrative Provisions; and §117.601, concerning Gas-Fired Steam Generation. The changes clarify and improve implementation of certain portions of the commission's rules for existing major stationary sources of nitrogen oxides (NO_x) emissions in ozone nonattainment areas and extend the rules to the Dallas/Fort Worth (DFW) ozone nonattainment area.

Sections 117.10, 117.103, 117.113, 117.119, 117.203, 117.205, 117.207, 117.211, 117.213, 117.215, 117.219, 117.223, 117.510, 117.520, 117.540, and 117.601 are adopted with changes to the proposed text as published in the November 6, 1998, issue of the *Texas Register* (23 TexReg 11281). Sections 117.101, 117.105, 117.107, 117.109, 117.111, 117.115, 117.117, 117.121, 117.201, 117.208, 117.209, 117.217, and 117.221 are adopted without changes and will not be republished.

EXPLANATION OF ADOPTED RULES

One purpose of the revisions to Chapter 117 and to the State Implementation Plan (SIP) is to extend NO_x reasonably available control technology (RACT) requirements to DFW, an area defined by Collin, Dallas, Denton, and Tarrant Counties. The 1990 Federal Clean Air Act (FCAA), §182(f), requires NO_x RACT be applied to all major sources of NO_x in ozone nonattainment areas, unless a demonstration is made that NO_x reductions would not contribute to or would not be necessary for attainment of the ozone standard. By policy, the United States Environmental Protection Agency (EPA) requires photochemical grid modeling to demonstrate whether the §182(f) NO_x measures would contribute to ozone attainment. On November 28, 1994, the EPA granted conditional approval of a §182(f) exemption from NO_x measures for DFW. EPA approval was based on the commission's petition which, based on the modeling at the time, showed that volatile organic compound (VOC) reductions alone would be sufficient for attainment. This meant that NO_x reductions in DFW would be in excess of the reductions necessary for attainment of the ozone standard and were not needed. A condition of EPA's exemption was that it would be rescinded if the area did not attain the ozone standard by November 15, 1996, and modeling later showed that NO_x reductions would contribute to attainment.

The DFW area did not attain the ozone standard in 1996. Effective March 20, 1998, in accordance with the FCAA, §181(b)(2)(B), the EPA reclassified the DFW area from moderate to serious, based on a monitored violation of the ozone standard. The reclassification required the state to submit a new SIP by March 20, 1999, that demonstrates attainment by November 15, 1999.

In 1996, the agency began to develop new modeling for the DFW area and now is using newer air quality models with improved meteorological and emission inputs. The new modeling, which was provided for public hearing and comment concurrently with this rulemaking, shows that NO_x reductions contribute to attainment of the ozone standard in the DFW area. The modeling further indicates that NO_x reductions are a necessary step toward the area's attaining the ozone standard (for both the existing

1-hour and the new 8-hour standard). The failure to attain the standard by 1996 and the results of the new modeling mean the rationale for the NO_x exemption for DFW is no longer valid.
Based upon its conditional approval of the §182(f) exemption (NO_x waiver), EPA will rescind the NO_x waiver and reinstate the requirements for these rules due to the modeling indicating that NO_x reductions will contribute to attainment in the DFW area.

The commission also adopts these revisions in order to improve the implementation of the existing NO_x RACT rules in the Houston/Galveston (HGA) and Beaumont/Port Arthur (BPA) ozone nonattainment areas. These changes are made in response to proposals received from outside entities and from commission staff. Some changes add more explicit recordkeeping and reporting requirements with the objectives of making the requirements more certain and logical, and easier to comply with and to enforce. A benefit is less time spent in determining compliance. Several sections are reorganized significantly to make the rules easier to read and understand. Other clarifications eliminate the need for rule interpretations which are currently posted on the agency's website via the Office of Air Quality's Operating Permits Division.

Numerous minor style changes are adopted. All references in Chapter 117 to "undesignated head" have been changed to "division" to comply with current *Texas Register* requirements for the terminology of rule structure. The term "executive director" replaces references to "Texas Natural Resource Conservation Commission" where the intent is to refer to agency staff. The term "executive director" as defined in the commission's rules, includes any authorized individual designated to act for the executive director. Text changes reduce the number of words without changing meaning or reducing clarity. This type of change includes certain cross-references which are changed to specify the next higher (more general) level of rule structure. Other cross-references are updated to reflect the reorganized requirements.

The amendments to §117.10, concerning Definitions: add DFW to the definitions of applicable ozone nonattainment area, electric power generating system, and major source, and alphabetize the named areas and counties within those definitions; delete the definition of emergency standby gas turbine/engine because this definition is not used in Chapter 117; and modify the definition of unit to clarify that the limitation on replaced capacity applies to emission credits, not the capacity itself. This last revision removes a limitation on replacement units, consistent with a revision to §117.203(b)(1) made through adoption on May 25, 1994 (19 TexReg 4529). At the time, the definition was left unrevised, inadvertently. In addition, the definitions are numbered to comply with current *Texas Register* requirements.

The amendments to §117.101, concerning Applicability: add DFW to the applicable ozone nonattainment areas; alphabetize the named areas; list the affected electric utility units numerically; and insert the defined term “unit” to refer to the affected equipment. Using the term clarifies that the rule applies to equipment placed into service before November 15, 1992 and to functionally identical replacements.

The amendments to §117.103, concerning Exemptions, delete existing subsection (a), which cross-references a now outdated version of the upset and maintenance rules in 30 TAC Chapter 101, concerning the commission's air General Rules. Since the subsection is only a restatement of other rules outside Chapter 117, its deletion reduces the volume of rules and simplifies future rule amendments, without changing the substance of exemptions. In addition, the words "as may be specified" are added in §117.103(b), now relettered (a), to clarify that the cross referenced exceptions are more specific and do not apply to the entire set of exempt categories in §117.103.

The amendment to §117.105(f)-(i), concerning Emission Specifications, combines the gas and oil emission limits into single subsections, reducing repetitive language. The changes to §117.105(n)(2) update the compliance date by referencing §117.510, concerning Compliance Schedule for Utility Electric Generation, and eliminate repetitive language.

The amendments to §117.107, concerning Alternative System-wide Emission Specifications, reorganize the requirements using more of a listing format, to make the text less dense and more readable. The changes to §117.109, concerning Initial Control Plan Procedures, clarify subsection (a) by: specifying the applicable areas; numbering the distinctive requirements; and adding paragraph (1), which states that the section applies only to sources which were major for NO_x emissions before November 15, 1992. The commission does not require initial control plans for DFW sources. The sources are simpler and fewer compared to HGA and BPA, and such plans would provide little information that is not already readily accessible. The amendment to §117.111(c), concerning Initial Demonstration of Compliance, clarifies that the initial relative accuracy test audit (RATA) is part of the initial verification of operational status of the continuous emission monitoring system (CEMS) or predictive emission monitoring system (PEMS). In addition, a cross-reference to the test report requirements in the industrial emission specification is added in §117.111(b) to specify the minimum contents of compliance test reports if the test is based on a 40 Code of Federal Regulations (CFR) 60, Appendix A test apparatus.

Amendments to §117.113, concerning Continuous Demonstration of Compliance, reorganize the requirements for clarity. The changes revise the wording of the current carbon monoxide (CO) monitoring requirements for clarity and move them from subsection (k) to subsection (b). This follows the principle of ordering requirements of more general applicability and importance to the front of the rule. Subsections are given titles (catchlines) to identify the topics covered. Requirements are listed to make the text less dense. The option to share CEMS among units is added to subsection (c), consistent with the corresponding revision adopted in the industrial source division of this chapter. Requirements to install fuel meters are collected in one subsection and clarifying language from the industrial source rule division is added. Existing subsection (j), now relettered to subsection (k), is split into two subsections, parallel to the industrial source rule language.

The amendments to §117.115, concerning Final Control Plan Procedures, add specificity to the requirements. The added specificity is anticipated to significantly reduce the time necessary to assess a source's compliance with NO_x RACT. A change to §117.115(a) clarifies and potentially reduces the number of units needed to be listed in the plan, by substituting a reference to the units specified in §117.101, regarding Applicability, for the less precise term, “affected units.” To facilitate assessment of compliance with NO_x RACT, new §117.115(a)(2) and (6) require citation of the specific rule or exemption used for NO_x compliance. New subsection (a)(3) is designed to reduce the volume of paperwork and simplify tracking, by allowing owners or operators to identify applicable test reports that have previously been submitted, rather than requiring all such reports to be resubmitted at the final compliance date. For many electric utility units, CEMS certifications have already been submitted under the acid rain program and would not need to be resubmitted. The requirement would also aid tracking, by identifying units for which the emission compliance test data will be submitted after the final compliance date, based on 30-day average emission specifications. The changes to §117.115(b) place the requirements in a list format for readability and require identification of the maximum rated capacity and calculations of the system-wide emission limit, to assist in verification of compliance. New §117.115(c) requires certain information to be submitted on forms provided by the executive director (staff). The expected benefit is primarily in reducing the time necessary for staff to assess compliance with NO_x RACT. The requirement to provide copies of the completed forms electronically and on hard copy would allow the staff to distribute the information more efficiently using computer technology while retaining the safeguards of paper. New §117.115(d) places the submittal deadlines at the end of the section and clarifies that the plan is to be updated with 30-day average compliance information that may not be available by the final compliance date.

The adopted amendments to §117.119 add catchlines and number certain requirements for readability. A change to the excess emission reporting requirements of §117.119(d) reduces the frequency of reporting from quarterly to semiannual. This change will result in some savings of effort in the regulated community and will not prevent persons from maintaining a quarterly schedule, if preferred. For consistency, the record retention time specified in recordkeeping, §117.119(e) is changed from two years to five years. The sources subject to Chapter 117 are also subject to FCAA, Title V permit requirements, which specify a 5-year period for retention of compliance records. The recordkeeping wording is simplified. The requirement for recordkeeping of emission monitoring data is cross referenced more generally to the emission monitoring specified in §117.113.

The amendments to §117.121, concerning Alternative Case Specific Specifications, list the requirements for readability. The cross-reference to the commission's procedural rules is updated and the reference to the information that can be found in those rules is deleted.

The amendments to §117.201, concerning Applicability, add DFW to the applicable ozone nonattainment areas and alphabetize the named areas. The changes to §117.203, concerning Exemptions, add the words "as may be specified" to clarify that the cross referenced exceptions are more specific than the entire set of exempt categories in §117.203. In addition, the changes add two types of units which recover sulfur compounds from process streams to the list of exemptions. These additions are consistent with the intent of the Chapter 117 rules developed in 1992, which was to exempt units which commingle fuel and process chemicals. The exemption level for internal combustion engines in DFW is added to §117.203(8)(B), consistent with the level established in the original NO_x RACT rule for a serious ozone nonattainment area.

The amendment to §117.205(a)(3), concerning Emission Specifications, updates the compliance date by referencing §117.520, concerning Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources. Other changes to §117.205(a) and (b) eliminate repetitive language. The change to §117.205(b)(6) clarifies that the hydrogen multiplier may not be used to increase limits set by permit.

The change to §117.205(d)(2) sets the emission specification for rich-burn gas engines in DFW, consistent with the specification previously established in the NO_x RACT rule for a serious ozone nonattainment area. The commission deletes existing §117.205(h), originally drafted to clarify applicability. The insertion of the modifier "NO_x" in the introductory sentences of §117.207, concerning Alternative Plant-wide Emission Specifications, and §117.223(a), concerning Source Cap, clarifies the applicability more efficiently. The reduction in words improves readability.

The amendments to §117.207, concerning Alternative Plant-wide Emission Specifications, reorganize the requirements, using listing and tabular formats, to make the text less dense and more readable. New §117.207(f)(3) clarifies that NO_x opt-in units need to comply with the ammonia and carbon monoxide limits. The purpose of the limits is to require good practice of NO_x control, and the opt-in units should not be exempt from existing standards.

The amendments to §117.209, concerning Initial Control Plan Procedures, clarify subsection (a) by: specifying the applicable areas; numbering the distinctive requirements; and adding paragraph (1), which states that the section applies only to sources which were major for NO_x emissions before November 15, 1992. The commission does not require initial control plans for DFW sources. The sources are simpler and fewer compared to HGA and BPA, and such plans would provide little information that is not already readily accessible.

The amendments to §117.211(a), concerning Initial Demonstration of Compliance, list requirements to reduce the density of the text and clarify that initial testing requirements apply to opt-in sources. The changes to §117.211(c) and (f) clarify that the initial RATA is part of the initial verification of operational status of the CEMS or PEMS. The adopted amendment to §117.211(d) allows some flexibility in the contents of tests conducted before the effective date of the current rule amendments. The addition of §117.211(f)(4) specifies initial compliance procedures for sources complying with the source cap.

New §117.211(g) specifies the minimum contents of compliance stack test and monitor certification reports. The requirements are extracted from Attachment 7, "Contents of Stack Test Reports," from "Air Program Inspector's Manual - Stationary Source and CEMS Test Observation and Test Report Review Protocol," agency publication RG-31d, January 1994. In turn, Attachment 7 is a condensed version of Chapter 14, "Contents of Sampling Reports," from "Sampling Procedures Manual," Texas Air Control Board, July 1985. Chapter 14 is routinely specified in construction permit test requirements. The intent of requiring minimum contents is to ensure that stack sampling resource expenditures, which were estimated at $2000 per test in the original November 20, 1992 NO_x RACT rule proposal (17 TexReg 8144), provide the information necessary to confirm emission compliance. Since these contents have been long established through permit requirements, many existing compliance test reports should be conformable to these adopted standards.

Amendments to §117.213, concerning Continuous Demonstration of Compliance, reorganize the requirements for clarity. The new organization is around elements of the monitoring, rather than sizes of emission units. Titles are added to subsections to identify the topics covered and requirements are listed to make the text less dense. The requirements for fuel meters are consolidated in §117.213(a), from five subsections. In response to frequent requests for clarification, a sentence is added, expressing that "totalizing" may be accomplished by a computer. Units required to install oxygen monitors are listed in §117.213(b). The current CO monitoring requirements are reworded for additional clarity and moved from subsection (l) to subsection (d), consistent with the principle of ordering requirements of more general applicability and importance toward the front of the rule section. The commission revises the allowance to share CEMS, currently in §117.213(b), from a limit of three units to a standard based on performance. The revision to §117.213(e)(3) is in response to a request from a representative of an affected company which has been allowed by permit to share one CEMS among four ethylene furnaces.

In response to a request from a representative of an affected company, new §117.213(e)(1)(C) clarifies that certain ongoing Appendix F quality assurance procedures for CEMS apply after the final compliance date. Similarly, in response to a rule petition, new §117.213(f)(5)(B) and (C) specify the time frame for certain RATA required for PEMS. These changes help to clarify between requirements which must be performed before the final compliance date and those which continue after the final compliance date, as part of ongoing quality assurance. In addition, the changes provide some incentive to install CEMS or PEMS earlier than required, by eliminating the costs associated with performing ongoing quality assurance before the final compliance date. Early monitoring system installation will reduce the potential for a temporary shortage of stack testers, or other service bottlenecks to occur, as a result of the required installation of approximately 300 NO_x monitoring systems by the final compliance date.

The amendments to §117.215, concerning Final Control Plan Procedures, add specificity to the requirements. The added specificity is anticipated to significantly reduce the time necessary to assess a source's compliance with NO_x RACT. A change to §117.215(a) clarifies and potentially reduces the number of units needed to be listed in the plan, by substituting a reference to the units specified in §117.201, regarding Applicability, for the less precise term, "affected units." To facilitate assessment of compliance with NO_x RACT, new §117.215(a)(1), (2), and (6) require citation of the specific rule or exemption used for NO_x compliance for any unit potentially subject to emission specifications under the division. New §117.215(a)(5) is designed to reduce the volume of paperwork and simplify tracking, by allowing owners or operators to identify applicable test reports that have previously been submitted, rather than requiring all such reports to be resubmitted at the final compliance date. The requirement should also aid tracking, by identifying units for which the emission compliance test data will be submitted after the final compliance date, based on 30-day average emission specifications.

The amendments to §117.215(b) place the requirements in a list format for readability and require the owner or operator to provide the maximum rated capacity for each unit and calculations of the plant-wide emission limit, to assist in verification of compliance. Changes to §117.215(c) add paragraphs (1)-(4) to require submittal of calculations and values of key variables necessary to calculate the source cap. New §117.215(d) requires information to be submitted on forms provided by the executive director (staff). The expected benefit is primarily in reducing the time necessary for staff to assess compliance with NO_x RACT. The requirement to provide copies of the completed forms electronically and on hard copy will allow the staff to distribute the information more efficiently using computer technology while retaining the safeguards of paper. Persons required to prepare the plans should benefit from not having to develop forms themselves. The forms will be readily accessible on the agency's website and through conventional means. New §117.215(e) places the submittal deadlines at the end of the section and clarifies that the plan is to be updated with 30-day average compliance information that may not be available by the final compliance date.

The adopted amendments to §117.219 add catchlines and number certain requirements for readability. A change to the excess emission reporting requirements of §117.219(d) and (e) reduces the frequency of reporting from quarterly to semiannual. This change will result in some savings of effort in the regulated community and will not prevent persons from maintaining a quarterly schedule, if preferred. A semiannual reporting frequency is consistent with the reporting frequency specified for federal operating permits in §122.145 of this title, concerning Reporting Terms and Conditions. New §117.219(d)(1)(B) defines periods of excess emissions which must be reported for units operating under a source cap. For consistency, the record retention time specified in recordkeeping, §117.219(f) is changed from two years to five years. The sources subject to Chapter 117 are also subject to federal operating permit requirements, which specify a 5-year period for retention of compliance records.

Additional paragraphs adding specific recordkeeping requirements, §117.219(f)(2)-(8), are adopted in order to consolidate the requirements in one location and to assure that recordkeeping tracks the methods of determining continuous compliance in §117.213 of this title. The purpose of the additions is to assure that units monitored under various compliance options will have the proper data to demonstrate compliance. The types of additional records specified are consistent with the recordkeeping requirements under Chapter 122, relating to Federal Operating Permits. In addition, the added CO recordkeeping addresses a deficiency identified by the EPA in the previous set of revisions to Chapter 117.

The amendments to §117.221, concerning Alternative Case Specific Specifications, use a list format to improve readability. The cross-reference to the commission's procedural rules is updated and the reference to the information that can be found in those rules is deleted.

The amendment to §117.223(a), concerning Source Cap, adds the modifier "NO_x" in the opening sentence, in order to clarify that the source cap is an alternative only to the NO_x emission specifications of §117.105, not the ammonia and CO limits. The purpose of the limits is to require good practice of NO_x control. The change to §117.223(e) revises the reporting frequency to semiannual, consistent with and for the same reasons as discussed previously for reporting required under §117.219 of this title. The changes to §117.223(i) revise the wording to reflect that initial control plans are not required in DFW and substitute the term "initial" for "final" in the last sentence of the subsection. The final control plan demonstrates initial compliance; the terminology follows from previously adopting the term "initial control plan" to refer to a plan which is substantively a preliminary control plan.

The amendments to §117.510, concerning Compliance Schedule for Utility Electric Generation, and §117.520, concerning Compliance Schedule for Commercial, Institutional and Industrial Combustion Sources, subdivide the sections to allow for a separate compliance schedule for sources located in DFW. The commission adopts a compliance date of March 31, 2001 for DFW, as discussed further in the analysis of testimony section of this notice.

Amendments to §117.540, concerning Phased RACT, subdivide the section to create a parallel schedule for sources located in DFW. The existing requirements for HGA and BPA become located under subsection (a), rather than the current “implied (a).” In addition, in §117.540(a)(2) and in §117.540(a)(9), the term “executive director” replaces “commission,” to more accurately reflect the level in the agency at which the action occurs. The change to §117.540(a)(8) deletes an exception which is now repetitive with the commission's procedural rules at 30 TAC §50.37, concerning Motion for Reconsideration. The commission adopts a phased RACT schedule for DFW consistent with the intervals developed for HGA, adjusted according to the DFW final compliance date.

The commission adopts revisions to §117.601(a), concerning Gas-Fired Steam Generation, to clarify the applicability of the section. The changes give historical context to the section and simplify the wording.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code (the Code), §2001.0225, and has determined that the rulemaking is not subject to §2001.0225 because although the new emission limitations may meet the definition of “major environmental rule” as defined in the Code, it does not meet any of the four applicability requirements listed in §2001.0225(a). The amendments implement requirements of the FCAA. The FCAA, §110 requires states to submit SIPs which contain enforceable measures to achieve the National Ambient Air Quality Standards (NAAQS). Section 110(k)(5) requires the EPA to require states to revise a SIP, on a reasonable deadline, if the EPA finds the SIP to be substantially inadequate. The EPA published notice in the February 18, 1998 *Federal Register* of a requirement to submit a new attainment demonstration

SIP for the ozone NAAQS for DFW by March 20, 1999. The adopted rules, which reduce ambient NO_x and ozone in DFW, will be submitted to the EPA, as one of several measures of the required new attainment demonstration.

These rules also implement NO_x RACT in DFW and improve the implementation of NO_x RACT in HGA and BPA. The FCAA, §182(f), requires any moderate and above ozone nonattainment area to implement NO_x RACT, unless the EPA exempts the area under exemption provisions of §182(f). Although DFW currently is covered by such a waiver, EPA will rescind the waiver and reinstate the requirements for these rules, upon submittal of modeling indicating NO_x reductions will contribute to attainment in the DFW area. The modeling is being submitted to EPA concurrently with this adopted rule.

The rules do not exceed an express requirement of a state law, but were developed specifically in order to implement federal law. The rules are part of a new ozone attainment demonstration SIP for DFW, required by the FCAA, §110. The rules also implement the FCAA, §182(f). The rules do not involve an agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program, and were not developed solely under the general powers of the agency.

Other modifications to Chapter 117 do not meet the definition of “major environmental rule” in the Code. These changes, to improve implementation of the rules, affect: applicability, exemption, testing, monitoring, recordkeeping, and reporting requirements. The changes do not require additional control equipment or measures, and the cost to comply with these requirements is not significant.

No comments on the regulatory impact analysis were received.

TAKINGS IMPACT ASSESSMENT

The commission has prepared a Takings Impact Assessment for these sections under Texas Government Code, §2007.043. The following is a summary of that assessment. The specific purposes of these amendments are: to develop a new attainment demonstration SIP for the ozone NAAQS for DFW, to implement NO_x RACT in DFW, and to improve the implementation of NO_x RACT in HGA and BPA. As adopted, certain major sources located in DFW will be subject to new control measures. Installation of such control equipment could conceivably place a burden on private, real property. However, under §2007.003(b)(4) and (b)(13) of the Texas Government Code, Chapter 2007 does not apply to this action. Under §2007.003(b)(4), Chapter 2007 does not apply to an action that is reasonably taken to fulfill an obligation mandated by federal law. The amendments implement requirements of the FCAA, §110 and §182(f). Also, §2007.003(b)(13) states that Chapter 2007 does not apply to an action that: (1) is taken in response to a real and substantial threat to public health and safety; (2) is designed to significantly advance the health and safety purpose; and (3) does not impose a greater burden than is necessary to achieve the health and safety purpose. This action is taken in response to the DFW area exceeding the NAAQS for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient NO_x and ozone levels in DFW. Attainment of the ozone standard will eventually require substantial NO_x reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what the best scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard. In addition, the requirements are expressed as performance specifications, and the rules contain multiple compliance methods to minimize costs of compliance.

Other amendments, to improve the implementation of NO_x RACT, affect: applicability, exemptions, control requirements, testing, reporting, and recordkeeping. These changes do not require additional control equipment or measures, and do not materially affect private real property. The costs of complying with these requirements are not significant.

COASTAL MANAGEMENT PLAN

The commission has determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et. seq.), and the commission's rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the Texas Coastal Management Program. As required by 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3) relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission has reviewed this rulemaking action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and has determined that this rulemaking action is consistent with the applicable CMP goals and policies. The primary CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations at 40 CFR to protect and enhance air quality in the coastal area. The rules, which require additional reductions of air emissions in DFW and improve enforceability of the rules in HGA and BPA, will result in reductions of ambient NO_x and ozone concentrations. The rules are consistent with the applicable CMP policy because they are consistent with 40 CFR, Part 51, which sets out requirements for states to prepare, adopt, and submit implementation plans for the attainment of the NAAQS. The adopted rules will be submitted to EPA under these requirements.

HEARINGS AND COMMENTERS

Public hearings for this rulemaking were held in Irving on December 1, 1998 and in Houston on December 3, 1998. A representative of Texas Utilities (TU) provided oral testimony at the hearing in Irving. Eleven commenters submitted written comments on the proposal: the City of Denton (Denton), the Dallas/Fort Worth International Airport Board (DFWIA), EPA, Exxon Company, U.S.A., Baytown Refinery (Exxon), Garland Power & Light (Garland), an individual, Lockheed Martin Tactical Aircraft Systems (Lockheed), Pavilion Technologies, Inc. (Pavilion), Pennzoil Company (Pennzoil), the Texas Industry Project, via Baker & Botts, L.L.P. (TIP), and TU. Commenters generally supported or did not oppose the proposed revisions, but recommended revisions.

EPA commented that the state must identify all major sources of NO_x over 50 tons per year (tpy) in the DFW area to ensure that RACT is in place for major sources.

The commission has added information regarding application of RACT to major sources of NO_x in DFW in Chapter 6 of the February 1999 DFW Attainment Demonstration SIP adopted with this rulemaking. Appendix K of this SIP identifies the sources of NO_x over 50 tpy in the DFW area.

EPA said exemptions based on heat input and operational parameters must link with the definition of a major source.

The applicability and exemption thresholds in Chapter 117 were developed with consideration to the major source definitions applicable in 1992 in the HGA and BPA areas, 25 tpy and 50 tpy, respectively. The exemptions for low annual capacity factor boilers and heaters were based on the assumption that a 100 million Btu per hour (MMBtu/hr) boiler operating at 25% annual capacity factor could emit 25 tpy of NO_x (18 TexReg 3412, May 28, 1993). The exemption of engines rated less than 300 horsepower (hp) was based on a potential to emit of 50 tpy. The exemption of engines operating less than 850 hours per year was based on cost-effectiveness, which for engines operating less than 10% of annual capacity is at least ten times higher than for continuous operation (18 TexReg 3427).

An individual expressed opposition to deleting the maintenance activity recordkeeping in §117.119(a) and §117.219(a) since, unless reportable quantities of unauthorized emissions are emitted, the company will not have to record its maintenance activities under 30 TAC §101.7. The commenter said these maintenance records allow inspectors to look for problems that while small, could become major in the future. EPA said that Chapter 117 includes reporting requirements for excess emissions during start-up and shutdown that exceed the requirements in Chapter 101. EPA said that the commission needs to ensure that the Chapter 117 requirements meet the guidelines in the EPA policy memo of Kathleen Bennett of February 23, 1983.

The commission, under 30 TAC §101.7, concerning Maintenance, Start-up and Shutdown Reporting, Recordkeeping, and Operational Requirements, requires some recordkeeping for any maintenance activities with unauthorized emissions, not just those associated with reportable quantities of unauthorized emissions. Although the commission proposed to delete requirements to record fuel type and quantity used during start-ups and shutdown events, it has come to the commission's attention that 30 TAC §101.7(c)(6) does not require recording estimates of quantities of unauthorized NO_x emissions above the reportable quantity for boilers and combustion turbines, since there is no reportable quantity for NO_x for these sources. Therefore, after further consideration, the commission has decided to maintain the Chapter 117 recordkeeping requirements in §117.119(a) and §117.219(a). In response to EPA's concerns about following EPA's exemption guidance, the commission notes that Chapter 101 provides any exemptions for start-up or shutdown emissions, not Chapter 117. The commission has adopted the deletion of §117.103(a) and §117.203(a), since these subsections only provided cross reference to Chapter 101 rules, the availability of which is already widely known.

An individual expressed opposition to allowing PEMS, saying that an air monitoring instrument which measures actual pollutant concentration is needed to truly monitor emissions, rather than an estimative device, such as PEMS.

The former Texas Air Control Board authorized PEMS as an alternative to CEMS, because it offered the possibility of equivalent accuracy and lower costs compared to CEMS, and an opportunity to reduce emissions. After more operating experience has been achieved with PEMS, an evaluation of its ability to consistently track NO_x emissions over time will be needed. The commission has made no change in response to the comments.

Exxon expressed support for the proposed revision from quarterly to semiannual excess emission reporting. An individual expressed opposition to reducing the frequency from quarterly to semiannual.

The reduction in reporting frequency is consistent with the federal operating permit reporting requirements contained in §122.145 of this title. The change represents a balance between agency goals to reduce the burdens associated with reporting and ensuring that emissions compliance is assessed periodically. The commission has made no change in response to the comments.

TU and TIP commented that there is an error in the wording of the definition of "system-wide emissions limit" in §117.10(35).

The commission agrees with the commenters. When the definition was previously revised, the wording in question inadvertently was not deleted. The commission has deleted the wording as suggested by the commenters.

TU recommended revision to the fuel oil firing provisions to allow testing of emergency fuel oil systems.

The general rules exempt emissions from maintenance if the owner or operator complies with 30 TAC §101.7 and the emissions are minimized to the extent practicable. Annual testing of emergency fuel oil systems to ensure that the systems are maintained in working order sufficient to maintain system reliability is a form of maintenance. Since the existing rules cover this situation, the commission has made no change in response to this comment.

TU recommended strong consideration be given to NO_x RACT compliance only during the ozone season, May-September.

EPA's definition of RACT is tied to an emission limit based on the application of control technology, which carries an implication of continuous control. Although in one application of NO_x RACT, EPA allowed long-term averaging to allow seasonal fuel switching between coal and gas, EPA insisted upon an annual NO_x limit that would at least meet the limit that would result from compliance with the presumptive NO_x RACT limit. (In that case, the presumptive limit would be the coal limit.) TU's proposal to allow seasonal RACT would not comply with this aspect of EPA's policy.

The issue of seasonal controls also involves air quality considerations. The season for the 1-hour ozone standard in DFW has been defined by EPA policy by the monitoring period in 40 CFR Part

58, Appendix D and by commission rule in §101.29(a)(19) of this title, relating to General Rules, as an 8-month period from March 1 through October 31. For the 8-hour ozone standard, the ozone season tends to be longer in Texas. EPA set an 11-month ozone monitoring season for DFW for the 8-hour standard (EPA-454/R-98-001, June 1998). Although the data provided by TU shows that over the last ten years, the exceedances of the 1-hour standard have been limited to the five months of June-October, there may be ozone and other environmental benefits to year-long NO_x RACT control in DFW. Regional transport may move DFW NO_x southerly into areas with more of a year-long potential for ozone exceedances. Year-long controls could help prevent current near-nonattainment areas from becoming nonattainment under the 8-hour ozone standard. Locally, year-long controls would reduce nitrates in the winter season. Nitrates contribute to the winter visibility impairment in DFW sometimes called the white or brown cloud. In addition, NO_x adds to the nitrification of surface waters, an adverse ecological impact which at times may contribute to algae buildup and related problems.

Weighed against the potential NO_x RACT approvability issue and loss of environmental benefits are the reductions in costs and effort that seasonal NO_x RACT controls would offer. The commission expects that the current emission limits will be complied with through the use of additional combustion controls, for which the expense is primarily capital rather than operating. Capital costs must be incurred regardless of the length of the compliance season. The primary benefit to the utility of an 8-month compliance season would be a reduced compliance effort during a portion of the normal unit outage period, when test firing with fuel oil and other scheduled maintenance may occur. While not minimizing these efforts, particularly the fact that

there has been a documented visibility problem in DFW in the winter has to be weighed carefully against the additional effort. In this regard, year-long compliance makes sense and is consistent with the application of Chapter 117 elsewhere in the state. The commission has made no change in response to this comment.

Garland commented that the CO limitation should not be necessary, since there is a strong cost efficiency incentive to minimize it.

Combustion modifications to reduce NO_x emissions in some cases may result in CO increases. The CO limits of Chapter 117 reflect good combustion practice consistent with implementation of combustion controls for NO_x. Although there is an economic incentive to minimize CO because it represents incomplete use of fuel, this may not be the primary factor until significantly higher levels of CO occur. The commission has made no change in response to this comment.

EPA asked for rule clarification that sources subject to 40 CFR Part 72 are required to use 40 CFR Part 75.22 reference test methods. The EPA also said that the rule should clarify that sources subject to Part 72 must use Part 75, Subpart E, or optional protocol Appendix E of Part 75 for gas- or oil-fired peaking units.

Chapter 117 points to the acid rain NO_x monitoring regulations in Title 40 Part 75 because that program will satisfy the needs of Chapter 117 for those units which are required to monitor NO_x emissions under Part 75. From the context of the requirements for CEMS in §117.113(c) and

§117.213(c)(2), and for PEMS in §117.113(f)(3)-(4), it seems clear that Chapter 117 is not designed to take precedence over the acid rain regulations. The commission disagrees with EPA that Chapter 117 needs to clarify the Title 40 requirements. One of the goals of regulatory reform is to eliminate rule redundancy, and EPA's recommended language is a restatement of federal regulations. The commission has made no change in response to this comment.

Denton recommended that the monitoring for electric utilities in Division 1 of the rule allow sharing of PEMS or CEMS in the same way allowed for industrial sources in Division 2. TIP expressed support for the clarification that a computer may be used to collect, sum, and store electronic data from fuel meters and asked that the same language be included in §117.113 for electric utilities.

The commission agrees with the commenters that these changes would provide more clarity and consistency and has made the necessary changes by inserting the pertinent language from §117.213(e)(3) into §117.113(c) and §117.213(a) into §117.113(h).

EPA commented that they were unclear about recordkeeping and reporting requirements for sources using portable analyzers for periodic sampling of CO allowed in §117.113(b)(2)(A).

The recordkeeping requirement for monitoring data in §117.119(e)(5) was intended to include records of CO monitoring, including periodic CO measurements. The commission has simplified the lead-in sentence to the required recordkeeping in §117.119(e)(5) for clarity.

The reporting requirements of Chapter 117 are geared toward sources which use some type of continuous monitoring system. In Chapter 117, periodic CO monitoring using portable analyzers provides indicator of compliance data, rather than direct compliance data, such as reference method tests, CEMS, PEMS, or steam or water parameter monitoring systems for turbines. The need to provide a specific Chapter 117 procedure for reporting excess CO emissions indicated by portable analyzers would need to be evaluated, and if appropriate, included in a future rulemaking.

DFWIA commented that the language of §117.203, concerning Exemptions, makes it unclear as to the requirements for their stationary engines used for emergency electric power generation.

There are several exemptions which pertain to internal combustion engine (ICE) and more than one may apply. The engines of concern operate less than 850 hours per year and could qualify for the exemption of §117.203(6)(B). Owners or operators using this exemption must use a run time meter and maintain records of monthly operating hours to demonstrate compliance with the exemption criterion, as specified in §117.213(i). An alternative to the exemption in §117.203 could also be used. Two other classes of engines, low annual capacity factor engines, and currently, lean-burn engines, are exempt from Chapter 117 emission limits under §117.205(g)(2) and (6), respectively. Under either of these exemptions, the engine would need a fuel use meter, as specified in §117.213(a)(2). The commission has made no change in response to the comment.

Exxon and TIP commented that the proposed clarification in §117.205(b)(6) and §117.207(h) could be read to restrict the use of the permit limit in cases where the hydrogen multiplier would otherwise increase a level beyond a permit level.

The Chapter 117 NO_x limit is the lower of any Chapter 116 permit limit or the §117.205(b)-(d) limit, as stated in §117.205(a)(1). The adopted revision in §117.205(b)(6) and §117.207(h) reiterates that the hydrogen multiplier cannot be used to increase a permit limit, which would contradict §117.205(a)(1). However, to further clarify the use of the multiplier, the commission has inserted the words "up to" 1.25 in these subsections and in §117.207(g)(4).

Exxon commented that the proposed new §117.207(f)(1) was confusing and added no new meaning. TIP suggested alternative wording for §117.207(f)(1). TIP also suggested that the referant "that" in §117.207(f)(2) should be identified.

Although the language suggested by TIP for §117.207(f)(1) appears to be an improvement, the commission agrees with Exxon that proposed §117.207(f)(1) is repetitive of the preceding sentence in §117.207(f). Proposed §117.207(f)(1) has been deleted and the remaining paragraphs renumbered. In response to TIP's second comment, the commission has also substituted the term "the opt-in" for "that" in proposed §117.207(f)(2), now numbered §117.207(f)(1). For further consistency, "opt" replaces "elect" in §117.207(f) and (f)(2).

DFWIA suggested that the proposed requirement to install boiler oxygen trim systems on their boilers is not a cost-effective method of reducing NO_x.

The requirement to install oxygen or CO trim systems on large industrial, commercial, and institutional boilers was not controversial when developed in concert with extensive negotiations with the regulated community in the HGA and BPA areas. The advantages of such systems are that they can pay for themselves with fuel savings while reducing NO_x due to low excess air operation and reduced firing. However, if possible, it would make more sense to install trim concurrently with attainment demonstration level NO_x controls, especially since, for DFW, any such more stringent rules are likely to be adopted within one year of adoption of the current NO_x RACT rules. A higher level of NO_x control than the current rules also is more likely to necessitate a higher level of boiler operational control, such as oxygen trim. Integrating the operational control requirements in one step would be more cost-effective for the five institutional boilers in DFW which are affected by the oxygen trim requirement. In response to comments on the feasibility of the proposed NO_x RACT implementation schedule, the commission has extended the compliance date to allow two years for NO_x RACT. This additional time should also assist the DFWIA in making a more cost-effective decision in their boiler NO_x control strategy. For consistency with the requirements in HGA and BPA, the commission has retained the requirement to install boiler oxygen or CO trim.

Pennzoil expressed concern that exempted facilities may be cited for not having an initial control plan (ICP) even though they only have exempt sources. They referenced §117.203 which states that specifically listed units are exempt from Chapter 117 except for certain requirements; one of those being the listing requirements in the ICP. Pennzoil suggested that §117.209(c) be revised to limit the submission of ICP to major sources.

Section 117.209(a) limits the ICP to major sources, defined by 25 tpy of NO_x in HGA and 50 in BPA. Therefore, Pennzoil's recommended revision to subsection (c) is not necessary. However, all major sources were required to submit an ICP, not just those which had units subject to the rule's emission specifications. The purpose was to identify the specific reasons for major sources being exempt from the emission limitations. The commission has modified the wording in §117.103(a) and §117.203(a) to clarify that the excepted requirements only apply "as may be specified" in the referenced requirements.

Exxon and TIP recommended changes to §117.211(d) to allow for flexibility in the contents of test reports made before the effective date of the proposed revisions. Otherwise, Exxon said, some sources may be required to redo their compliance tests merely to meet all the paperwork requirements of §117.213(g).

The commenters identified the need to strike a balance between ensuring sufficient data is collected to verify compliance and the likelihood that overly prescriptive requirements could be unnecessarily costly. The lack of certain items listed in §117.211(g), such as brief resume/qualifications of test personnel, should not be sufficient to reject a compliance stack test report made before the effective date of this rule. On the other hand, there is no reason that test

reports made after the effective date of the rule should lack any of the specified information. The commission has revised the language of §117.211(d) and (g) along the lines recommended by the commenters.

Exxon commented that proposed §117.213(a)(2) would require fuel use meters for rich-burn engines subject to emission limits, which is not currently required. Exxon asked that either this requirement be dropped, or the commission justify its inclusion.

The requirement to install a totalizing fuel flow meter on rich-burn engines subject to emission limits is not new, and was previously contained in §117.213(e). Rich-burn engines subject to the Chapter 117 emission limits are large enough to be potential major sources by themselves. Because they represent a significant portion of emissions, it is important to the ozone control strategy that their emissions are quantified. The fuel use meter is a relatively inexpensive way of greatly improving the quantification of emissions from a combustion source. However, §117.213(a)(2) as proposed, inadvertently would expand the fuel meter requirement to engines exempt under the special use and run time exemptions of §117.203. The commission has corrected §117.213(a)(2) so that it more narrowly applies to engines "not exempt by §117.203(6) or (8)."

Exxon recommended §117.213(a)(4) wording be revised from "supplemental fuel fed to FCCU boilers" to "FCCU boilers using supplemental fuel."

The commission appreciates the opportunity to improve the readability of the rule and has made the revision.

TIP supported the option to periodically sample CO but said that the language in §117.213(d)(2) was unclear as to when the testing is required. TIP suggested clarifying that the rule does not require an owner or operator to sample whenever there is any kind of drop in NO_x emissions. TIP suggested adding a time frame for when CO testing is required and a clarification of the rulemaking intent.

The rule language in §117.213(d)(2) defines a specific set of circumstances which require CO sampling. Sampling is required whenever manual tuning or burner adjustments are performed for the purpose of minimizing NO_x and either the NO_x is sampled with an external (portable or reference method) test apparatus, or the manual adjustments are of such an extent that the NO_x operating level is lower than levels for which CO data was previously gathered. Manual adjustments to lower NO_x typically would be an activity scheduled by the owner or operator at his/her convenience. Even unscheduled manual NO_x adjustments only require a CO measurement if clause (i) or (ii) apply. The commission has made several wording changes to improve the readability of the requirements in §117.113(b)(2)(A) and §117.213(d)(2)(A).

TIP questioned why a portable analyzer could not be used for the annual RATA testing required in §117.213(d)(2)(B).

Measurements with test reference method apparatus are considered more reliable than measurements with portable analyzers since, for the former, quality assurance procedures are explicitly laid out in the regulations. The requirement to use a compliance test method here rather than an indicator of compliance method is not burdensome. A sampling van or trailer equipped to measure NO_x using reference test method apparatus is normally equipped to measure CO and any extra efforts to calibrate the CO instrument and record test results are minimal. The commission notes that unless a combustion unit using a NO_x CEMS is subject to an annual NO_x RATA by a requirement outside of Chapter 117, units using NO_x CEMS are allowed to substitute a cylinder gas audit (CGA) for the annual RATA. Therefore, the commission has revised the reference in paragraph (2)(B) from "the" to "any" RATA.

Pavilion recommended that an annual RATA be required for ongoing quality assurance of CEMS, rather than allowing substitution of a CGA for the RATA. EPA expressed concern that the rule allows this substitution.

The specific concerns raised by the commenter regarding problems only found by a RATA deserve further investigation. Historically, the commission, and earlier, the Texas Air Control Board, have allowed CGA to substitute for the annual RATA in state-only new source review permits, because staff believes that the additional costs of the annual RATA were not commensurate with the benefits. The required quarterly CGA are often performed in-house and are easier to schedule than RATA, which generally are performed by outside specialists. For Chapter 117, if 200 CEMS are used, and a RATA costs between $2500-$5000, the annual additional rule cost

would be in the range of $0.5-$1.0 million each year. The staff also believes that a CGA, if performed properly, identifies the ability of the CEMS to accurately measure NO_x and diluent. The CGA requires insertion of the calibration gas at the CEMS probe tip and does not allow pressurization of a negative pressure system. In the example that Pavilion cites it isn't clear whether the proper CGA procedure was followed. Overall, the comments point to the need to assess performance of all types of continuous NO_x monitors used to comply with the rule. The commission has made no change in response to these comments.

Pavilion suggested that the proposal to allow postponing PEMS RATA until six months after November 15, 1999, should be revised to allow the first ongoing RATA to be performed one year after that date, saying the basis should be whether the initial RATA result at normal load is within 7.5%.

It would not be appropriate to use the initial RATA to justify an immediate reduction in the RATA frequency. The initial RATA is likely to be performed shortly after the model is set up. The issue with computer models is whether over time they remain capable of accurately predicting emissions. The existing rule contains an option for a reduction in RATA from the normally expected semiannual frequency to annual frequency, if the model achieves better than acceptable performance in the 6-month period between two consecutive RATA. These two RATA taken together enable some assessment of the ability of the PEMS to predict emissions over time. The commission has made no change in response to this comment.

Pavilion recommended revisions to the performance requirements for PEMS used to predict oxygen (O_2), carbon dioxide (CO_2), and CO. Pavilion said that for the diluents O_2 and CO_2, the relative accuracy (RA) criteria are either no greater than 20% of the mean value of the reference method test data, or 1.0% O_2 or CO_2, whichever is greater. However, the rule currently relies only on the 20% criteria for the RATA skip option. Pavilion recommended if the criterion of 1.0% for O_2 or CO_2, or 5 ppm for CO is used, then only annual RATA should be required.

Pavilion is correct that the federal performance specification test criteria differ for the different compounds. Pavilion's suggested alternative criteria for qualifying for annual RATA is reasonable, since it would avoid the unintended outcomes that diluent rather than NO_x, or CO at levels below regulatory concern, would drive the RATA schedule. The commission has adopted revisions to the requirements of §117.213(f)(5)(C) to address the comment.

Pavilion recommended that the normal emission level test be used to determine if the 7.5% RA criterion is met.

The ongoing RATA is required to be performed at normal load operations. The commission agrees with Pavilion and has revised the requirements in §117.213(f)(5)(C)(iii)(II) accordingly.

EPA asked for an explanation of how the model training process referenced in §117.213(f)(7) ensures PEMS accuracy for alternative fuels.

The intent of the wording is that there may be slight changes to fuel composition for which available data from the model training process could show negligible emission effect, or the data could show that the model adequately predicts emission changes caused by the fuel changes.

Exxon disagreed with the preamble that the additions to §117.215(a), concerning final control report requirements, could reduce the time needed to complete the plan. They said that the additional information would significantly increase the time required to complete the plan and that this should have been included in the analysis of economic impact of the rule. Exxon agreed that the additional information should reduce the time necessary for the agency to assess compliance and said they did not take exception to the data elements that the commission is requesting.

The commission's preamble discussion to the changes in §117.215 assumed that certain changes to the final control plans which may simplify the effort to comply could, in some cases, be greater than the added requirements. Conversely, the commission did not mean to imply that in other cases, the additional requirements would not require additional time to prepare the plans. Chief among the potential time savers is the clarification through the deletion of the term "affected source" in §117.215(a), which is imprecise and has been interpreted in other situations to include exempted equipment. The analysis probably erred in the assumption that requiring the use of standard forms could be a time saver, since providing standard forms but making their use optional would be more likely to save time for the regulated community (although it would reduce the benefit to the commission). The commission may also have overestimated the accessibility of

compliance information at some of the larger sources with numerous separate operating units. The commission has made no change in response to the comments.

Exxon recommended wording changes to §117.215(b) to express that the maximum rated capacity (MRC) doesn't establish a grandfathered rate for a unit. Exxon also recommended minor punctuation and grammatical changes to this subsection.

The MRC is used for Chapter 117 emission averaging only. The MRC does not establish a grandfathered rate for a unit. Inspection of the definition of MRC in Chapter 117 indicates that the methodology for establishing MRC is not based on a particular date, unlike the definition of "grandfathered facility" in Chapter 116. The clarification does not seem essential and the commission has chosen for rule simplicity not to add it. The commission appreciates the opportunity to improve the readability of the rule and has made the minor changes to §117.215(b).

Exxon encouraged the electronic forms specified in §117.215(d) to be provided in draft as soon as possible so that the forms are as user friendly as possible and any conversion bugs between WordPerfect and Microsoft Word can be worked out early.

The commission staff will work with the regulated community to meet their concerns and post the forms on the agency website promptly.

TIP and Exxon suggested the final control plans required in §117.215 should be acceptable for Title V purposes to prevent the same information being required twice on separate agency forms. TIP suggested for Title V, sources could either reference the earlier Chapter 117 submission, or resubmit the identical Chapter 117 forms.

The Title V permit forms are designed to provide a comprehensive list of applicable requirements and the data necessary to identify those requirements for each emission unit at a site. These forms are designed for a database which will track the applicable requirements over time. At the time of application, they will need to reflect the applicable requirements and facility data in effect at that time. In contrast, the Chapter 117 final control plan focuses on such data as emission limit calculations and emission test results, which will be used to substantiate emissions compliance at the Chapter 117 compliance date. This information is needed at the final compliance date to ensure timely improvements in air quality and satisfaction of federal emission reduction requirements. The overlapping information between the Chapter 117 control plans and the Title V forms for Chapter 117 is limited and will become more so, since the submittal dates do not coincide. These major differences make it impractical to substitute or incorporate the Chapter 117 form in the Title V permit form.

Exxon suggested that the reports specified in §117.219(c) be required 60 days after the end of the period.

The rule, in §117.219(c), currently requires the reports to be submitted 30 days after the end of the reporting period. The staff reviewed several air regulations, including 30 TAC §122.145, concerning federal operating permits; 40 CFR §60.7(c), concerning Standards of Performance for New Stationary Sources; and 40 CFR §63.10(d) concerning National Emission Standards for Hazardous Air Pollutants, and found them to consistently specify that reports be submitted within 30 days after the end of the reporting period. The commission has made no change in response to the comment.

EPA pointed out that §117.223(i) calls for owners or operators to identify their intention to use the source cap in the initial control plan, but that for the DFW rules, there is no proposed ICP.

The commission has modified §117.223(i) to correct this drafting error.

TU, Denton, and Garland said that the proposed compliance schedule for the electric utilities was not feasible, realistic, or reasonable. TU recommended extending the RACT implementation deadline for DFW to two years from the adoption of the rule to avoid jeopardy to electric reliability and availability. The commenters cited factors such as adequate time to select vendors, prepare engineering analyses and plans, and order, fabricate, install, and test control equipment. Each commenter referred to the need to schedule installation of controls with regard to downtime or outages. Additionally, Garland mentioned the time needed for a municipal utility to procure any necessary funds through the municipal budget process and Denton cited an insufficient number of control equipment vendors in the area.

TU provided information showing that they were able to achieve about a 20% reduction in NO_x in 1998 from ten of TU's 23 power boilers operating in the area. The information also showed that 12 of the 23 boilers still require significant reductions to achieve compliance with the proposed NO_x RACT rules. Considering the number of TU boilers still required to be retrofit and the other cited factors, the commission believes that a 2-year compliance schedule is reasonable. This schedule is consistent with the original NO_x RACT rule schedule adopted for HGA and BPA. The commission has adopted a compliance date for utility electric generation in DFW of March 31, 2001 in §117.510(b) and correspondingly adjusted the dates in §117.540.

Lockheed expressed concern that they may not accomplish their underway replacement of existing boilers by November 15, 1999 and recommended the rule compliance date be extended to May 15, 2000.

The Chapter 117 NO_x RACT rules are designed to achieve an initial set of point source NO_x emission reductions in DFW expeditiously. Lockheed is in the process of replacing 1941 vintage boilers with new, air quality permitted boilers which will use best available control technology. According to their testimony, they are moving as expeditiously as practicable, and have accelerated the construction schedule to minimize additional cost overruns that have been caused by shortages of construction materials in the DFW area. Since they have contractual obligations to complete the construction, and appear to qualify in other respects, phased RACT would be an option, and any Chapter 117 compliance date would be unlikely to affect the ultimate timing of these reductions. However, maintaining the proposed final compliance date for the industrial

sources would require additional paper work of Lockheed and the commission staff. In consideration of the minimal emission benefits and other factors (relating to boiler trim controls) associated with a November 15, 1999 compliance date, and for consistency with the adopted utility electric generation compliance date, the commission has adopted a compliance date for industrial, institutional, and commercial sources of March 31, 2001 in §117.520(b).

An individual expressed opposition to phased RACT, saying that additional time should not be necessary for rule compliance.

The phased RACT option is expected to be used sparingly. The rule was designed to require clear and substantial criteria to be met to qualify for any additional time. The EPA will also review the phased RACT applications, which will provide additional opportunities for a critical evaluation. The commission has made no changes in response to the comment.

STATUTORY AUTHORITY

The amendments are adopted under the Texas Health and Safety Code, the Texas Clean Air Act (TCAA), §382.012, which requires the commission to develop a general, comprehensive plan for the proper control of the state's air; §382.016, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; and §382.051(d), which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

SUBCHAPTER A : DEFINITIONS

§117.10

§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.

(1) **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.

(2) **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 Hardin, Jefferson, and Orange Counties.

(B) **Dallas/Fort Worth ozone nonattainment area** - An area consisting of Collin, Dallas, Denton, and Tarrant Counties.

(C) **Houston/Galveston ozone nonattainment area** - An area consisting of Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties.

(3) **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.

(4) **Average activity level for fuel oil firing** - The product of an electric utility unit's maximum rated capacity for fuel oil firing and the average annual capacity factor for fuel oil firing for the period from January 1, 1990 to December 31, 1993.

(5) **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.

(6) **Boiler or steam generator** - Any combustion equipment fired with solid, liquid, and/or gaseous fuel used to produce steam.

(7) **Btu** - British thermal unit.

(8) **Chemical processing gas turbine** - A gas turbine that vents its exhaust gases into the operating stream of a chemical process.

(9) **Daily** - A calendar day starting at midnight and continuing until midnight the following day.

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

(11) **Functionally identical replacement** - A unit that performs the same function as the existing unit which it replaces, with the condition that the unit replaced must be physically removed or rendered permanently inoperable before the unit replacing it is placed into service.

(12) **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.

(13) **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.

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

(15) **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.

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

(17) **Lean-burn engine** - A spark-ignited or compression-ignited, Otto cycle, diesel cycle, or two-stroke engine that is not capable of being operated with an exhaust stream oxygen concentration equal to or less than 0.5% by volume, as originally designed by the manufacturer.

(18) **Low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit** - A commercial, institutional, or 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), based on a rolling 12-month average; 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, based on a rolling 12-month average.

(19) **Low annual capacity factor stationary gas turbine or stationary internal combustion engine** - A stationary gas turbine or stationary internal combustion engine which is demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

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

(21) **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 50 tons per year (tpy) of nitrogen oxides (NO_x) and is located in the Beaumont/Port Arthur ozone nonattainment area;

(B) at least 50 tpy of NO_x and is located in the Dallas/Fort Worth ozone nonattainment area; or

(C) at least 25 tpy of NO_x and is located in the Houston/Galveston ozone nonattainment area.

(22) **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.

(23) **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.

(24) **Nitric acid** - Nitric acid which is 30% to 100% in strength.

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

(26) **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.

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

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

(29) **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.

(30) **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.

(31) **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.

(32) **Rich-burn engine** - A spark-ignited, Otto cycle, four-stroke, naturally aspirated or turbocharged engine that is capable of being operated with an exhaust stream oxygen concentration equal to or less than 0.5% by volume, as originally designed by the manufacturer.

(33) **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.

(34) **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.

(35) **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 or portion thereof located within a single ozone nonattainment area when firing at their maximum rated capacity to the total maximum rated capacities for those units. For fuel oil firing, average activity levels shall be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission limit.

(36) **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 or portion thereof located within a single ozone nonattainment area when firing at their maximum rated capacity to the total maximum rated capacities for those units. For fuel oil firing, average activity levels shall be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission rate.

(37) **Unit** - Any boiler, steam generator, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, which is either:

(A) placed into service prior to November 15, 1992; or

(B) placed into service after June 9, 1993 as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter. Any emission credits resulting from the operation of such units shall be limited to the cumulative maximum rated capacity of the units replaced.

(38) **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.

(39) **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.

SUBCHAPTER B : COMBUSTION AT EXISTING MAJOR SOURCES

DIVISION 1 : UTILITY ELECTRIC GENERATION

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

STATUTORY AUTHORITY

The amendments are adopted under the Texas Health and Safety Code, the Texas Clean Air Act (TCAA), §382.012, which requires the commission to develop a general, comprehensive plan for the proper control of the state's air; §382.016, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; and §382.051(d), which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.101. Applicability.

(a) The provisions of this division (relating to Utility Electric Generation) shall apply to the following units 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 Beaumont/Port Arthur, Houston/Galveston, or Dallas/Fort Worth ozone nonattainment areas:

(1) utility boilers;

(2) steam generators;

(3) auxiliary steam boilers; and

(4) gas turbines.

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

§117.103. Exemptions.

(a) Units exempted from the provisions of this division (relating to Utility Electric Generation), except as may be specified in §117.109(b)(1) of this title (relating to Initial Control Plan Procedures) and §117.113(i) of this title (relating to Continuous Demonstration of Compliance), 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 and engines, which are:

(A) used solely to power other engines or gas turbines during start-ups; or

(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(b) The fuel oil firing emission limitation of §117.105(c) or §117.107(b) of this title (relating to Emissions Specifications and Alternative System-wide Emission Specifications) shall not apply during an emergency operating condition declared by the Electric Reliability Council of Texas or the Southwest Power Pool, or any other emergency operating condition which necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the executive director. The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification shall identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and shall be followed by written notification containing this information no later than five days after declaration of the emergency. The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification shall identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

§117.105. Emission Specifications.

(a) - (e) (No change.)

(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 (MW-hr) 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:

(1) 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas; and

(2) 65 ppmv at 15% O_2, dry basis, while firing fuel oil.

(g) 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-hr 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:

(1) 0.20 pound per MMBtu heat input while firing natural gas; and

(2) 0.30 pound per MMBtu heat input while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler subject to the NO_x emission limits specified in subsections (a) - (e) of this section, carbon monoxide (CO) emissions in excess of 400 ppmv, based on a one-hour average for units not equipped with continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) for CO, or on a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO.

(i) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10 MW, CO emissions in excess of a block one-hour average of 132 ppmv at 15% O_2, dry basis.

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

(k) For purposes of this subchapter, the following shall apply:

(1) The lower of any permit NO_x emission limit in effect on June 9, 1993 under a permit issued pursuant to Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and the NO_x emission limits of subsections (a)-(g) of this section shall apply, except that gas-fired boilers operating under a permit issued after March 3, 1982, with an emission limit of 0.12 pound NO_x per MMBtu heat input, shall be limited to that rate for the purposes of this subchapter.

(2) For any unit placed into service after June 9, 1993 and prior to the final compliance date as specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation) or approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (a)-(g) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.107 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

§117.107. Alternative System-wide Emission Specifications.

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine 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).

(1) The following units shall comply with the individual emission specifications of §117.105 of this title and shall not be included in the system-wide emission specification:

(A) gas turbines subject to the emission limits of §117.105(h) or (i) of this title;

(B) auxiliary steam boilers subject to the emission limits of §117.105(a), (c), (d), or (e) of this title.

(2) Coal-fired utility boilers or steam generators shall have a separate system average under this section, limited to those units.

(3) Oil-fired utility boilers or steam generators shall have a separate system average under this section, limited to those units. The emission limit assigned to each oil-fired unit in the system shall not exceed 0.5 pound NO_x per MMBtu based on a rolling 24-hour average.

(b) The owner or operator shall establish enforceable emission limits for each affected unit in the system calculated in accordance with the maximum rated capacity averaging in this section as follows:

(1) for each gas-fired unit in the system, in pound per million (MM) Btu:

(A) on a rolling 24-hour averaging period; and

(B) on a rolling 30-day averaging period;

(2) for each coal-fired unit in the system, in pound per MMBtu on a rolling 24-hour averaging period;

(3) for stationary gas turbines, in the units of the appropriate emission limitation of §117.105 of this title; and

(4) for each fuel oil-fired unit in the system, in pound per MMBtu on a rolling 24-hour averaging period.

(c) An owner or operator of any gaseous and liquid fuel-fired utility boiler, steam generator, or gas turbine shall:

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

(2) comply with the assigned maximum allowable emission rate for liquid fuel while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing, 24-hour average, allowable emission limit and the assigned liquid-firing allowable emission limit while operating on liquid and gaseous fuel concurrently.

(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 average activity level for fuel oil firing or maximum rated capacity for gas firing 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:

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

NO_x (allowable) = the applicable NO_x emission specification of §117.105(f) or (g) of this title (expressed in parts per million by volume NO_x at 15% oxygen (O_2) dry basis)

%H_2O = the volume percent water in the stack gases, as calculated from the manufacturer's data, or other data as approved by the executive director, at MW rating and ISO flow conditions

%O_2 = the volume percent O_2 in the stack gases on a wet basis, as calculated from the manufacturer's data, or other data as approved by the executive director, at the MW rating and ISO flow conditions.

§117.109. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NO_x) located in the Beaumont/Port Arthur or Houston/Galveston ozone nonattainment area shall submit, for the approval of the executive director, an initial control plan for installation of NO_x emissions control equipment and demonstration of anticipated compliance with other applicable requirements of this subchapter.

(1) This section applies only to sources which were major for NO_x emissions before November 15, 1992.

(2) The executive director shall approve the plan if it contains all the information specified in this section.

(3) Revisions to the initial control plan shall be submitted with the final control plan.

(b) (No change.)

§117.111. Initial Demonstration of Compliance.

(a) The owner or operator of all units which are subject to the emission limitations of this division (relating to Utility Electric Generation) must be tested as follows.

(1) Test for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions.

(2) Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions.

(3) Testing shall be performed in accordance with the schedules specified in §117.510(4) and (5) 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 the emission limits of this division. Test results shall be reported in the units of the applicable emission limits and averaging periods. If compliance testing is based on 40 Code of Federal Regulations, Part 60, Appendix A reference methods, the report must contain the information specified in §117.211(g) of this title (relating to Initial Demonstration of Compliance).

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

(d) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.113 of this title shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows:

(1) - (2) (No change.)

(3) To comply with the NO_x emission limit in pounds per hour or parts per million by volume at 15% O_2 dry basis, on a block one-hour average, any one-hour period while operating at the

maximum rated capacity, or as near thereto as practicable, after CEMS or PEMS certification testing required in §117.113 of this title is used to determine compliance with the NO_x emission limit.

(4) (No change.)

§117.113. Continuous Demonstration of Compliance.

(a) NO_x monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Utility Electric Generation), shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure nitrogen oxides (NO_x) on an individual basis.

(b) Carbon monoxide (CO) monitoring. The owner or operator shall monitor CO exhaust emissions from each unit subject to the emission specifications of this division using one or more of the following methods:

(1) install, calibrate, maintain, and operate a:

(A) CEMS in accordance with subsection (c) of this section; or

(B) PEMS in accordance with subsection (f) of this section; or

(2) sample CO as follows:

(A) with a portable analyzer (or 40 CFR 60, Appendix A reference method test apparatus) after manual combustion tuning or manual burner adjustments conducted for the purpose of minimizing NO_x emissions whenever, following such manual changes, either:

(i) NO_x emissions are sampled with a portable analyzer or 40 CFR 60, Appendix A reference method test apparatus; or

(ii) the resulting NO_x emissions measured by CEMS or predicted by PEMS are lower than levels for which CO emissions data was previously gathered; and

(B) sample CO emissions using the test methods and procedures of 40 CFR 60 in conjunction with the annual relative accuracy test audit of the NO_x and diluent analyzer.

(c) CEMS requirements.

(1) Any CEMS required by this section shall be installed, calibrated, maintained, and operated in accordance with 40 CFR, Part 75 or 40 CFR, Part 60, as applicable.

(2) One CEMS may be shared among units, provided:

(A) the exhaust stream of each unit is analyzed separately; and

(B) the CEMS meets the applicable certification requirements of paragraph (1) of this subsection for each exhaust stream.

(d) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR Part 72.2, may:

(1) monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E §1.1 or §1.2 and calculate NO_x emission rates based on those procedures; or

(2) use CEMS or PEMS in accordance with this section to monitor NO_x emission rates.

(e) Auxiliary boilers. The owner or operator of each auxiliary boiler as defined in §117.10 of this title (relating to Definitions) shall:

(1) install, calibrate, maintain, and operate a CEMS in accordance with this section; or

(2) 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).

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section must comply with the following. The required PEMS and fuel flow meters shall be used to demonstrate continuous compliance with the emission limitations of §117.105 or §117.107 of this title (relating to Emission Specifications and Alternative System-wide Emission Specifications).

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission limitations of this division.

(2) Monitor diluent, either oxygen or carbon dioxide:

(A) using a CEMS

(i) in accordance with subsection (b) of this section; or

(ii) with a similar alternative method approved by the executive director and the United States Environmental Protection Agency; or

(B) using a PEMS.

(3) Any PEMS for units subject to the requirements of 40 CFR 75 shall meet the requirements of 40 CFR 75 Subpart E, §§75.40 - 75.48.

(4) Any PEMS for units not subject to the requirements of 40 CFR 75 shall meet the requirements of either:

(A) 40 CFR 75, Subpart E, §§75.40 - 75.48; or

(B) §117.213(f) of this title.

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

(1) for gas turbines rated less than 30 megawatt (MW) 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(g) of this title:

(A) install, calibrate, maintain and operate a CEMS or PEMS in compliance with 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) of this title, install, calibrate, maintain and operate a CEMS or PEMS in compliance with this section.

(h) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate totalizing fuel flow meters to individually and continuously measure the gas and liquid fuel usage. A computer which collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The units are:

(1) any unit subject to the emission specifications of this division;

(2) any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than 850 hours per year (hr/yr); and

(3) any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.103(a)(2) of this title (relating to Exemptions).

(i) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.103(a)(3) of this title shall record the operating time with an elapsed run time meter approved by the executive director.

(j) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemptions of §117.103(a)(2) or (3) of this title, shall notify the executive director within seven days if the applicable limit is exceeded.

(1) If the limit is exceeded, the exemption from the emission specifications of §117.105 of this title shall be permanently withdrawn.

(2) Within 90 days after loss of the exemption, the owner or operator shall 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 limit. The plan shall include a schedule of increments of progress for the installation of the required control equipment.

(3) The schedule shall be subject to the review and approval of the executive director.

(k) Data used for compliance. After the initial demonstration of compliance required by §117.111 of this title (relating to Initial Demonstration of Compliance) the methods required in this section shall be used to determine compliance with the emission specifications of this division. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission compliance method.

(l) Enforcement of NO_x limits. 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) of this title (relating to Final Control Plan Procedures).

§117.115. Final Control Plan Procedures.

(a) The owner or operator of units listed in §117.101 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of this division. The report must include a list of all units listed in §117.101 of this title, showing:

(1) the NO_x emission specification resulting from application of §117.105 of this title (relating to Emission Specifications) for each non-exempt unit;

(2) the section under which NO_x compliance is being established for units specified in paragraph (1) of this subsection, either:

(A) §117.105 of this title;

(B) §117.107 of this title (relating to Alternative Plant-wide Emission Specifications);

(C) §117.121 of this title (relating to Alternative Case Specific Specifications); or

(D) §117.570 (relating to Trading);

(3) the method of control of NO_x emissions for each unit;

(4) the emissions measured by testing required in §117.111 of this title (relating to Initial Demonstration of Compliance);

(5) the submittal date, and whether sent to the Austin or the regional office (or both), of any compliance stack test report or relative accuracy test audit report required by §117.111 of this title which is not being submitted concurrently with the final compliance report; and

(6) the specific rule citation for any unit with a claimed exemption from the emission specifications of this division.

(b) For sources complying with §117.107 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall:

(1) assign to each affected unit the maximum NO_x emission rate, expressed in units of pound per million (MM) Btu heat input on:

(A) a rolling 24-hour average and rolling 30-day average for gaseous fuel firing, and

(B) a rolling 24-hour average for oil or coal firing;

(2) submit a list to the executive director for approval of:

(A) the maximum allowable NO_x emission rates identified in paragraph (1) of this subsection; and

(B) the maximum rated capacity for each unit;

(3) submit calculations used to calculate the system-wide average in accordance with §117.107(e) of this title; and

(4) maintain a copy of the approved list of emission limits for verification of continued compliance with the requirements of §117.107 of this title.

(c) The lists of information required in this section must be submitted electronically and on hard copy using forms provided by the executive director. This requirement does not apply to calculations or other explanatory information.

(d) The report must be submitted by the applicable date specified for final control plans in §117.510 of this title (relating to Compliance Schedule For Utility Electric Generation). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with an emission limit on a rolling 30-day average, according to the applicable schedule given in §117.510 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 division (relating to Utility Electric Generation). For sources complying with §117.105 of this title (relating to Emission Specifications), or §117.107 of this title (relating to Alternative System-Wide Emission Specifications), replacement new units may be included in the control plan. The revision of the final control plan shall be subject to the review and approval of the executive director.

§117.119. Notification, Record keeping, and Reporting Requirements.

(a) Start-up and shutdown records. For units subject to the start-up and/or shutdown exemptions allowed under §101.11 of this title (relating to Exemptions from Rules and Regulations), 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 executive director, the Unites 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 event.

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Utility Electric Generation) shall submit notification to the executive director as follows:

(1) verbal notification of the date of any initial demonstration of compliance 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 systems (CEMS) or predictive emissions monitoring systems (PEMS) 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) Reporting of test results. 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 initial demonstration of compliance testing conducted under §117.111 of this title or any CEMS or PEMS performance evaluation conducted under §117.113 of this title:

(1) within 60 days after completion of such testing or evaluation; and

(2) not later than the appropriate compliance schedules specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, 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 semiannual basis any exceedance of the applicable emission limitations in this division and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations (CFR), 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 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 demonstration of compliance 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, PEMS, 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 commission's "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the executive director. 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) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records shall be kept for a period of at least five years and made available for inspection by the executive director, 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 for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records 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) emission monitoring data, pursuant to §117.113 of this title, including:

(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 initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or operating parameter monitoring systems; and

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

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.111 of this title; and

(7) records of hours of operation.

§117.121. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.105 of this title (relating to Emission Specifications), the executive director may approve emission specifications different from §117.105 of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine 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; and

(3) in determining whether to approve alternative emission specifications, 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.

(b) Any person affected by the executive director's decision to deny an alternative case specific emission specification may file a motion for reconsideration. The requirements of §50.39 of this title (relating to Motion for Reconsideration) apply. However, only a person affected may file a motion for reconsideration. 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 division (relating to Utility Electric Generation).

SUBCHAPTER B : COMBUSTION AT EXISTING MAJOR SOURCES

DIVISION 2 : COMMERCIAL, INSTITUTIONAL, AND INDUSTRIAL SOURCES

§117.201, 117.203, 117.205, 117.207, 117.208, 117.209, 117.211, 117.213, 117.215, 117.217, 117.219, 117.221, 117.223

STATUTORY AUTHORITY

The amendments are adopted under the Texas Health and Safety Code, the Texas Clean Air Act (TCAA), §382.012, which requires the commission to develop a general, comprehensive plan for the proper control of the state's air; §382.016, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; and §382.051(d), which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.201. Applicability.

The provisions of this division (relating to Commercial, Institutional, and Industrial Sources) shall apply to the following units located at any major stationary source of nitrogen oxides located within the Beaumont/Port Arthur, Dallas/Fort Worth, or Houston/Galveston ozone nonattainment areas:

(1) - (2) (No change.)

(3) stationary internal combustion engines which are:

(A) (No change.)

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

§117.203. Exemptions.

Units exempted from the provisions of this division (relating to Commercial, Institutional, and Industrial Sources), except as may be specified in §117.209(c)(1) of this title (relating to Initial Control Plan Procedures) and §117.213(a) and (i) of this title (relating to Continuous Demonstration of Compliance), include the following:

(1) any new units placed into service after November 15, 1992, except for new units which were placed into service as functionally identical replacement for existing units subject to the provisions of this division as of June 9, 1993. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced;

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

(3) any electric utility power generating boiler;

(4) flares, incinerators, fume abaters, pulping liquor recovery furnaces, sulfur recovery units, sulfuric acid regeneration 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; or

(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(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 or Dallas/Fort Worth ozone nonattainment area with a hp 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), or §117.223 of this title (relating to Source Cap).

(1) - (2) (No change.)

(3) For any unit placed into service after June 9, 1993 and before the final compliance date as specified in §117.520 of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources or the final compliance date as approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (b)-(d) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be

limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.207 or §117.223 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(b) For boilers and process heaters which operate with continuous emission monitors (CEMS) or predictive emissions monitors (PEMS) in accordance with §117.213 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 MMBtu), 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 boilers and process heaters which do not operate with CEMS or PEMS, 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 boiler's or process heater's maximum rated capacity and its applicable limit in pound NO_x per MMBtu. For each boiler and process heater with a maximum rated capacity greater than or equal to 100.0 MMBtu/hr of heat input, the applicable emission limit is as follows:

(1) - (5) (No change.)

(6) for 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, a multiplier of up to 1.25 times the appropriate emission limit in this

subsection may be used 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. The multiplier may not be used to increase limits set by permit.

(c) (No change.)

(d) 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) (No change.)

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

(e) No person shall allow the discharge into the atmosphere from any boiler or process heater subject to NO_x emission specifications in subsection (a) or (b) of this section, CO emissions in excess of the following limitations:

(1) - (2) (No change.)

(3) for units equipped with CEMS or PEMS for CO, the limits of paragraphs (1) and (2) of this subsection shall apply on a rolling 24-hour averaging period. For units not equipped with CEMS or PEMS for CO, the limits shall apply on a one-hour average.

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

(g) (No change.)

§117.207. Alternative Plant-wide Emission Specifications.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.205 of this title (relating to Emission Specifications) by achieving equivalent 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).

(b) The owner or operator shall establish an enforceable (NO_x) emission limit for each affected unit at the source as follows.

(1) For boilers and process heaters which operate with continuous emission monitors (CEMS) or predictive emission monitors (PEMS) in accordance with §117.213 of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply as:

(A) 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

(B) as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average.

(2) For boilers and process heaters which do not operate with CEMS or PEMS, 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.

(3) For stationary gas turbines, the emission limits shall apply as the NO_x concentration in parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis on a block one-hour average.

(4) For stationary internal combustion engines, the emission limits shall apply in units of grams NO_x per horsepower-hour (g NO_x/hp-hr) on a block one-hour average.

(c) - (e) (No change.)

(f) Units exempted from emission specifications in accordance with §117.205(g) of this title are also exempt under this section and shall not be included in the plant-wide emission limit, except as follows. The owner or operator of exempted units as defined in §117.205(g) of this title may opt to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications.

(1) Low annual capacity factor boilers, process heaters, gas turbines, or engines as defined in §117.10 of this title are not to be considered as part of the opt-in class of equipment.

(2) The ammonia and carbon monoxide emission specifications of §117.205 of this title apply to the opt-in units.

(3) The individual NO_x emission limit that is to be used in calculating the alternative plant-wide emission specifications is the lower of any applicable permit emission specification determined in accordance with §117.205(a) of this title and the specification of paragraph (4) of this subsection.

(4) The equipment classes which may be included in the alternative plant-wide emission specifications and the NO_x emission rates that are to be used in calculating the alternative plant-wide emission specifications are listed in the following table, §117.207(f) OPT-IN UNITS:

§117.207(f) OPT-IN UNITS

Equipment Class/Description	Emission Specification
fluid catalytic cracking unit carbon monoxide (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 ppmv converted into lb NO_x/MMBtu of heat input
lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 hp or greater	5.0 g NO_x/hp-hr under all operating conditions
boilers, steam generators, or process heaters with a maximum rated capacity (MRC): 40 MMBtu/hr $\leq$ MRC $<$ 100 MMBtu/hr	the emission specifications in §117.205(a) of this title for the applicable type of unit
stationary gas turbines with a MW rating: 1.0 MW $\leq$ MW rating $<$ 10.0 MW	42 ppmv NO_x at 15% O_2, dry basis
boilers and industrial furnaces 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	the appropriate emission limitation in §117.205(b) of this title

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

(1) For each affected boiler and process heater, the rate is the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title.

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

Where:

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

NO_x (allowable) = the applicable NO_x emission specification of §117.205(c) 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 from the manufacturer's data, or other data as approved by the executive director, 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 from the manufacturer's data, or other data as approved by the executive director, at MW rating and ISO flow conditions.

(4) 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, may be adjusted with a multiplier of up to 1.25 times the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title.

(A) Double application of the H_2 content multiplier using this paragraph and §117.205(b)(6) of this title is not allowed.

(B) The multiplier may not be used to increase a limit set by permit.

(C) The fuel gas composition must be sampled and analyzed every three hours.

(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 up to 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 or to increase limits set by permit. 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) 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) - (d) (No change.)

§117.209. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NO_x) located in the Beaumont/Port Arthur or Houston/Galveston ozone nonattainment area shall submit, for the approval of the executive director, an initial control plan for installation of NO_x emissions control equipment (if required in order to comply with the emission specifications of this subchapter) and demonstration of anticipated compliance with the applicable requirements of this subchapter.

(1) This section applies only to sources which were major for NO_x emissions before November 15, 1992.

(2) The executive director shall approve the plan if it contains all the information specified in this section.

(3) Revisions to the initial control plan shall be submitted with the final control plan.

(b) The owner or operator shall provide results of emissions testing using portable or reference method analyzers or, as available, initial demonstration of compliance testing conducted in accordance with §117.211(e) or (f) of this title (relating to Initial Demonstration of Compliance) for NO_x, carbon monoxide (CO), and oxygen 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 and/or solid fuel at the maximum rated capacity or as near thereto as practicable, for the units listed in this subsection. Previous testing documentation for any claimed test waiver as allowed by §117.211(d) of this title shall be submitted with the initial control plan. Any units which were not operated between June 9, 1993 and April 1, 1994 and do not have earlier representative emission test results available shall be tested and the results submitted to the executive director, with certification of the equipment's shutdown period, within 90 days after the date such equipment is returned to operation. Test results are required for the following units:

(1) - (6) (No change.)

(c) 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) - (7) (No change.)

(8) 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 this division. For fluid catalytic cracking unit 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) - (C) (No change.)

(9) for units required to install totalizing fuel flow meters in accordance with §117.213(a) of this title (relating to Continuous Demonstration of Compliance), indication of whether the devices are currently in operation, and if so, whether they have been installed as a result of the requirements of this chapter;

(10) - (11) (No change.)

§117.211. Initial Demonstration of Compliance.

(a) The owner or operator of all units which are subject to the emission limitations of this division (relating to Commercial, Institutional, and Industrial Sources) must test the units as follows.

(1) Test for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions while firing gaseous fuel or, as applicable:

(A) hydrogen (H_2) fuel for units which may fire more than 50% H_2 by volume; and

(B) liquid and solid fuel.

(2) Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions.

(3) Test all units belonging to equipment classes which are elected to be included in

(A) the alternative plant-wide emission specifications as defined in §117.207(f) of this title (relating to Alternative Plant-Wide Emission Specifications); or

(B) the source cap as defined in §117.223(b)(4) of this title (relating to Source Cap).

(4) Initial demonstration of compliance testing shall be performed in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources).

(b) The initial demonstration of compliance tests required by subsection (a) of this section shall use the test methods referenced in subsection (e) or (f) of this section and shall be used for determination of initial compliance with the emission limits of this division. Test results shall be reported in the units of the applicable emission limits and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) or any predictive emissions monitoring system (PEMS) required by §117.213 of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational before conducting testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the initial relative accuracy test audit and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(d) Early testing conducted before the effective date of this rule as revised may be used to demonstrate compliance with the standards specified in this division, if the owner or operator of an affected facility demonstrates to the executive director that the prior compliance testing at least meets the requirements of subsections (a), (b), (c), (e), and (f) of this section. For early testing, the compliance stack test report required by subsection (g) shall be as complete as necessary to demonstrate to the executive director that the stack test was valid and the source has complied with the rule. The executive director reserves the right to request compliance testing or CEMS or PEMS performance evaluation at any time.

(e) Compliance with the emission specifications of this division for units operating without CEMS or PEMS shall be demonstrated while operating at the maximum rated capacity, or as near thereto as practicable. Compliance shall be determined by the average of three one-hour emission test runs, using the following test methods:

(1) - (6) (No change.)

(f) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.213 of this title, shall be demonstrated after monitor certification testing using the CEMS or PEMS as follows.

(1) (No change.)

(2) For units complying with a NO_x emission limit on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable is used to determine compliance with the NO_x emission limit.

(3) For units complying with a CO emission limit, on a rolling 24-hour average, any 24-hour period is used to determine compliance with the CO emission limit.

(4) For units complying with §117.223 of this title (relating to Source Cap), a rolling 30-day average of total daily pounds of NO_x emissions from the units are monitored (or calculated in accordance with §117.223(c) of this title) for 30 successive source 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 daily emissions data recorded by the monitoring and recording system during the 30-day test period. There must be no exceedances of the maximum daily cap during the 30-day test period.

(g) Compliance stack test reports must include the following minimum contents.

(1) Introductory information. Provide background information pertinent to the test, including:

(A) company name, address, and name of company official responsible for submitting report;

(B) name and address of testing organization;

(C) names of persons present, dates and location of test;

(D) schematic drawings of the unit being tested, showing emission points, sampling sites, and stack cross section with the sampling points labeled and dimensions indicated;

(E) description of the process being sampled; and

(F) facility identification number (FIN) used to identify the unit in the final control plan.

(2) Summary information. Provide summary information, including:

(A) a summary of emission rates found, reported in the units of the applicable emission limits and averaging periods, and compared with the applicable emission limit;

(B) the maximum rated capacity, normal maximum capacity, and actual operating level of the unit during the test (in MMBtu/hr, hp, or MW, as applicable), and description of the method used to determine such operating level;

(C) the operating parameters of any active NO_x control equipment during the test, (for example, percent flue gas recirculation, ammonia flow rate, etc); and

(D) documentation that no changes to the unit have occurred since the compliance test was conducted that could result in a significant change in NO_x emissions.

(3) Procedure. Describe the procedures used and operation of the sampling train and process during the test, including:

(A) a schematic drawing of the sampling devices used with each component designated and explained in a legend;

(B) a brief description of the method used to operate the sampling train and procedure used to recover samples; and

(C) deviation from reference methods, if any.

(4) Analytical technique. Provide a brief description of all analytical techniques used to determine the emissions from the source.

(5) Data and calculations. Include all data and calculations, of:

(A) field data collected on raw data sheets;

(B) log of process operating levels, including fuel data;

(C) laboratory data, including blanks, tare weights, and results of analysis; and

(D) emission calculations.

(6) Chain of custody. Include a listing of the chain of custody of the emission or fuel test samples, as applicable.

(7) Appendix. Provide:

(A) calibration work sheets for sampling equipment;

(B) collection of process logs of process parameters;

(C) brief resume/qualifications of test personnel; and

(D) description of applicable continuous monitoring system, as applicable.

(8) Monitor certification reports. Monitor certification reports must contain:

(A) information which demonstrates compliance with the certification requirements of §117.213(d) or (f) of this title for CEMS or PEMS, as applicable; and

(B) the relative accuracy test audit formation specified in 40 CFR 60, Appendix B, Performance Specification 2, Section 9.

§117.213. Continuous Demonstration of Compliance.

(a) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate a totalizing fuel flow meter to individually and continuously measure the gas and liquid fuel usage. A computer which collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The units are:

(1) the following units, if individually rated more than 40 million Btu per hour (MMBtu/hr):

(A) boilers;

(B) process heaters;

(C) boilers and industrial furnaces regulated as existing facilities by the EPA at 40 Code of Federal Regulations (CFR) Part 266, Subpart H; and

(D) gas turbine supplemental-fired waste heat recovery units;

(2) stationary, reciprocating internal combustion engines not exempt by §117.203(6) or (8) of this title (relating to Exemptions);

(3) stationary gas turbines with a MW rating greater than or equal to 1.0 MW operated more than 850 hours per year; and

(4) fluid catalytic cracking unit boilers using supplemental fuel.

(b) Oxygen monitors. The owner or operator shall install, calibrate, maintain, and operate an oxygen (O_2) monitor to measure exhaust O_2 concentration on the following units operated with an annual heat input greater than $2.2(10^{11})$ Btu per year (Btu/yr):

(1) boilers with a rated heat input greater than or equal to 100 MMBtu/hr; and

(2) process heaters with a rated heat input:

(A) greater than or equal to 100 MMBtu/hr and less than 200 MMBtu/hr; and

(B) greater than or equal to 200 MMBtu/hr, except as provided in subsection (f) of this section.

(c) Nitrogen oxides (NO_x) monitors.

(1) The owner or operator of units listed in this paragraph shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) to monitor exhaust NO_x. The units are:

(A) boilers 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) process heaters 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) stationary gas turbines with a megawatt (MW) rating greater than or equal to 30 MW operated more than 850 hours per year;

(D) units which use a chemical reagent for reduction of NO_x; and

(E) units for which the owner or operator elects to comply with the NO_x emission specifications of this division using a pound per MMBtu limit on a 30-day rolling average.

(2) The following are not required to install CEMS or PEMS under this subsection:

(A) units listed in §117.205(g)(3)-(5) of this title (relating to Emission Specifications); and

(B) gas turbines or other units which are affected units and are subject to continuous emissions monitoring requirements in accordance with 40 CFR 75.

(d) Carbon monoxide (CO) monitoring. The owner or operator shall monitor CO exhaust emissions from each unit listed in subsection (c)(1) of this section using one or more of the following methods:

(1) install, calibrate, maintain, and operate a:

(A) CEMS in accordance with subsection (e) of this section; or

(B) PEMS in accordance with subsection (f) of this section; or

(2) sample CO as follows:

(A) with a portable analyzer (or 40 CFR 60, Appendix A reference method test apparatus) after manual combustion tuning or manual burner adjustments conducted for the purpose of minimizing NO_x emissions whenever, following such manual changes, either of the following occur:

(i) NO_x emissions are sampled with a portable analyzer or 40 CFR 60, Appendix A reference method test apparatus; or

(ii) the resulting NO_x emissions measured by CEMS or predicted by PEMS are lower than levels for which CO emissions data was previously gathered; and

(B) sample CO emissions using the test methods and procedures of 40 CFR 60 in conjunction with any relative accuracy test audit of the NO_x and diluent analyzer.

(e) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section must comply with the following.

(1) The CEMS shall meet the requirements of 40 CFR, Part 60 as follows:

(A) Section 60.13;

(B) Appendix B:

(i) Performance Specification 2, for NO_x;

(ii) Performance Specification 3, for diluent; and

(iii) Performance Specification 4, for CO, for owners or operators electing to use a CO CEMS; and

(C) After the final compliance date, audits in accordance with Section 5.1 of Appendix F, quality assurance procedures, except that a cylinder gas audit or relative accuracy audit may be performed in lieu of the annual relative accuracy test audit (RATA) required in Section 5.1.1.

(2) Monitor diluent, either O_2 or CO_2.

(3) One CEMS may be shared among units, provided:

(A) the exhaust stream of each unit is analyzed separately; and

(B) the CEMS meets the certification requirements of paragraph (1) of this subsection for each exhaust stream.

(4) The CEMS shall be subject to the approval of the executive director.

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section must comply with the following.

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission limitations of this division.

(2) Monitor diluent, either O_2 or CO_2:

(A) using a CEMS

(i) in accordance with subsection (e)(1)(B)(ii) of this section; or

(ii) with a similar alternative method approved by the executive director and the United States Environmental Protection Agency (EPA); or

(B) using a PEMS.

(3) Any PEMS shall meet the requirements of 40 CFR 75, Subpart E, except as provided in paragraphs (4)-(5) of this subsection.

(4) The owner or operator may vary from 40 CFR 75, Subpart E if the owner or operator:

(A) demonstrates to the satisfaction of the executive director and EPA that the alternative is substantially equivalent to the requirements of 40 CFR 75, Subpart E; or

(B) demonstrates to the satisfaction of the executive director that the requirement is not applicable.

(5) The owner or operator may substitute the following as an alternative to the test procedure of Subpart E for any unit:

(A) perform the following alternative initial certification tests:

(i) conduct initial RATA at low, medium, and high levels of the key operating parameter affecting NO_x using 40 CFR Part 60, Appendix B:

(I) Performance Specification 2, subsection 4.3 (pertaining to NO_x);

(II) Performance Specification 3, subsection 2.3 (pertaining to O_2 or CO_2); and

(III) Performance Specification 4, subsection 2.3 (pertaining to CO), for owners or operators electing to use a CO PEMS; and

(ii) conduct an F-test, a t-test, and a correlation analysis using 40 CFR 75, Subpart E at low, medium, and high levels of the key operating parameter affecting NO_x.

(I) Calculations shall be based on a minimum of 30 successive emission data points at each tested level which are either 15-minute, 20-minute, or hourly averages.

(II) The F-test shall be performed separately at each tested level.

(III) The t-test and the correlation analysis shall be performed using all data collected at the three tested levels;

(B) further demonstrate PEMS accuracy and precision for at least one unit of a category of equipment by performing RATA and statistical testing in accordance with subparagraph (A) of this paragraph for each of three successive quarters, beginning:

(i) no sooner than the quarter immediately following initial certification; and

(ii) no later than the first quarter following the final compliance date; and

(C) after the final compliance date, perform RATA for each unit:

(i) at normal load operations;

(ii) using the appropriate procedures of paragraph (5)(A)(i)(I)-(III) of this subsection; and

(iii) at the following frequency:

(I) semiannually; or

(II) annually, if following the first semiannual RATA, the relative accuracy during the previous audit for each compound monitored by PEMS is less than or equal to 7.5 % of the mean value of the reference method test data at normal load operation; or alternatively,

-a- for diluent, is no greater than 1.0 % O_2 or CO_2, for diluent measured by reference method at less than 5% by volume; or

-b- for CO, is no greater than 5 parts per million by volume.

(6) The owner or operator shall, for each alternative fuel fired in a unit, certify the PEMS in accordance with paragraph (5)(A) of this subsection unless the alternative fuel effects on NO_x, CO, and O_2 (or CO_2) emissions were addressed in the model training process.

(7) The PEMS shall be subject to the approval of the executive director.

(g) Engine monitoring. The owner or operator of any stationary gas engine subject to the emission specifications of this division shall stack test engine NO_x and CO emissions as follows.

(1) Use the methods specified in §117.211(e) of this title (relating to Initial Demonstration of Compliance).

(2) Sample:

(A) on a biennial calendar basis; or

(B) within 15,000 hours of engine operation after the previous emission test, under the following conditions:

(i) install and operate an elapsed operating time meter; and

(ii) submit, in writing, to the executive director and any local air pollution agency having jurisdiction, biennially after the initial demonstration of compliance:

(I) documentation of the actual recorded hours of engine operation since the previous emission test; and

(II) an estimate of the date of the next required sampling.

(h) Monitoring for gas turbines less than 30 MW. 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 or §117.207 of this title (relating to Alternative Plant-wide Emission Specifications) shall either:

(1) install, calibrate, maintain, and operate a NO_x CEMS or PEMS in compliance with this section and monitor CO in compliance with subsection (d) 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.

(A) The system shall be accurate to within $\pm$ 5.0%.

(B) 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 or §117.207 of this title.

(C) Steam or water injection control algorithms are subject to executive director approval.

(i) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the 850 hours per year exemption of §117.203(b)(6)(B) of this title (relating to Exemptions) shall record the operating time with an elapsed run time meter.

(j) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.205(b)(6), §117.207(g)(4), or (h) of this title shall sample, analyze, and record every three hours the fuel gas composition to determine the volume percent H_2.

(1) 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.

(2) Fuel gas analysis shall be tested according to American Society of Testing and Materials (ASTM) Method D1945-81 or ASTM Method D2650-83, or other methods which are demonstrated to the satisfaction of the executive director and the EPA to be equivalent.

(3) 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.

(A) A fuel gas analysis shall 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.

(B) The process flow diagram of the process unit which is the source of the H_2 shall be supplied to the executive director to illustrate the source and supply of the hydrogen stream.

(C) 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.

(k) Data used for compliance. After the initial demonstration of compliance required by §117.211 of this title, the methods required in this section shall be used to determine compliance with the emission specifications of this division. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

(l) Enforcement of NO_x limits. 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) of this title (relating to Final Control Plan Procedures).

(m) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.205(g)(2) of this title, shall notify the executive director within seven days if the Btu/yr or hour-per-year limit specified in §117.10 of this title, as appropriate, is exceeded.

(1) If the limit is exceeded, the exemption from the emission specifications of §117.205 of this title shall be permanently withdrawn.

(2) Within 90 days after loss of the exemption, the owner or operator shall 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 limit. The plan shall include a schedule of increments of progress for the installation of the required control equipment.

(3) The schedule shall be subject to the review and approval of the executive director.

§117.215. Final Control Plan Procedures.

(a) The owner or operator of units listed in §117.201 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of this division (relating to Commercial, Institutional, and Industrial Sources). The report must include a list of the units listed in §117.201 of this title, showing:

(1) the NO_x emission specification resulting from application of §117.205 of this title (relating to Emission Specifications) for each non-exempt unit;

(2) the section under which NO_x compliance is being established for units specified in paragraph (1) of this subsection, either:

(A) §117.205 of this title;

(B) §117.207 of this title (relating to Alternative Plant-wide Emission Specifications);

(C) §117.221 of this title (relating to Alternative Case Specific Specifications);

(D) §117.223 (relating to Source Cap); or

(E) §117.570 (relating to Trading);

(3) the method of control of NO_x emissions for each unit;

(4) the emissions measured by testing required in §117.211 of this title (relating to Initial Demonstration of Compliance);

(5) the submittal date, and whether sent to the Austin or the regional office (or both), of any compliance stack test report or relative accuracy test audit report required by §117.211 of this title which is not being submitted concurrently with the final compliance report; and

(6) the specific rule citation for any unit with a claimed exemption from the emission specifications of this division, for:

(A) boilers and heaters with a maximum rated capacity greater than or equal to 100.0 million Btu per hour;

(B) gas turbines with a megawatt (MW) rating greater than or equal to 10 MW; and

(C) gas-fired internal combustion engines rated greater than or equal to:

(i) 150 horsepower (hp) in the Houston/Galveston ozone nonattainment area; and

(ii) 300 hp in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area.

(b) For sources complying with §117.207 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall:

(1) assign to each affected:

(A) boiler or process heater, the maximum allowable NO_x emission rate in pound per million (MM) Btu (rolling 30-day average), or in pounds per hour (block one-hour average) indicating whether the fuel is gas, high-hydrogen gas, solid, or liquid;

(B) stationary gas turbine, the maximum allowable NO_x emission in parts per million by volume at 15% oxygen, dry basis on a block one-hour average; and

(C) stationary internal combustion engine, the maximum allowable NO_x emission rate in grams per horsepower-hour on a block one-hour average;

(2) submit a list to the executive director for approval of:

(A) the maximum allowable NO_x emission rates identified in paragraph (1) of this subsection; and

(B) the maximum rated capacity for each unit;

(3) submit calculations used to calculate the plant-wide average in accordance with §117.207(g) of this title; and

(4) maintain a copy of the approved list of emission limits for verification of continued compliance with the requirements of §117.207 of this title.

(c) For sources complying with §117.223 of this title (relating to Source Cap), in addition to the requirements of subsection (a) of this section, the owner or operator shall submit:

(1) the calculations used to calculate the 30-day average and maximum daily source cap allowable emission rates; and

(2) a list containing, for each unit in the cap:

(A) the historical average daily heat input information H_i;

(B) the maximum daily heat input, H_{mi};

(C) the applicable restriction, R_i;

(D) the method of monitoring emissions; and

(3) an explanation of the basis of the values of H_i, H_{mi}, and R_i; and

(4) the information applicable to shutdown units, specified in §117.223(g) and (h) of this title.

(d) The lists of information required in this section must be submitted electronically and on hard copy using forms provided by the executive director. This requirement does not apply to calculations or other explanatory information.

(e) The report must be submitted by the applicable date specified for final control plans in §117.520 of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Sources). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with an emission limit on a rolling 30-day average, according to the applicable schedule given in §117.520 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 division (relating to Commercial, Institutional, and Industrial Sources). For sources complying with §117.205 of this title (relating to Emission Specifications), or §117.207 of this title (relating to Alternative Plant-wide Emission Specifications), replacement new units may be included in the control plan. For sources complying with §117.223 of this title (relating to Source Cap), any new unit shall be included in the source cap, if the unit belongs to an equipment category which is included in the source cap. 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) Start-up and shutdown records. For units subject to the start-up and/or shutdown exemptions allowed under §101.11 of this title (relating to Exemptions from Rules and Regulations), 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 executive director, 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) Notification. The owner or operator of an affected source shall submit notification to the executive director, as follows:

(1) verbal notification of the date of any initial demonstration of compliance 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) or predictive emissions monitoring system (PEMS) 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) Reporting of test results. 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 initial demonstration of compliance testing conducted under §117.211 of this title and any CEMS or PEMS relative accuracy test audit (RATA) conducted under §117.213 of this title:

(1) within 60 days after completion of such testing or evaluation; and

(2) not later than the compliance schedule specified in §117.520 of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, 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 semiannual basis any exceedance of the applicable emission limitations of this division (relating to Commercial, Institutional, and Industrial Sources) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. 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.

(A) For gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.213(h)(2) of this title, excess emissions are computed as each one-hour period during which the average steam or water injection rate is below the level defined by the control algorithm as necessary to achieve compliance with the applicable emission limitations in §117.205 of this title.

(B) For units complying with §117.223 of this title (relating to Source Cap), excess emissions are each daily period for which the total NO_x emissions exceed the rolling 30-day average or the maximum daily NO_x cap.

(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, PEMS, 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 commission's "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the executive director. 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, PEMS, 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) Reporting for engines. The owner or operator of any rich-burn engine subject to the emission limitations in §117.205 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 semiannual period. Written reports shall include the following information:

(1) the magnitude of excess emissions (based on the quarterly emission checks of §117.208(d)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.213(g) 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) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain written or electronic records of the data specified in this subsection. Such records shall be kept for a period of at least five years and shall be made available upon request by authorized representatives of the executive director, EPA, or local air pollution control agencies having jurisdiction. The records shall include:

(1) For each unit using a CEMS or PEMS in accordance with §117.213 of this title, monitoring records of:

(A) hourly emissions and fuel usage for units complying with an emission limit enforced on a block one-hour average; and

(B) daily emissions and fuel usage for units complying with an emission limit enforced on a rolling 30-day average. Emissions recorded in units of:

(i) pound per million Btu heat input; and

(ii) pounds or tons per day.

(2) for each internal combustion engine subject to the emission specifications of this division, records of:

(A) emissions measurements required by:

(i) §117.208(7) of this title (relating to Operating Requirements); and

(ii) §117.213(g) of this title; and

(B) catalytic converter or air-fuel ratio controller maintenance, including the date and nature of corrective actions taken.

(3) for each gas turbine monitored by steam-to-fuel or water-to-fuel ratio in accordance with §117.213(h) of this title, records of hourly:

(A) pounds of steam or water injected;

(B) pounds of fuel consumed; and

(C) the steam-to-fuel or water-to-fuel ratio.

(4) for hydrogen (H_2) fuel monitoring in accordance with §117.213(j) of this title, records of the volume percent H_2 every three hours.

(5) for units claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.205(g)(2), either records of monthly:

(A) fuel usage, for exemptions based on heat input; or

(B) hours of operation, for exemptions based on hours per year of operation.

(6) Records of carbon monoxide measurements specified in §117.213(d)(2) of this title.

(7) records of the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring systems.

(8) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.211 of this title.

§117.221. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.205 of this title (relating to Emission Specifications), the executive director may approve emission specifications different from §117.205 of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine 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; and

(3) in determining whether to approve alternative emission specifications, 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.

(b) Any person affected by the executive director's decision to deny an alternative case specific emission specification may file a motion for reconsideration. The requirements of §50.39 of this title (relating to Motion for Reconsideration) apply. However, only a person affected may file a motion for reconsideration. 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 division (relating to Commercial, Institutional, and Industrial Sources).

§117.223. Source Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.205 of this title (relating to Emission Specifications) by achieving equivalent NO_x emission reductions obtained by compliance with a source cap emission limitation in accordance with the requirements of this section. Each equipment category at a source whose individual emission units would otherwise be subject to the NO_x emission limits of §117.205 of this title may be included in the source cap. Any equipment category included in the source cap shall include all emission units belonging to that category. Equipment categories include, but are not limited to, the following: steam generation, electrical generation, and units with the same product outputs, such as ethylene cracking furnaces. All emission units not included in the source cap shall comply with the requirements of §117.205 or §117.207 (relating to Alternative Plant-wide Emission Specifications) of this title.

(b) The source cap allowable mass emission rate shall be calculated as follows.

(1) A rolling 30-day average emission cap shall be calculated for all emission units included in the source cap using the following equation:

$$\begin{array}{c}NO_x \text{ 30-day rolling} \\ \text{average emission cap} \\ \text{(lb/day)}\end{array} = \sum_{i=1}^{N} (H_i \times R_i)$$

Where:

I = each emission unit in the emission cap

N = the total number of emission units in the emission cap

H_i = The actual historical average of the daily heat input for each unit included in the source cap, in million (MM) Btu per day, as certified to the executive director, for a 24 consecutive month period between January 1, 1990 and June 9, 1993, plus one standard deviation of the average daily heat input for that period. All sources included in the source cap shall use the same 24 consecutive month period. If sufficient historical data are not available for this calculation, the executive director may approve another method for calculating H_i.

R_i = (A) For emission units subject to the federal New Source Review (NSR) requirements of 40 Code of Federal Regulations (CFR) 51.165(a), 40 CFR 51.166, or 40 CFR 52.21, or to the requirements of Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) which implements these federal requirements, or emission units that have been subject to a New Source Performance Standard requirement of 40 CFR 60 prior to June 9, 1993, R_i is the lowest of the actual emission rate or all applicable federally enforceable emission limitations as of June 9, 1993, in pounds (lb) NO_x per MMBtu, that apply to emission unit *I* in the absence of trading. All calculations of emission rates shall presume that emission controls in effect on June 9, 1993 are in effect for the two-year period used in calculating the actual heat input.

(B) For all other emission units, R_i is the lowest of the reasonably available control technology (RACT) limit of §117.205(b)-(d) or §117.207(f) of this title or the best available control technology limit for any unit subject to a permit issued pursuant to Chapter 116 of this title, in lb NO_x/MMBtu, that applies to emission unit *I* in the absence of trading.

(2) A maximum daily cap shall be calculated for all emission units included in the source cap using the following equation:

$$\text{NO}_x \text{ maximum daily cap (lb/day)} = \sum_{i=1}^{N} \left(H_{Mi} \times R_i\right)$$

Where:

I, N, and R_i are defined as in paragraph (1) of this subsection.

H_{mi} = The maximum daily heat input, as certified to the executive director, allowed or possible (whichever is lower) in a 24-hour period.

(3) - (6) (No change.)

(c) The owner or operator who elects to comply with this section shall:

(1) for each unit included in the source cap, either:

(A) install, calibrate, maintain, and operate a continuous exhaust NO_x monitor, carbon monoxide (CO) monitor, an oxygen (O_2) (or carbon dioxide (CO_2)) diluent monitor, and a totalizing fuel flow meter in accordance with the requirements of §117.213 of this title (relating to

Continuous Demonstration of Compliance). The required continuous emissions monitoring systems (CEMS) and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel use for each affected unit and shall be used to demonstrate continuous compliance with the source cap;

(B) install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS) and a totalizing fuel flow meter in accordance with the requirements of §117.213 of this title. The required PEMS and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit and shall be used to demonstrate continuous compliance with the source cap; or

(C) for units not subject to continuous monitoring requirements and units belonging to the equipment classes listed in §117.207(f) of this title, the owner or operator may use the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.211(e) of this title (relating to Initial Demonstration of Compliance) in lieu of CEMS or PEMS. Emission rates for these units shall be limited to the maximum emission rates obtained from testing conducted under §117.211(e) of this title.

(2) For each operating unit equipped with CEMS, the owner or operator shall either use a PEMS pursuant to §117.213 of this title, or the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.211(e) of this title, to provide emissions compliance data during periods when the CEMS is off-line. The methods specified in 40 CFR 75.46 shall be used to provide emissions substitution data for units equipped with PEMS.

(d) (No change.)

(e) The owner or operator of any units operating under this provision shall report any exceedance of the source cap emission limit within 48 hours to the appropriate regional office. The owner or operator shall then follow up within 21 days of the exceedance with a written report which includes an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance. Additionally, the owner or operator shall submit semiannual reports for the monitoring systems in accordance with §117.219 of this title.

(f) (No change.)

(g) A unit which has operated since November 15, 1990, and has since been permanently retired or decommissioned and rendered inoperable prior to June 9, 1993, may be included in the source cap emission limit under the following conditions.

(1) - (2) (No change.)

(3) The actual heat input shall be calculated according to subsection (b)(1) of this section. If the unit was not in service 24 consecutive months between January 1, 1990, and June 9, 1993, the actual heat input shall be the average daily heat input for the continuous time period that the unit was in service, plus one standard deviation of the average daily heat input for that period. The

maximum heat input shall be the maximum heat input, as certified to the executive director, allowed or possible (whichever is lower) in a 24-hour period;

(4) - (5) (No change.)

(h) (No change.)

(i) An owner or operator who chooses to use the source cap option shall include in the initial control plan, if required to be filed under §117.209 of this title (relating to Initial Control Plan Procedures), a plan for initial compliance. The owner or operator shall include in the initial control plan the identification of the election to use the source cap procedure as specified in this section to achieve compliance with this section and shall specifically identify all sources that will be included in the source cap. The owner or operator shall also include in the initial control plan the method of calculating the actual heat input for each unit included in the source cap, as specified in subsection (b)(1) of this section. An owner or operator who chooses to use the source cap option shall include in the final control plan procedures of §117.215 of this title (relating to Final Control Plan Procedures) the information necessary under this section to demonstrate initial compliance with the source cap.

(j) (No change.)

SUBCHAPTER D : ADMINISTRATIVE PROVISIONS

§§117.510, 117.520, 117.540

STATUTORY AUTHORITY

The amendments are adopted under the Texas Health and Safety Code, the Texas Clean Air Act (TCAA), §382.012, which requires the commission to develop a general, comprehensive plan for the proper control of the state's air; §382.016, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; and §382.051(d), which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.510. Compliance Schedule For Utility Electric Generation.

(a) The owner or operator of each electric utility in the Beaumont/Port Arthur or Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter (relating to Utility Electric Generation) as soon as practicable, but no later than November 15, 1999 (final compliance date). The owner or operator shall:

(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) or predictive emissions monitoring systems (PEMS) evaluations and quality assurance procedures as specified in §117.113 of this title (relating to Continuous Demonstration of Compliance) according to the following schedules:

(A) for equipment and software required pursuant to 40 Code of Federal Regulations (CFR) 75, no later than January 1, 1995 for units firing coal, and no later than July 1, 1995 for units firing natural gas or oil; and

(B) for equipment and software not required under 40 CFR 75, no later than November 15, 1999;

(3) install all nitrogen oxides (NO_x) abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(4) submit to the executive director:

(A) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(B) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

(i) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title; and

(ii) the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(iii) no later than:

(I) November 15, 1999, for units complying with the NO_x emission limit on an hourly average; and

(II) January 15, 2000, for units complying with the NO_x emission limit on a rolling 30-day average;

(5) conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117.111(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(6) submit a final control plan for compliance in accordance with §117.115 of this title (relating to Final Control Plan Procedures), no later than November 15, 1999.

(b) The owner or operator of each electric utility in the Dallas/Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than March 31, 2001 (final compliance date). The owner or operator shall:

(1) conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title no later than March 31, 2001;

(2) install all NO_x abatement equipment and implement all NO_x control techniques no later than March 31, 2001;

(3) submit to the executive director:

(A) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title no later than March 31, 2001;

(B) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

(i) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title; and

(ii) the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(iii) no later than:

(I) March 31, 2001 for units complying with the NO_x emission limit in pounds per hour on a block one-hour average.

(II) May 31, 2001 for units complying with the NO_x emission limit on a rolling 30-day average; and

(4) conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117.111(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(5) submit a final control plan for compliance in accordance with §117.115 of this title, no later than March 31, 2001.

§117.520. Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources.

(a) The owner or operator of each commercial, institutional, and industrial source in the Beaumont/Port Arthur or Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 2 of this chapter, (relating to Commercial, Institutional, and Industrial Sources) as soon as practicable, but no later than November 15, 1999 (final compliance date). The owner or operator shall:

(1) submit a plan for compliance in accordance with §117.209 of this title (relating to Initial Control Plan Procedures) according to the following schedule:

(A) for major sources of nitrogen oxides (NO_x) which have units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than April 1, 1994;

(B) for major sources of NO_x which have no units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than September 1, 1994; and

(C) for major sources of NO_x subject to either subparagraphs (A) or (B) of this paragraph, submit the information required by §117.209(c)(6), (7), and (9) of this title no later than September 1, 1994;

(2) install all NO_x abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(3) submit to the executive director:

(A) for units operating without continuous emissions monitoring system (CEMS) or predictive emissions monitoring systems (PEMS), the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(B) for units operating with CEMS or PEMS in accordance with §117.213 of this title (relating to Continuous Demonstration of Compliance), submit the results of:

(i) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A)-(B) and (f)(3)-(5)(A) of this title; and

(ii) the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title;

(iii) no later than:

(I) November 15, 1999, for units complying with the NO_x emission limit on an hourly average; and

(II) January 15, 2000, for units complying with the NO_x emission limit on a rolling 30-day average;

(C) a final control plan for compliance in accordance with §117.215 of this title (relating to Final Control Plan Procedures), no later than November 15, 1999; and

(D) the first semiannual report required by §117.217(c) or (d) of this title (relating to Revision of Final Control Plan), covering the period November 15, 1999 through December 31, 1999, no later than January 31, 2000.

(b) The owner or operator of each commercial, institutional, and industrial source in the Dallas/Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter B, Division 2 of this chapter as soon as practicable, but no later than March 31, 2001 (final compliance date). The owner or operator shall:

(1) install all NO_x abatement equipment and implement all NO_x control techniques no later than March 31, 2001; and

(2) submit to the executive director:

(A) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title as early as practicable, but in no case later than March 31, 2001;

(B) for units operating with CEMS or PEMS in accordance with §117.213 of this title, the results of:

(i) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A)-(B) and (f)(3)-(5)(A) of this title; and

(ii) the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title;

(iii) no later than:

(I) March 31, 2001, for units complying with the NO_x emission limit on an hourly average; and

(II) May 31, 2001, for units complying with the NO_x emission limit on a rolling 30-day average;

(C) a final control plan for compliance in accordance with §117.215 of this title, no later than March 31, 2001; and

(D) the first semiannual report required by §117.217(c) or (d) of this title, covering the period March 31, 2001 through June 30, 2001, no later than July 31, 2001.

§117.540. Phased Reasonably Available Control Technology (RACT).

(a) The owner or operator of a source located in the Beaumont/Port Arthur or Houston/Galveston ozone nonattainment area affected by the provisions of this chapter (relating to Control of Air Pollution from Nitrogen Compounds) who determines that compliance by November 15, 1999, is not practicable may submit a petition for phased reasonably available control technology (RACT). The process for submitting a petition and receiving approval shall be based on the following.

(1) The petition shall be submitted by March 15, 1999, or as soon as possible after such date upon a demonstration by the owner or operator that the petition was not submitted by March 15, 1999 due to unforeseen circumstances.

(2) The owner or operator of the affected unit or units shall submit information in the petition to the executive director and a copy to the EPA regional office in Dallas which will demonstrate all of the following:

(A) emission reduction credits (ERCs) or discrete emission reduction credits (DERCs), in accordance with §101.29 of this title (relating to Emission Credit Banking and Trading), are not reasonably available in an amount equal to the quantity of emission reductions required under this chapter. If ERCs or DERCs are reasonably available, they shall be applied to meet the emission reductions required under this chapter, in accordance with §117.570 of this title (relating to Trading) and §101.29 of this title.

(B) compliance by November 15, 1999, is impracticable due to the unavailability of nitrogen oxides (NO_x) abatement equipment, engineering services, or construction labor; system unreliability; manufacturing unreliability; equipment unreliability; or other technological and economic factors as the executive director determines are appropriate;

(C) there is a proposed stage-by-stage program for compliance and clearly specified compliance milestones for each unit;

(D) there is a commitment to implement the portion of the phased RACT petition that can be implemented by November 15, 1999; and

(E) the final compliance date specified in the petition shall be as soon as practicable, but in no case later than February 15, 2001, except as approved by the executive director.

(3) Each petition for phased RACT shall contain the information required by at least one of the following criteria.

(A) If compliance by November 15, 1999, is impracticable due to the unavailability of NO_x abatement equipment, engineering services, or construction labor, the following information shall be included in the petition for phased RACT:

(i) a list of the company names, addresses, and telephone numbers of vendors who are qualified to provide the services and equipment capable of meeting the applicable emission limitation under this chapter and who have been contacted to obtain the required services and equipment. A copy of the request for bids along with the dates of contact shall also be provided to show a good-faith effort to obtain the required services and equipment necessary to meet the requirements of this chapter by November 15, 1999; and

(ii) copies of responses from each of the vendors listed in clause (i) of this subparagraph showing that they cannot provide the necessary services and install the appropriate equipment in time for the unit to comply by November 15, 1999. Such responses shall include the reasons why the services cannot be provided and why the equipment cannot be installed in a timely manner.

(iii) if work on the project will be provided by the owner or operator, the petition for phased RACT shall include documentation that the necessary NO_x abatement equipment, engineering services, or construction labor could not be obtained in a timely manner from either in-house or external sources, as well as a detailed design or installation schedule for the required services or equipment to be provided by the owner or operator.

(B) If compliance by November 15, 1999, is impracticable due to system unreliability for sources in the utility industry, defined as the inability or threatened inability of a utility grid system to fulfill obligations to supply electric power, the following information shall be included in the petition for phased RACT:

(i) standard load forecasts, based on standard forecasting models available throughout the utility industry, applied to the period November 15, 1997 - November 14, 1999;

(ii) outage schedule for all units in the utility grid to which the subject unit belongs; and

(iii) specific reasons why an outage for the purpose of installing NO_x emission control equipment cannot be scheduled by November 15, 1999.

(C) If compliance by November 15, 1999, is impracticable due to manufacturing unreliability, defined as the inability or threatened inability of a source to fulfill contractual obligations to supply a product or products, the following information shall be included in the petition for phased RACT:

(i) certification by an authorized official of the company showing manufacturing obligations for which the company is contractually obligated. Manufacturing obligation information shall include copies of contracts signed by an authorized official of the company or similar documentation and shall exclude commercially sensitive information;

(ii) historical and planned outage schedules for all units whose manufacturing capacity would be affected by the outage of the affected unit; and

(iii) specific reasons why an outage for the purpose of installing NO_x emission control equipment cannot be scheduled by November 15, 1999.

(D) If compliance by November 15, 1999, is impracticable due to equipment unreliability, defined as the reduced availability and operating reliability of a unit resulting from the operation of NO_x control equipment on that unit, the following information shall be included in the petition for phased RACT:

(i) specific reasons why the new NO_x control equipment will reduce the current reliability of the operating unit;

(ii) historical availability and forced outage data expressed as annual percentages and the differences in each expected with the new NO_x control equipment. Availability is defined as the sum of hours the equipment is in service plus the hours the equipment is not in service, but available for service, divided by the number of hours in the reporting period. A forced outage is defined as down time which occurs as a result of a trip, emergency shutdown, or unplanned maintenance;

(iii) most recent operating history available from the vendor for the new NO_x control equipment, including actual test operating hours, actual load during testing, and specific problems that resulted in lost availability; and

(iv) reasons why the NO_x control technology is not considered proven including vendor test and commercial operating data, if available from the vendor.

(E) If compliance by November 15, 1999, is impracticable due to other technical factors, the petition for phased RACT shall contain such documentation as the executive director establishes is appropriate for such technical factors.

(F) If compliance by November 15, 1999, is unreasonable due to economic considerations, excluding the time value of money, the petition for phased RACT shall contain the following information showing comparisons of the cost of compliance by November 15, 1999 and the cost of compliance by the final compliance date specified in the petition:

(i) the costs of additional outages, if applicable, necessitated by compliance with the emission specifications of this chapter by November 15, 1999, as demonstrated by comparison to costs of actual historical and planned outages;

(ii) comparisons of the cost of obtaining the NO_x abatement equipment, engineering services, or construction labor necessary to comply by November 15, 1999, and the cost of obtaining the NO_x abatement equipment, engineering services, or construction labor by the final compliance date specified in the petition. Copies of legally binding contracts, signed by an authorized official of the company, shall be submitted to document these costs. If the required NO_x abatement equipment, engineering services, or construction labor will be provided by the owner or operator, as provided for in paragraph (4) of this subsection, certification by an authorized official of the company may be submitted in lieu of contracts to document these costs; or

(iii) other economic factors, documented as the executive director establishes is appropriate for such economic factors.

(4) All petitions for phased RACT shall include a list of the company names, addresses, and telephone numbers of persons who own or control ERCs or DERCs, and who have been contacted in efforts to obtain the ERCs or DERCs for purposes of meeting the emission reductions required under this chapter. For each person or company contacted, the list shall contain a description of the information obtained, including but not limited to the date of contact, availability of the ERCs or DERCs, sale price requested by the owner or controller of the ERCs or DERCs, sale price offered by

the prospective buyer of the ERCs or DERCs, and an explanation of the reasons why the ERCs or DERCs, if available, were not purchased for purposes of meeting the emission reductions required under this chapter.

(5) All petitions for phased RACT shall include copies of legally binding contracts with the primary vendors for each project, signed by an authorized official of the company, showing a detailed design or installation schedule for the required services or equipment to be provided by that vendor, with a completion date no later than February 15, 2001, except as approved by the executive director. Any commercially sensitive financial information or trade secrets should be excised from the contracts.

(6) Within 30 days of receiving a petition for phased RACT, the executive director shall inform the applicant in writing that the petition is complete or that additional information is required. If the petition is deficient, the notification shall state any additional information required. The requested information correcting the deficiency shall be received by the executive director within 30 days of the date of the letter notifying the applicant of the deficiency.

(7) The executive director shall approve or deny the petition within 90 days of receiving an administratively complete phased RACT petition. The executive director shall approve a petition for phased RACT if the executive director determines that compliance is not practicable by November 15, 1999, because of either the unavailability of nitrogen oxides abatement equipment, engineering services, or construction labor; system unreliability; manufacturing unreliability; equipment

unreliability; or other technological and economic factors as the executive director determines are appropriate.

(8) Any person affected by the executive director's decision to deny a petition for phased RACT or to deny a revision to an approved phased RACT petition may file a motion for reconsideration. The requirements of §50.39 of this title (relating to Motion for Reconsideration) apply. However, only a person affected may file a motion for reconsideration. Approved petitions for phased RACT may be revised by the executive director upon a showing of just cause by the applicant.

(9) Approval of a phased RACT schedule by the executive director does not waive any applicable federal requirements or eliminate the need for approval by EPA.

(10) 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 owner or operator of a source located in the Dallas/Fort Worth ozone nonattainment area affected by the provisions of this chapter who determines that compliance by March 31, 2001, 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 by August 1, 2000, or as soon as possible after such date upon a demonstration by the owner or operator that the petition was not submitted by August 1, 2000 due to unforeseen circumstances.

(2) The owner or operator of the affected unit or units shall submit information in the petition to the executive director and a copy to the EPA regional office in Dallas which will demonstrate all of the following:

(A) ERCs or DERCs, in accordance with §101.29 of this title, are not reasonably available in an amount equal to the quantity of emission reductions required under this chapter. If ERCs or DERCs are reasonably available, they shall be applied to meet the emission reductions required under this chapter, in accordance with §117.570 of this title and §101.29 of this title.

(B) compliance by March 31, 2001, is impracticable due to the unavailability of nitrogen oxides (NO_x) abatement equipment, engineering services, or construction labor; system unreliability; manufacturing unreliability; equipment unreliability; or other technological and economic factors as the executive director determines are appropriate;

(C) there is a proposed stage-by-stage program for compliance and clearly specified compliance milestones for each unit;

(D) there is a commitment to implement the portion of the phased RACT petition that can be implemented by March 31, 2001; and

(E) the final compliance date specified in the petition shall be as soon as practicable, but in no case later than June 30, 2002, except as approved by the executive director.

(3) Each petition for phased RACT shall contain the information required by at least one of the following criteria.

(A) If compliance by March 31, 2001, is impracticable due to the unavailability of NO_x abatement equipment, engineering services, or construction labor, the following information shall be included in the petition for phased RACT:

(i) a list of the company names, addresses, and telephone numbers of vendors who are qualified to provide the services and equipment capable of meeting the applicable emission limitation under this chapter and who have been contacted to obtain the required services and equipment. A copy of the request for bids along with the dates of contact shall also be provided to show a good-faith effort to obtain the required services and equipment necessary to meet the requirements of this chapter by March 31, 2001; and

(ii) copies of responses from each of the vendors listed in clause (i) of this subparagraph showing that they cannot provide the necessary services and install the appropriate equipment in time for the unit to comply by March 31, 2001. Such responses shall include the reasons why the services cannot be provided and why the equipment cannot be installed in a timely manner.

(iii) if work on the project will be provided by the owner or operator, the petition for phased RACT shall include documentation that the necessary NO_x abatement equipment, engineering services, or construction labor could not be obtained in a timely manner from either in-house or external sources, as well as a detailed design or installation schedule for the required services or equipment to be provided by the owner or operator.

(B) If compliance by March 31, 2001, is impracticable due to system unreliability for sources in the utility industry, defined as the inability or threatened inability of a utility grid system to fulfill obligations to supply electric power, the following information shall be included in the petition for phased RACT:

(i) standard load forecasts, based on standard forecasting models available throughout the utility industry, applied to the period March 31, 1999 - March 30, 2001;

(ii) outage schedule for all units in the utility grid to which the subject unit belongs; and

(iii) specific reasons why an outage for the purpose of installing NO_x emission control equipment cannot be scheduled by March 31, 2001.

(C) If compliance by March 31, 2001, is impracticable due to manufacturing unreliability, defined as the inability or threatened inability of a source to fulfill contractual obligations to supply a product or products, the following information shall be included in the petition for phased RACT:

(i) certification by an authorized official of the company showing manufacturing obligations for which the company is contractually obligated. Manufacturing obligation information shall include copies of contracts signed by an authorized official of the company or similar documentation and shall exclude commercially sensitive information;

(ii) historical and planned outage schedules for all units whose manufacturing capacity would be affected by the outage of the affected unit; and

(iii) specific reasons why an outage for the purpose of installing NO_x emission control equipment cannot be scheduled by March 31, 2001.

(D) If compliance by March 31, 2001, is impracticable due to equipment unreliability, defined as the reduced availability and operating reliability of a unit resulting from the operation of NO_x control equipment on that unit, the following information shall be included in the petition for phased RACT:

(i) specific reasons why the new NO_x control equipment will reduce the current reliability of the operating unit;

(ii) historical availability and forced outage data expressed as annual percentages and the differences in each expected with the new NO_x control equipment. Availability is defined as the sum of hours the equipment is in service plus the hours the equipment is not in service, but available for service, divided by the number of hours in the reporting period. A forced outage is defined as down time which occurs as a result of a trip, emergency shutdown, or unplanned maintenance;

(iii) most recent operating history available from the vendor for the new NO_x control equipment, including actual test operating hours, actual load during testing, and specific problems that resulted in lost availability; and

(iv) reasons why the NO_x control technology is not considered proven including vendor test and commercial operating data, if available from the vendor.

(E) If compliance by March 31, 2001, is impracticable due to other technical factors, the petition for phased RACT shall contain such documentation as the executive director establishes is appropriate for such technical factors.

(F) If compliance by March 31, 2001, is unreasonable due to economic considerations, excluding the time value of money, the petition for phased RACT shall contain the following information showing comparisons of the cost of compliance by November 15, 1999 and the cost of compliance by the final compliance date specified in the petition:

(i) the costs of additional outages, if applicable, necessitated by compliance with the emission specifications of this chapter by March 31, 2001, as demonstrated by comparison to costs of actual historical and planned outages;

(ii) comparisons of the cost of obtaining the NO_x abatement equipment, engineering services, or construction labor necessary to comply by March 31, 2001, and the cost of obtaining the NO_x abatement equipment, engineering services, or construction labor by the final compliance date specified in the petition. Copies of legally binding contracts, signed by an authorized official of the company, shall be submitted to document these costs. If the required NO_x abatement equipment, engineering services, or construction labor will be provided by the owner or operator, as provided for in paragraph (4) of this subsection, certification by an authorized official of the company may be submitted in lieu of contracts to document these costs; or

(iii) other economic factors, documented as the executive director establishes is appropriate for such economic factors.

(4) All petitions for phased RACT shall include a list of the company names, addresses, and telephone numbers of persons who own or control ERCs or DERCs, and who have been contacted in efforts to obtain the ERCs or DERCs for purposes of meeting the emission reductions required under this chapter. For each person or company contacted, the list shall contain a description of the information obtained, including but not limited to the date of contact, availability of the ERCs or DERCs, sale price requested by the owner or controller of the ERCs or DERCs, sale price offered by the prospective buyer of the ERCs or DERCs, and an explanation of the reasons why the ERCs or DERCs, if available, were not purchased for purposes of meeting the emission reductions required under this chapter.

(5) All petitions for phased RACT shall include copies of legally binding contracts with the primary vendors for each project, signed by an authorized official of the company, showing a detailed design or installation schedule for the required services or equipment to be provided by that vendor, with a completion date no later than June 30, 2002, except as approved by the executive director. Any commercially sensitive financial information or trade secrets should be excised from the contracts.

(6) Within 30 days of receiving a petition for phased RACT, the executive director shall inform the applicant in writing that the petition is complete or that additional information is required. If the petition is deficient, the notification shall state any additional information required. The requested information correcting the deficiency shall be received by the executive director within 30 days of the date of the letter notifying the applicant of the deficiency.

(7) The executive director shall approve or deny the petition within 90 days of receiving an administratively complete phased RACT petition. The executive director shall approve a petition for phased RACT if the executive director determines that compliance is not practicable by March 31, 2001, because of either the unavailability of nitrogen oxides abatement equipment, engineering services, or construction labor; system unreliability; manufacturing unreliability; equipment unreliability; or other technological and economic factors as the executive director determines are appropriate.

(8) Any person affected by the executive director's decision to deny a petition for phased RACT or to deny a revision to an approved phased RACT petition may file a motion for reconsideration. The requirements of §50.39 of this title apply. However, only a person affected may file a motion for reconsideration. Approved petitions for phased RACT may be revised by the executive director upon a showing of just cause by the applicant.

(9) Approval of a phased RACT schedule by the executive director does not waive any applicable federal requirements or eliminate the need for approval by EPA.

(10) 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.

SUBCHAPTER E : GAS-FIRED STEAM GENERATION

§117.601

STATUTORY AUTHORITY

The amendments are adopted under the Texas Health and Safety Code, the Texas Clean Air Act (TCAA), §382.012, which requires the commission to develop a general, comprehensive plan for the proper control of the state's air; §382.016, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; and §382.051(d), which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.601. Gas-Fired Steam Generation.

(a) Subsections (b), (c), and (d) of this section (emission specifications adopted by the Texas Air Control Board in 1972) 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 also subject to the emission limitations of Subchapter B of this chapter (relating to Combustion at Existing Major Sources), the emission limitations of this section shall no longer apply after the applicable final compliance date specified in Subchapter D of this chapter (relating to Administrative Provisions).

(b) - (e) (No change.)