The Texas Natural Resource Conservation Commission (TNRCC or commission) proposes amendments to §§117.101, 117.103, 117.105, 117.107, 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, 117.208, 117.209, 117.211, 117.213, 117.215, 117.217, 117.219, 117.221, and 117.223, concerning Commercial, Institutional and Industrial Sources; and §§117.510, 117.520 and 117.570, concerning Administrative Provisions. The commission also proposes new §§117.104, 117.106, 117.108, 117.116, 117.206, and 117.216, concerning Combustion at Existing Major Sources. In addition, the commission proposes to repeal §117.109, concerning Initial Control Plan Procedures, and §117.601, concerning Gas-Fired Steam Generation. The proposed changes to Chapter 117 and to the State Implementation Plan (SIP) would require certain electric utility and industrial, commercial, and institutional (ICI) boilers in the Beaumont/Port Arthur (BPA) and Dallas/Fort Worth (DFW) ozone nonattainment areas to meet new emission specifications and other requirements in order to reduce nitrogen oxides (NO_x) emissions and ozone air pollution. The changes would also require certain process heaters in BPA and lean-burn engines in DFW to meet new emission specifications and other requirements in order to reduce NO_x emissions and ozone air pollution. The commission proposes these amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and to the SIP as essential components of and consistent with the SIP that Texas is required to develop under Federal Clean Air Act (FCAA), §110 to demonstrate attainment of the National Ambient Air Quality Standard (NAAQS) for ozone.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULES: BPA

The BPA ozone nonattainment area, an area defined by Hardin, Jefferson, and Orange Counties, is currently designated moderate under the FCAA and thus was required to attain the one-hour ozone standard by November 15, 1996. BPA did not attain the standard by that date and also did not attain the standard by November 15, 1999, the attainment date for serious areas. The United States Environmental Protection Agency (EPA) is authorized to redesignate an area to the next higher classification ("bump up") if it fails to attain by the required date.

However, as an alternative to bump-up, EPA policy allows consideration of the effect of transport of ozone or its precursors from an upwind area. The HGA ozone nonattainment area is upwind of BPA and influences BPA's air quality to such an extent that without reductions from HGA, BPA may not be able to attain the standard solely from its own local reductions. EPA's revised transport policy allows a downwind area such as BPA to have its attainment date extended to no later than the attainment date for the upwind area, without being bumped up.

On April 16, 1999, EPA published notice in the *Federal Register* (64 FR 18864) that for BPA to take advantage of this policy, the commission must submit to EPA an acceptable SIP revision (by November 15, 1999) which includes any local control measures needed for expeditious attainment and proof that all applicable local control measures required under the moderate classification have been adopted. On May 19, 1999, EPA informed the commission by letter that an approvable attainment demonstration would need to consider modeling for the September 6, 1993-September 11, 1993 ozone episode. The influence of HGA emissions on BPA ozone levels is less pronounced during this period and the modeling demonstrated the need for more NO_x reductions in BPA in order for the area to attain the 1-hour ozone standard.

The emission reduction requirements proposed in this notice are the outcome of a development process which involved the EPA, TNRCC, local elected officials, citizens, industrial stakeholders, air quality researchers, and hired consultants. The amount of NO_x reductions required for the area to attain the ozone NAAQS has been estimated by extensive use of sophisticated air quality grid modeling, which because of its scientific and statutory grounding, is the chief policy tool for designing emission reductions. The FCAA, §182(c)(2) requires the use of photochemical grid modeling for ozone nonattainment areas designated serious, severe, or extreme. The modeling has been conducted with input from a technical advisory committee including members of the BPA industrial community. Varying degrees of point source reductions were analyzed in at least seven iterations of modeling, to test the effectiveness of different NO_x reductions.

The emission reductions necessary for the BPA attainment demonstration SIP are based on the modeling episode from September 6, 1993 - September 11, 1993, and the controlling day, September 10, 1993. Modeling for the controlling day indicates a point source NO_x reduction of roughly 40% from 1997 levels, or about 60 tons per day, is necessary. The commission believes that the modeled point source BPA NO_x rules, coupled with numerous additional reductions, including on-road and non-road reductions within the area, and reductions in all categories outside the area, and the design value calculations in the SIP being proposed for public hearing concurrently with these proposed rules, demonstrate that BPA will attain the 1-hour ozone standard by 2007.

The proposed rulemaking represents “Phase II” of the state’s NO_x rulemaking activities for the BPA attainment demonstration. The adopted “Phase I” rules, for lean-burn engines in BPA, and a concurrent SIP revision, were submitted to EPA on November 12, 1999. The state committed in that SIP revision to develop additional NO_x rules as needed for attainment in BPA. These “Phase II” rules needed for attainment are expected to be submitted to EPA in April, 2000.

The attainment demonstration modeling produces a target emission rate of about 95 tons of NO_x per day in 2007 from industrial point sources. The staff analyzed the most recent available point source NO_x emissions inventory, from 1997, categorizing the emitting sources by equipment type to identify how to reasonably obtain the necessary reductions. In the Tables and Graphics section of this notice, the table titled “1997 BPA Point Source NO_x by Unit Type” indicates the relative proportion of emissions according to equipment category.

Table: 30 TAC §117 Preamble

1997 BPA Point Source NO_x by Unit Type

Unit Type	# FIN	# EPN	TPY	TPOD	% Total	Running Total
Industrial Boilers	117	113	14,626	41.4	26.7%	27%
Process Heaters	406	387	9,204	26.7	17.3%	44%
Electric Utility Boilers	9	12	7,190	26.7	17.3%	61%
Engines	152	160	5,941	18.8	12.1%	73%
Refinery Catalytic Crackers	4	5	4,555	12.9	8.3%	82%
Industrial Boilers - RCRA BIF	11	11	4,327	11.9	7.7%	89%

Unit Type	# FIN	# EPN	TPY	TPOD	% Total	Running Total
Gas Turbines	14	15	2,255	6.7	4.3%	94%
Incinerators	47	38	1,553	4.2	2.7%	96%
Kilns	5	8	906	2.7	1.7%	98%
Flares	244	132	353	0.9	0.6%	99%
Other	100	100	544	1.8	1.2%	100.0%
Total	1100	1000	51,500	154.9	100%	

The #FIN column gives an approximate number of pieces of equipment in each category. Much of the equipment listed in the inventory is small or does not operate enough to make NO_x regulation cost effective.

The table shows that emission reductions approaching the 60 tons per day required by the attainment demonstration necessitate further reductions from the largest categories, including industrial boilers, process heaters, electric utility boilers and engines.

The boilers and process heaters in BPA are almost entirely gas-fired. Combustion modifications such as low-NO_x burners for boilers and heaters, and flue gas recirculation (FGR) for gas-fired boilers are effective control technologies for these sources. Based on experience with best available control technology (BACT) NO_x limits, retrofit requirements in California, and information in the literature, the current Chapter 117 NO_x reasonably available control technology (RACT) rules for boilers and process heaters leave room for significantly lower NO_x limits without having to resort to more expensive post-combustion, flue gas cleanup type controls. For instance, California boiler retrofit rules at 0.036 pound NO_x per million Btu (lb NO_x/MMBtu) generally do not require flue gas cleanup, and in Texas, a BACT level of 0.06 lb NO_x/MMBtu has not required flue gas cleanup.

The stationary engine category will be greatly reduced after both the 1999 Chapter 117 compliance date for rich-burn engines in BPA, and 2001 for lean-burn engines in BPA have passed. Stationary engine NO_x is presently regulated by a combination of Chapter 117 NO_x RACT and Chapter 116 air quality permits to such an extent that the opportunity for reasonably requiring much further reduction is limited.

The turbine category is also presently regulated by RACT, with a November 15, 1999 compliance date, and air permits to the extent that there is limited opportunity for obtaining more NO_x reduction in the category. For example, lowering the existing 42 parts per million by volume (ppmv) NO_x RACT limit to 25 ppmv would produce only about an additional ton per day of NO_x reduction in the area. Further, the large gas turbines are entirely located at the four refineries and two largest chemical plants in the area, plants which will be required to produce the majority of the necessary NO_x reductions from boilers and heaters under the proposed rule.

Of the categories not regulated by Chapter 117 contributing more than 1% of the total point source emissions, including refinery catalytic crackers, hazardous waste-fired boilers and industrial furnaces (BIFs), incinerators, and kilns, there are technical problems that make requiring NO_x control less cost effective than for the larger emission categories. Post-combustion control is probably the only effective reduction technology for many of the sources in these categories. In addition, with the exception of the kilns, the unregulated equipment in these categories is largely located at major sources which will be required to reduce emissions from boilers and process heaters under the proposed rule.

To analyze the reductions obtainable by potential emission rate limits (lb NO_x/MMBtu), the commission gathered the emission rate factors used to calculate 1997 ozone season emissions for the large boilers, heaters and turbines at the major sources in BPA. The information was compiled in a spreadsheet, allowing reductions from a rate limit applied to an equipment category to be calculated either as a number of tons NO_x per day reduced or as a percentage reduction from the category. Because the attainment demonstration modeling was based on 1993 emissions, the 1997 emission rate reductions were applied to the modeling inventory as percent reductions.

Commission staff met twice in September 1999 with representatives of the major NO_x sources in BPA to negotiate proposed NO_x emission limits for the BPA ozone attainment demonstration. These negotiations resulted in the proposed limits of 0.10 lb NO_x/MMBtu for gas-fired boilers and 0.08 lb NO_x for gas-fired process heaters.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULES: DFW

The DFW ozone nonattainment area, an area defined by Collin, Dallas, Denton, and Tarrant Counties, was originally designated “moderate” under the FCAA Amendments of 1990 and thus was required to attain the one-hour ozone standard by November 15, 1996. As required by the FCAA, the state submitted an attainment demonstration plan in 1994 which projected attainment of the ozone air quality standard by 1996. This plan was based on a volatile organic compounds (VOC) reduction strategy.

DFW did not attain the ozone standard in 1996. The EPA is authorized to redesignate an area to the next higher classification ("bump up") if it fails to attain by the required date. In March 1998, in accordance with FCAA, §181(b)(2), the EPA reclassified the DFW area from moderate to serious, based on monitored exceedances of the ozone standard between 1994 and 1996. The reclassification required the state to submit a revised SIP that demonstrates that the ozone standard will be met in DFW by November 15, 1999. Because the DFW area continued to exceed the ozone standard in 1999, the EPA may bump up the area to the severe classification. Regardless, the EPA and FCAA, §110 and §172(a)(2), require the state to submit a revised SIP which demonstrates that the area will attain the ozone standard as expeditiously as practicable. The rules proposed for DFW in this notice are one element of the ozone attainment demonstration SIP for DFW being proposed for public hearing and comment concurrently in this issue of the *Texas Register*. The commission plans to submit this SIP to the EPA by April, 2000.

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 newer modeling since 1996 has shown that NO_x reductions will be necessary to attain the ozone standard in the DFW area. The current modeling also shows that achieving the ozone standard in DFW will require strenuous effort because the area's rapid growth has resulted in increasing amounts of emissions due to increased levels of activity in the area. The emissions from increased activity are offsetting emission reductions that are being achieved from new emission standards applicable to the on-road and non-road engine source categories which dominate the emissions inventory in DFW.

The emission reduction requirements proposed in this notice are the outcome of a development process which involved the EPA, TNRCC, local elected officials, citizens, industrial stakeholders, air quality researchers, and hired consultants. The amount of NO_x reductions required for the area to attain the ozone NAAQS has been estimated by extensive use of sophisticated air quality grid modeling, which because of its scientific and statutory grounding, is the chief policy tool for designing emission reductions. The FCAA, §182(c)(2) requires the use of grid modeling for ozone nonattainment areas designated serious, severe, or extreme. The modeling has been conducted with input from a technical advisory committee including members of the DFW industrial community. Several variations of point source reductions have been analyzed in at least thirty iterations of modeled control strategies, to test the effectiveness of different NO_x reductions.

The attainment demonstration modeling being submitted for public hearing and comment concurrently with these proposed rules shows that close to the maximum NO_x reductions practicably achievable are necessary from each emission source category in order for DFW to achieve the ozone NAAQS by 2007. Major stationary sources contribute about 15% of the total NO_x in the DFW area during the ozone season, and therefore must be included in these maximal efforts. The proposed NO_x emission limits for electric utility and large ICI boilers in this rule making approach the maximum practicable emission reductions for these sources. The commission seeks comment on whether the proposed NO_x emission limits for electric utility and large ICI boilers should also be required in the full (12 county) DFW SMSA. The proposed NO_x emission limits for lean-burn engines effectively limits the emissions from an unregulated category of major stationary sources of NO_x in DFW.

Another purpose of these proposed revisions to Chapter 117 and to the SIP is to extend NO_x RACT requirements to lean-burn engines in DFW. The 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 EPA requires photochemical grid modeling to demonstrate whether the §182(f) NO_x measures would contribute to ozone attainment. On June 21, 1999, the EPA rescinded a §182(f) exemption from NO_x measures for DFW. EPA's rescission was based on its finding that NO_x reductions in DFW are necessary for attainment of the ozone standard.

SECTION BY SECTION ANALYSIS

The primary purpose of the proposed revisions is to establish new emission limits for the ozone attainment demonstrations. However, many of the proposed rule changes discussed in the following section of the preamble are designed to allow the use of existing NO_x RACT rule mechanisms to be used for compliance with the proposed emission limits. These changes strive to maintain consistency with the existing requirements. Where there may be reasons to adjust existing compliance requirements, the reasons for the proposed changes are discussed.

A proposed change to Subchapter B, Division 1, relating to Utility Electric Generation, changes the title of the division to "Utility Electric Generation in Ozone Nonattainment Areas." The revised title distinguishes between rules applicable in the nonattainment areas and rules that are proposed for attainment counties in east and central Texas, proposed concurrently in a separate section of this issue of the *Texas Register*.

The proposed changes to §117.101, concerning Applicability, and §117.103, concerning Exemptions, update the sections to reflect the proposed new names of cross referenced sections. An additional change to §117.101 would clarify that the requirements of the division will continue to apply to any successor in ownership of a municipality or Public Utility Commission (PUC) of Texas regulated utility. The new owner does not need to be a municipality or a PUC regulated utility for the requirements to apply. An additional change to §117.103 would delete the cross reference to §117.109, concerning Initial Control Plan Procedures, because the section is no longer needed and is proposed for repeal.

The proposed new §117.104, concerning Gas-fired Steam Generation, relocates existing emission NO_x specifications for electric utility boilers in certain ozone nonattainment counties from §117.601. The change brings the Chapter 117 utility boiler emission specifications for DFW into consecutive sections within a common subchapter. The minimal NO_x standards of §117.601 have been applicable in a thirty-one county regional area comprising the Houston and Dallas Air Quality Control Regions, since 1972. The limits would cease to apply in DFW on the March 31, 2001 NO_x RACT compliance date for DFW specified in §117.510(b)(1). The NO_x RACT limits of §117.105 superseded §117.601 in HGA on November 15, 1999, so the eight HGA counties are not listed in proposed §117.104. Section 117.601 requirements for the affected attainment counties are proposed to be relocated to a new division for electric utility generation in east and central Texas, in a separate section of this issue of the *Texas Register*.

A proposed change to §117.105, concerning Emission Specifications, revises the section title to "Emission Specifications for RACT," to distinguish the RACT limits in this section from the proposed tighter emission limits necessary to demonstrate attainment. The proposed change to §117.105(h), corrects a previous drafting error by clarifying that the carbon monoxide (CO) emission limit for utility boilers applies at 3.0% oxygen, on a dry basis. The change makes the form of the CO emission limit for electric utility boilers consistent with the CO limit for ICI boilers as intended in the original NO_x RACT rulemaking. It is standard practice in the field of air pollution control to reference concentration limits to a flue gas oxygen concentration, to address the effects of dilution.

The proposed new §117.106, concerning Emission Specifications for Attainment Demonstrations, specifies new NO_x limits for electric utility boilers located in BPA and DFW. The proposed limits are essential components of and consistent with the BPA and DFW ozone attainment demonstration SIPs, being noticed for public hearings and comment concurrently in a separate section of this issue of the *Texas Register*. The proposed emission limits and ozone attainment demonstration SIPs are required by the FCAA, §110 and §182, which require states to submit SIPs to the EPA which contain enforceable measures to achieve the NAAQS.

The proposed limit of §117.106(a) for utility boilers in BPA is part of a larger set of emission reduction measures necessary for the BPA attainment demonstration SIP. The larger context of development of the proposed NO_x emission limit for utility boilers in BPA is discussed in the background for BPA section of this preamble notice. The proposed limit of 0.10 lb NO_x/MMBtu generates a 12.1 tons per day NO_x reduction from utility boilers in BPA, based on the 1997 emission inventory. As discussed in the cost note section of this preamble, because four of the five gas-fired utility boilers affected by the proposed limit are tangential-fired, the limit is expected to be achievable with combustion modification techniques, such as separate over-fired air and FGR. Combustion modifications for the wall-fired unit may include low-NO_x burners.

Although the NO_x standards of §117.106(a) and (b) are proposed in the traditional heat input-based format of lb NO_x/MMBtu, the commission may adopt the emission standards in the output-based format of pounds NO_x per megawatt hour. Output based standards allow the source owner to improve the efficiency of the regulated equipment. By harmonizing the environmental and economic goals more closely, output based standards can lower the cost of regulation compared to input-based standards. The numeric value of equivalent output based emission standards can be calculated readily from electric production records for the baseline emission period. However, because the commission also proposes to allow emission cap compliance, which also permits efficiency improvements to contribute toward rule compliance and offers even more flexibility, an output-based format would only be useful if a utility were likely to choose the option of direct emission compliance with the standard. The commission seeks public comment on expressing the §117.106 NO_x limits in output-based format.

The proposed 24-hour averaging period for the NO_x emission limits of §117.106(a) and (b) is consistent with existing NO_x RACT emission limits for electric utility boilers. The 24-hour average emission limit in both NO_x RACT and these rules is designed to limit the amount of NO_x allowed in a 24-hour period, in order to control peak ozone, which forms on a daily cycle.

The proposed limit of §117.106(b) for utility boilers in DFW is part of a larger set of emission reduction measures for the DFW attainment demonstration SIP. The larger context of development of the proposed NO_x emission limit for utility boilers in BPA is discussed in the background for DFW section of this preamble notice. The proposed limit of 0.033 lb NO_x/MMBtu is based on an 88% emission reduction, calculated from the average emissions of the utility boilers in DFW during the baseline period proposed in §117.108, concerning System Cap. As discussed in the cost note section of this preamble notice, the proposed 88% NO_x reduction is expected to necessitate selective catalytic reduction (SCR) on most of the utility boilers in the DFW area.

The proposed emission limits of §117.106(c) address pollutants which may increase as an incidental result of compliance with the proposed NO_x limits. The proposed CO limit is consistent with the existing CO limit of §117.105(i) because nothing in these rules necessitates changing the existing limit. The proposed ammonia limit of 5 ppm is lower than the existing limit of §117.105(j). The proposed ammonia limit is supported by information from SCR vendors and ammonia test data for gas-fired boilers using SCR, not available when the original NO_x RACT rules were adopted in 1993. The test data are reported in Table 2-5 of "*Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers*," issued by the Northeast States for Coordinated Air Use Management (NESCAUM) and the Mid-Atlantic Regional Air Management Association (MARAMA) (June 1998). It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission proposes to exclude these related pollutant limits from the attainment demonstration SIP, in order to simplify the approval process for alternative emission specification under §107.121. This step would eliminate the need for case specific SIP revisions by EPA to complete the approval of an alternate CO or ammonia limit.

The proposed §117.106(d) would allow the compliance flexibility of the proposed new system cap in §117.108 and the existing emission trading provisions in §117.570 to be used to establish compliance with the proposed attainment demonstration NO_x limits. The commission seeks comments on possible additional flexible methods to achieve compliance with the proposed emission limits for municipalities and other affected electric utility sources.

A proposed change to §117.107(a), concerning Alternative System-Wide Emission Specifications, updates the section to reflect a proposed new name of a cross referenced section. The proposed change to §117.107(a)(1)(A), corrects a cross reference to the peaking gas turbine emission NO_x limits. The peaking gas turbine emission limits were moved from §117.105(h) and (i) to §117.105(g) in a previous rulemaking (24 *TexReg* 1784).

The commission does not propose to allow the use of §117.107 as an alternative for complying with the proposed §117.106 emission specifications for attainment demonstrations. Section 117.107 emission averaging does not address the effects of activity level, and may not produce the intended reductions that would be achieved with direct compliance by all units or flexible compliance with an emission cap. Under §117.107, higher emissions will result if units selected for less control are subsequently operated more, or if units selected for more control are subsequently operated less. The proposed §117.106 emission limits will necessitate installation of flue gas cleanup emission controls on a number of units. As a result, these units are likely to have higher operating costs than units operating with only combustion controls, creating an economic incentive to operate the best-controlled units less and to produce greater emissions. Instead of system-wide emission averaging for compliance with the proposed new NO_x limits, the commission proposes a system-wide cap. The system cap avoids the issue of equivalent emission reductions that is associated with emission averaging.

The proposed new §117.108, concerning System Cap, would create a flexible new alternative to direct compliance with the NO_x emission specifications proposed in §117.106. The proposed section is patterned on the existing source cap compliance option in §117.223 for ICI combustion sources. The proposed system cap sets limits on total pounds of NO_x allowed to be emitted by an electric utility system. A cap has the advantage over rate-based standards of allowing the source owner to control the activity levels of the regulated equipment as a means of compliance. This means that a company's compliance measures may include installing less extensive emission controls on a piece of equipment and choosing to operate it less, or upgrading its efficiency to require less fuel firing. The majority of the electric utility boilers in DFW and the five operating boilers in BPA units are currently monitoring NO_x continuously under the federal acid rain rules of 40 CFR 75; the smaller ones which are not, are required to monitor NO_x under existing RACT requirements of Chapter 117. The absence of additional costs for new NO_x monitors is expected to make the system cap an attractive option for electric utilities.

The proposed averaging period for the NO_x system cap includes a 30-day rolling average daily emission limit and a maximum daily limit, consistent with the existing NO_x RACT source cap limits for ICI sources. The 30-day rolling average is normally the more stringent limit, because it is designed to achieve the 88% reduction from historical actual emissions in the three highest ozone months. The proposed daily maximum limit, based on an 88% reduction from maximum rated capacity, is designed to limit the amount of NO_x allowed in a single day in order to control ozone peaks which form within a daily cycle. The maximum daily limit is less stringent than the 30-day rolling average because even on the days of highest demand, the system does not operate continuously at maximum rated capacity the entire day.

The proposed baseline period for H_i, the historical heat input used in the 30-day rolling average of §117.108(c)(1), is July, August, and September 1996, 1997, and 1998. The baseline is intended to represent typical utility electric demand and emissions during the peak ozone formation months. An average over three years limits the influence of one particular year on the design value. Fluctuations in ambient temperature patterns often cause significant annual variation in electric demand. For DFW, the ozone episodes chosen to be modeled in the current attainment demonstration SIP occurred in 1996 and 1997, so the proposed baseline overlaps with the modeled periods. For BPA, the ozone episodes chosen to be modeled in the current attainment demonstration SIP occurred in August and September 1993, so the proposed BPA baseline does not overlap with the modeled periods. The commission seeks comment on the most appropriate baseline period for the historical heat input in §117.108(c)(1).

Section 117.108 as proposed does not require the inclusion of new electric generating units in the system cap. This requirement is unnecessary because the nonattainment permit rules in 30 TAC 116, concerning Control of Air Pollution by Permits for New Construction or Modification, require new or modified major emissions sources to provide emissions offsets for significant new NO_x emissions so as not to interfere with the NO_x emission budget established in the ozone attainment demonstration SIP.

The commission proposes repeal of §117.109, concerning Initial Control Plan Procedures. This section is no longer needed because the required initial control plans were submitted in 1994 and the NO_x testing required in those plans is not cross referenced in §117.570, concerning Trading.

Proposed changes to §117.111, concerning Initial Demonstration of Compliance, update the section to reflect the proposed new names of the rule division and a cross referenced section. In §117.111(a), the cross reference to test schedules is broadened to the entirety of §117.510, concerning Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas, because initial demonstration of compliance testing is proposed for the §117.106 emission limits. New §117.111(d)(3) specifies the procedure for demonstrating initial compliance with the proposed emission cap of §117.108.

The proposed changes to §117.113, concerning Continuous Demonstration of Compliance, update the section to reflect the proposed new names of the rule division and cross referenced sections. In §117.113(f), the cross reference to emission specifications is broadened to the entirety of the rule division in order to require continuous demonstration of compliance testing with the proposed §117.106 emission limits. Similarly, in §117.113(j), the cross reference to emission specifications is broadened to the entire rule division to ensure that loss of exemption requirements also apply to the §117.106 limits.

The proposed changes to §117.115, concerning Final Control Plan Procedures, modifies the section title to “Final Control Plan Procedures for RACT,” and a rule cross reference, to distinguish the compliance report information required for RACT in this section from the proposed information for attainment demonstration emission limits in the next section.

The proposed new §117.116, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, specifies certain information for showing compliance with the attainment demonstration emission specifications of §117.106, to be included in a report submitted to the executive director. The proposed requirements are parallel to existing requirements in §117.115 and §117.215, concerning Final Control Plan Procedures.

The proposed changes to §117.117, concerning Revision of Final Control Plan, §117.119, concerning Notification, Recordkeeping and Reporting Requirements, update the sections to reflect the proposed new names of cross referenced sections. An additional proposed change to §117.119(d) defines excess emissions under the utility system cap, using parallel language from the definition for ICI sources, in §117.219(d)(1).

A proposed change to §117.121, concerning Alternative Case Specific Specifications, updates the section to reflect the proposed new names of cross referenced sections. Another proposed change to §117.121 adds reference to the CO and ammonia limits of §117.106(c), which would allow alternative emission specifications to be established on a case specific basis for these pollutants.

A proposed change to Subchapter B, Division 2, relating to Industrial, Commercial, and Institutional Sources, changes the number and title of the division to "Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas." The new title distinguishes between rules applicable in the nonattainment areas and rules that would apply to cement kilns in the east and central Texas region, proposed concurrently in a separate section of this issue of the *Texas Register*.

The proposed changes to §117.201, concerning Applicability, and §117.203, concerning Exemptions, update the sections to reflect the proposed new names of cross referenced sections.

A proposed change to §117.205, concerning Emission Specifications, revises the section title to "Emission Specifications for RACT," to distinguish the RACT limits in this section from the proposed tighter emission limits necessary to demonstrate attainment of the ozone NAAQS. The proposed change to §117.205(a)(3) updates the name of a cross referenced section and the proposed change to §117.205(g) revises the cross reference from division to section level to accommodate proposed new emission specifications within the division.

The proposed new §117.206, concerning Emission Specifications for Attainment Demonstrations, specifies new NO_x limits for gas-fired boilers and process heaters at major sources of NO_x in BPA and gas-fired boilers and lean-burn, gas and gas/liquid-fired engines at major sources of NO_x in DFW. The proposed limits are essential components of and consistent with the BPA and DFW ozone attainment demonstration SIPs being noticed for public hearings and comment concurrently in a separate section of this issue of the *Texas Register*.

The proposed emission specification of 0.10 lb NO_x/MMBtu for gas-fired boilers in §117.206(a)(1) and 0.08 lb NO_x/MMBtu for gas-fired process heaters in §117.206(a)(2) generate an additional 18.6 tons per day NO_x reductions from major NO_x sources in BPA, based on the 1997 emission inventory. In order to achieve these reductions, the allowances for heat release rate, firebox temperature, and fuel hydrogen content under the §117.205 NO_x RACT rule have been eliminated. Combustion modifications, including

FGR for boilers and low-NO_x burners for boilers and heaters, can provide the bulk of the emission reductions required by this standard. Individual units for which this technology is too expensive or unable to achieve the standard can be brought into compliance through a plant-wide average, source cap, or emission trade, as allowed by §117.206(e).

The proposed emission specification of 30 ppm NO_x for gas-fired boilers rated at more than 40 MMBtu/hr in §117.206(b)(1) generates an additional 0.7 ton per day NO_x reductions in DFW, calculated from the 1996 emission inventory. Analysis of the 1996 emissions inventory indicates that the proposed rule would affect 7 boilers located at three major sources in the DFW area. These boilers do not operate with air preheat, and FGR is anticipated to be capable of providing the emission reductions necessitated by the proposed limit. The limit is equivalent to the limit set and achieved for emission control retrofit of gas-fired boilers in a number of California districts, including the Bay Area and South Coast Air Quality Management Districts. The concentration format used in California and proposed here is simpler and more descriptive than the heat input format, which is more appropriate for large plants which are more likely to apply emission averaging or source caps for compliance. The 30 ppmv limit is equivalent to 0.036 lb NO_x/MMBtu.

The proposed emission specification of 2 grams NO_x per horsepower-hour (g NO_x/hp-hr) for lean-burn, gas-fired and gas/liquid-fired engines in §117.206(b)(2) generates an additional 0.9 ton per day NO_x reduction in DFW based on the 1996 emission inventory. In addition to providing NO_x reductions necessary for the attainment demonstration required under the FCAA, §110(k), the proposed emission limit would implement NO_x RACT for lean-burn engines in DFW, as required by the FCAA, §182(f).

Analysis of the 1996 emissions inventory indicated that the proposed rule would affect 3 engines located at two major sources in DFW. These engines are capable of meeting the emission limits using low emission combustion (LEC) modifications. One of the sources, a gas compressor station with two White-Superior 8GT825 engines, is not currently operating. The engines could maintain exempt status under the §117.203(6)(B) exemption for less than 850 hours per year of operation. The proposed rule ensures that if the engines were to operate above the exemption level of 850 hours per year in the future, the emissions from these engines would be minimized and the reductions would remain creditable to the SIP. The proposed limit is consistent with retrofit limits for lean-burn engines in several other serious and above ozone nonattainment areas.

The proposed NO_x emission limit averaging times in §117.206(c) are consistent with the averaging times for NO_x RACT compliance, in §117.205(b)(7). Units with NO_x emission monitors are capable of tracking emissions over time, and are allowed to demonstrate compliance on a 30-day average under this subsection.

The proposed emission limits of §117.206(d) address pollutants which may increase as an incidental result of compliance with the proposed NO_x limits. The proposed CO limit is consistent with the existing CO limit of §117.205(f) for RACT because nothing in these rules necessitates changing the existing limit. The proposed ammonia limit of 5 ppm is lower than the existing limit of §117.205(g). The proposed ammonia limit is supported by information from SCR vendors and ammonia test data for gas-fired boilers using SCR, not available when the original NO_x RACT rules were adopted in 1993. The test data are reported in Table 2-5 of "*Status Report on NO_x Control Technologies and Cost*

Effectiveness for Utility Boilers," NESCAUM/MARAMA (June 1998). It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission proposes to exclude these related pollutant limits from the attainment demonstration SIP, in order to simplify the approval process for alternative emission specification under §107.221. This step would eliminate the need for case specific SIP revisions to complete the approval of an alternate CO or ammonia limit.

The proposed §117.206(e) would allow the same compliance flexibility given to ICI sources under NO_x RACT to be given to ICI sources under the proposed attainment demonstration emission specifications. The commission proposes to allow the continued use of §117.207 plant-wide averaging (a form of emission trading) for the ICI sources for several reasons. First, distinct from the electric utility units, most of the industrial units do not have NO_x emissions monitors, so the plant-wide averaging option will be more economically attractive to some source owners than the source cap, which requires NO_x monitors. Second, unlike many of the electric utility boilers, the ICI boilers and heaters are not expected to require flue gas cleanup controls. The operating cost associated with combustion modification controls is not as likely to create a significant incentive to operate more controlled units less, as may be the case with operating cost associated with flue gas cleanup. Plant-wide emission averaging is worth maintaining because of its economic benefits.

The proposed exemptions in §117.206(f) are consistent with the NO_x RACT exemptions in §117.205(h), except for the proposed lowering of the applicability threshold to 40 MMBtu/hr of heat input capacity for boilers and heaters, which is necessary to achieve the reductions required by the attainment demonstration. The emission reductions identified in this proposal are sufficient to avoid requiring additional NO_x reductions from the BIFs, refinery catalytic cracking unit boilers and process vents, and kilns, which are among the sources exempted from Chapter 117 limits. As discussed in the preamble background, control of these sources creates technical and economic difficulties that make reglation of these sources less reasonable.

The proposed changes to §117.207(a) update a cross-referenced section name and add a cross reference to §117.206 to allow the section to be used as an alternative procedure for demonstrating compliance with the attainment demonstration emission specifications. The proposed change to §117.207(g)(4) and (h)(3) would not allow a higher NO_x limit with hydrogen fuel. This proposed revision, which is only relevant in BPA with its major source refineries and petrochemical plants, is necessary to achieve the reductions proposed for the attainment demonstration SIP for BPA. Proposed revisions to §117.207(f) would continue to allow certain units exempt from Chapter 117 NO_x limits to be brought into the rule as an alternative means of compliance. Opt-in units would no longer include the boilers and heaters rated between 40 and 100 MMBtu/hr which are subject to the proposed new attainment demonstration emission specifications. The proposed revisions to §117.207(f)(3) and (g) and new §117.207(i) would modify the provisions which require that the applicable limit for emission averaging is the lower of the Chapter 117 limit and the Chapter 116 limit, to specify revised dates for applicable Chapter 116 limits. These revised dates are consistent with the emission rates and reductions modeled for the sources in the attainment demonstration SIPs for BPA and DFW.

Proposed changes to §117.208, concerning Operating Requirements, and §117.209, concerning Initial Control Plan Procedures, would change or eliminate cross references to update to the newly named sections. The proposed change to §117.208 would allow fuel trim as an alternative to oxygen or CO trim. Fuel trim has been demonstrated as an effective control technique for natural gas fired boilers operating with FGR to achieve compliance with a 30 ppmv NO_x limit.

The proposed revisions to §117.209, concerning Initial Control Plan Procedures, would update the section to accommodate the revised names of sections. The commission does not propose repeal of §117.209 because the trading requirements in §117.570 rely on testing required under §117.209 to quantify emission credits. In contrast to the utility initial control plans, which are no longer of value, the initial control plans of the ICI sources cover units for which the initial control plan test data is the only stack test data available.

Proposed changes to §117.211, concerning Initial Demonstration of Compliance and to §117.213, concerning Continuous Demonstration of Compliance, update the sections to reflect the proposed new names of the division and a cross referenced section.

The proposed change to §117.213(a)(2) would provide an alternative certification procedure for stack exhaust flow meters installed as an alternative to fuel flow meters. The proposed alternative procedure is in 40 CFR 60, which is more appropriate to the ICI source monitoring requirements, which are based on 40 CFR 60 procedures rather than the 40 CFR 75 acid rain procedures. The proposed new §117.213(c)(1)(C) would require units which are tied into a common stack to be monitored with a NO_x

CEMS or PEMS, if the heat input from all the units combined exceeds 250 MMBtu/hr. The proposed requirement would provide additional NO_x monitoring that would be equally effective as the monitoring currently required for boilers individually rated more than 250 MMBtu/hr. The proposed change to §117.213(e)(1)(C) clarifies that the ongoing quality assurance procedures applicable to NO_x CEMS are also applicable to the diluent monitor used with the CEMS. The proposed change to §117.213(e)(2) clarifies that the diluent monitor isn't necessary if an exhaust flow monitor is used. The proposed change to §117.113(j) broadens the cross reference to emission specifications to the entire rule division to ensure that loss of exemption requirements also apply to the §117.106 limits.

The proposed changes to §117.215, concerning Final Control Plan Procedures, update the section to reflect the proposed new names of the rule division and cross referenced sections.

The proposed new §117.216, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, specifies certain information for showing compliance with the attainment demonstration emission specifications of §117.206, to be included in a report submitted to the executive director. The proposed requirements are parallel to existing requirements in §117.215.

The proposed changes to §117.217, concerning Revision of Final Control Plan, and §117.219, concerning Notification, Recordkeeping and Reporting Requirements, update the sections to reflect the proposed new names of cross referenced sections. An additional proposed change to §117.217 would divide the section into subsections to make the text less dense and more readable.

Proposed changes to §117.221, concerning Alternative Case Specific Specifications, update the section to reflect the proposed new names of the rule division and cross referenced sections. An additional proposed change to §117.221 adds reference to the CO and ammonia limits of §117.206(d), which would allow alternative emission specifications to be established on a case specific basis for these pollutants.

The proposed changes to §117.223(a) and (k), concerning Source Cap, update the subsections to reflect the proposed new names of cross referenced sections and add a cross reference in §117.223(a) to the proposed new emission specifications of §117.206 to allow the source cap to be used as an alternative means of compliance for these limits. The proposed changes to §117.223(b) revise the definitions of the terms used to calculate the source cap, separating existing requirements for source cap compliance with NO_x RACT and proposed requirements for source cap compliance with the attainment demonstration emission specifications. For compliance with the attainment demonstration limits, the baseline period for H_i, the historical heat input, is updated to 1997-1999 because individual unit heat input records from the NO_x RACT baseline of 1990-1993 have become old enough to be difficult to obtain. The allowable emission rate term, R_i, is updated to include the attainment demonstration emission specifications and for potentially applicable permit limits, modify the dates to be consistent with the attainment demonstration modeling for BPA and DFW. The proposed changes to §117.223(g) would make the subsection applicable only to early shut down credits used for NO_x RACT compliance. Paragraph §117.223(g)(6), which was added in the previous rule making (Phase I) for lean-burn engines in BPA, is proposed to be moved to new §117.223(h), which addresses the use of reduction credits from shut down units for compliance with both the lean-burn engine emission specification of §117.205(e) and the proposed attainment demonstration emission specifications of §117.206. To accommodate new §117.223(h), existing §117.223(h) - (j) would be relettered §117.223(i) - (k). Existing §117.223(k), added in the previous rule making for lean-burn engines in BPA, is proposed to be deleted since the requirements are included in the proposed revised §117.223(b).

A proposed change to Subchapter D, relating to Administrative Provisions, reletters the title to Subchapter E. The relettering reserves Subchapter D for rules for small combustion sources, proposed concurrently in a separate section of this issue of the *Texas Register*.

A proposed change to §117.510, concerning Compliance Schedule for Utility Electric Generation, would rename the section title to "Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas," to distinguish this section from the proposed section applicable to utility electric generation in a regional area, proposed in a separate location of this issue of the *Texas Register*. The proposed changes to §117.510(a) for sources in BPA, and §117.510(b) for sources in DFW, would create separate paragraphs in each subsection addressing compliance schedules for the NO_x RACT rules and the proposed emission specifications for attainment demonstrations. In addition, the NO_x RACT compliance schedule for sources in HGA is proposed to be moved to a separate new subsection, §117.510(c).

The commission is proposing a staged schedule for compliance with the proposed new BPA and DFW emission specifications for electric utility boilers, consistent with the proposed compliance schedule for ICI boilers and heaters in BPA. This would make the proposed schedule consistent for all sources in BPA affected by the proposed new emission limits. For the electric utility boilers in DFW, the proposed five-year implementation schedule sets a future three-step phase-in of the reductions. First, the existing

0.20 lb NO_x/MMBtu NO_x RACT limit of §117.105 requires a reduction of about 30% from the current DFW utility average of 0.28 lb NO_x/MMBtu, by March 31, 2002. Next, two-thirds of the total reductions required to comply with the 0.033 lb NO_x/MMBtu attainment demonstration emission specification (creating an average of about 0.11 lb NO_x/MMBtu) would be required by May 1, 2003. The final one-third of the reductions would be required by May 1, 2005. Although there are fewer utility units in DFW affected by the proposed emission specifications than ICI units in BPA, the DFW utility sources will be required to make much larger reductions, necessitating a combination of combustion and flue gas cleanup controls on most units.

A proposed change to §117.520, concerning Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources, would rename the section title to "Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas," to distinguish this section from the proposed section applicable to ICI sources in a regional area, proposed in a separate location of this issue of the *Texas Register*. The proposed changes to §117.520(a) for sources in BPA, and §117.520(b) for sources in DFW, would create separate paragraphs in each subsection addressing compliance schedules for the NO_x RACT rules and the proposed emission specifications for attainment demonstrations. The commission is proposing a staged compliance schedule for the proposed new BPA emission specifications for boilers and heaters. The time frame allows implementation of the necessary control measures over five years. Because of the number of units required to reduce emissions under the new standards, shorter time frames could affect the availability of engineering resources and the manufacturing capability of control equipment manufacturers. The commission is proposing a compliance date of March 31, 2002 for the ICI sources in DFW, which would allow two years for implementation of the control measures in DFW. In contrast to the proposed emission limits in BPA, the proposed new ICI emission limits in DFW will probably affect eight to ten pieces of equipment at three or four major stationary NO_x sources. Also, unlike many of the heaters and boilers used in the petrochemical and oil refining industries in BPA, this equipment is not operated in near-continuous duty with strictly limited turnarounds. Scheduling outages for the control equipment installation in DFW should be relatively straightforward.

Proposed changes to §117.570, concerning Trading, update the section to reflect the proposed new names of cross referenced sections and add cross references to the proposed new emission specifications of §117.106 and §117.206 to allow the source cap to be used as an alternative means of compliance for these limits. The proposed changes to §117.570(b) revise the definitions of the terms used to calculate the reduction credits. In §117.570(b)(1)(A), the emissions baseline for trading for compliance with NO_x RACT and the emissions baseline for trading for compliance with the attainment demonstration emission specifications are distinguished. For compliance with the attainment demonstration limits, the baseline period must occur after the date of the attainment demonstration modeling inventory in order for reductions to be surplus to the attainment demonstration. Similarly, in §117.570(b)(2), the heat input term, H_j, used to calculate a reduction credit, is revised by cross referencing to the proposed revised definitions used in §117.223. Also in §117.570(b)(2), the allowable emission rate term, R_{Aj}, is revised by separating existing requirements for NO_x RACT trading and proposed new requirements for trading for compliance with the attainment demonstration emission specifications. The proposed new requirements include calculating surplus against the attainment demonstration emission specifications, and for potentially applicable permit limits, permit effective dates consistent with the attainment demonstration modeling for BPA and DFW. In §117.570(b)(2), similar revisions are proposed to the allowable emission rate term, R_{Ai}, separating existing requirements for NO_x RACT trading and new requirements for trading for compliance with the attainment demonstration emission specifications. Existing §117.570(f), added in the previous rule making for lean-burn engines in BPA, is proposed to be deleted since the requirements are included in the proposed revised §117.570(b).

The commission proposes repeal of §117.601, concerning Gas-Fired Steam Generation, because the §117.601 requirements are proposed to be relocated to new §117.104, under the rule division for utility electric generation in ozone nonattainment areas and to new §117.134, under a new division for electric utility generation in east and central Texas, proposed in a separate section of this issue of the *Texas Register*.

FISCAL NOTE

Bob Orozco, Technical Specialist in the Strategic Planning and Appropriations Section, has determined that for the first five-year period the proposed amendments to Chapter 117, Control Of Air Pollution From Nitrogen Compounds, are in effect there will be no significant fiscal implications for units of state government and most units of local government as a result of administration or enforcement of the proposed amendments. However, there will be significant fiscal implications for the cities of Denton and Garland in the DFW area because they will be required to install emission controls, reduce operations, or otherwise obtain emission reductions for city-owned electric utility boilers.

The proposed amendments to Chapter 117 establish new emission limits for the BPA and DFW ozone attainment demonstrations. Many of the amendments are designed to allow the use of existing NO_x RACT rule mechanisms with the proposed emission limits. Although both NO_x RACT requirements and the proposed attainment demonstration requirements exist, the proposed attainment demonstration limits will control for most of the sources affected by the proposed amendments because they are more stringent than the limits for NO_x RACT. The proposed amendments would require certain electric utility and industrial, commercial, and institutional boilers in the BPA and DFW ozone nonattainment areas to meet new emission specifications and other requirements in order to reduce emissions of NO_x and ozone air pollution. The proposed amendments would also require certain process heaters in the BPA area and lean-burn engines in the DFW area to meet new emission specifications and other requirements in order to reduce NO_x emissions and ozone air pollution. These standards and specifications are part of the strategy to reduce emissions of NO_x necessary for the counties in the BPA and DFW ozone nonattainment areas to be able to demonstrate attainment with the NAAQS for ozone. The proposed amendments are one element of the proposed DFW and BPA attainment demonstration SIP. A SIP is a plan developed for any region where existing (measured and estimated) ambient levels of pollutant exceeds the levels specified in a national standard. The plan sets forth a control strategy that provides emission reductions necessary for attainment and maintenance of the national standards.

Analysis of the 1996 emission inventory database indicates that the proposed amendments could affect 36 utility boilers located at 11 major sources, 7 ICI boilers located at three major sources, and 3 lean-burn engines located at two major sources in the DFW area. The inventory also indicates that 5 utility boilers, 32 industrial boilers, and 59 process heaters located at 19 major sources in the BPA area would be affected by the proposed amendments.

The proposed emission limit for utility boilers and gas-fired industrial boilers in the BPA area with maximum rated capacity of 40 MMBtu/hr or greater is 0.10 lb NO_x/MMBtu. It is anticipated that emission reductions will be achievable with either combustion modification techniques for tangential-fired boilers or low-NOx burners for wall-fired boilers. The proposed emission limit for process heaters in the BPA area with a maximum rated capacity of 40 MMBtu/hr or greater is 0.08 lb NO_x/MMBtu.

The proposed emission limit for utility boilers in the DFW area with maximum rated capacity of 40 MMBtu/hr or greater is 0.033 lb NO_x/MMBtu. The proposed 88% emission reduction, calculated from the average emissions of the utility boilers in the area during the baseline period, is expected to necessitate SCR on the affected DFW utility boilers. The proposed emission limit for gas-fired industrial, commercial, and institutional boilers in the DFW area with maximum rated capacity of 40 MMBtu or greater is 30 parts per million by volume (ppmv) NO_x at 3% oxygen, dry basis. The proposed emission limit for gas-fired or gas/liquid-fired, lean-burn, stationary reciprocating combustion engines rated 300 horsepower or greater is 2.0 g NOx/hp-hr and 3.0 g CO/hp-hr.

System-wide emission averaging for electric utilities will not be allowed in the proposed amendments because this averaging may not produce the intended reductions. Units which require extensive controls often have higher operating costs than units with less emission control equipment. If units selected for less control are subsequently operated more, or if units selected for more control are subsequently operated less in order to minimize operating costs, the designed emission reductions may not be achieved. Instead, a system cap is proposed with the new NO_x limits which avoids the issue of equivalent emissions reductions that is associated with emission averaging. The proposed System Cap would create a flexible new alternative patterned on the existing source cap compliance option for ICI combustion sources. The System Cap sets limits on total pounds of NO_x allowed to be emitted by an electric utility system. The cap will have the advantage of allowing the source owner to control the activity levels of the regulated equipment as a means of compliance. This may include installing less extensive emission controls on a piece of equipment and choosing to operate it less and/or upgrading its efficiency to require less fuel firing. The affected electric utility boilers in DFW and BPA are currently monitoring NO_x emissions continuously under the federal acid rain rules. The absence of additional cost for new NO_x monitors is expected to make the system cap an attractive option for electric utilities.

The proposed amendments contain a schedule for compliance with the new BPA and DFW emission specifications for electric utility boilers, consistent with the proposed compliance schedule for industrial, commercial, and institutional boilers and heaters in BPA. For electric utility boilers in DFW, the proposed five-year implementation schedule sets a future three-step phase-in of the reductions. The existing 0.20 lb NO_x/MMBtu RACT limit requires a reduction of about 30% from the current DFW utility average of 0.28 lb NO_x/MMBtu by March 31, 2001. Next, two-thirds of the total reductions required to comply with the 0.033 lb NO_x/MMBtu attainment demonstration emission specification would be required by May 1, 2003. The final one-third of the reduction would be required by May 1, 2005. Although there are fewer utility units in DFW affected by the proposed emission specifications than ICI units in BPA, the DFW utility sources will be required to make much deeper reductions, probably necessitating a combination of combustion and flue gas cleanup controls on most units.

PUBLIC BENEFIT

Mr. Orozco has also determined that for each year of the first five years the proposed amendments to Chapter 117 are in effect, the public benefit anticipated from enforcement of and compliance with the proposed amendments will be: a reduction of public exposure to NO_x emitted from affected utility boilers, ICI boilers, lean-burn engines, and process heaters; the concomitant reduced risks to human health and safety from ozone; a reduction of ground-level ozone in ozone nonattainment areas; and conformance with the requirements of the FCAA.

The proposed amendments to Chapter 117 apply to certain electric utility boilers, ICI boilers, and lean-burn engines in DFW and to certain electric utility boilers, ICI boilers, and process heaters in BPA. The proposed amendments would require certain electric utility and ICI boilers in BPA and DFW to meet new emission specifications and other requirements in order to reduce emissions of NO_x and ozone air pollution. The proposed amendments would also require certain process heaters in the BPA area and lean-burn engines in the DFW area to meet new emission specifications and other requirements in order to reduce NO_x emissions and ozone air pollution. These standards and specifications are part of the strategy to reduce emissions of NO_x necessary for the counties in the BPA and DFW ozone nonattainment areas to be able to demonstrate attainment with the NAAQS for ozone.

The proposed emission limit for utility boilers and gas-fired ICI boilers in the BPA area with maximum rated capacity of 40 MMBtu/hr or greater is 0.10 lb NO_x/MMBtu. It is anticipated that emission reductions will be achievable with combustion modification techniques. The proposed emission limit for process heaters in the BPA area with a maximum rated capacity of 40 MMBtu/hr is 0.08 lb NO_x/MMBtu.

The proposed emission limit for utility boilers in the DFW area with maximum rated capacity of 40 MMBTU/hr or greater is 0.033 lb NO_x/MMBtu. The proposed 88% emission reduction, calculated from the average emissions of the utility boilers in the area during the baseline period, is expected to necessitate SCR on the affected utility boilers in the DFW area. The proposed emission limit for gas-fired ICI boilers in the DFW area with maximum rated capacity of 40 MMBtu/hr or greater is 30 ppmv NO_x at 3% oxygen, dry basis. The proposed emission limit for gas-fired or gas/liquid-fired, lean-burn, stationary reciprocating combustion engines rated 300 horsepower or greater is 2.0 g NO_x/hp-hr and 3.0 g CO/hp-hr.

In both the DFW and BPA areas, the proposed emission limit for carbon monoxide is 400 ppmv at 3% oxygen, dry basis based on a one-hour average for units not equipped with CEMS or PEMS for CO or a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO. The proposed emission limit for ammonia is 5 ppmv based on a block one-hour averaging period.

A staff analysis of the agency's 1996 emissions inventory data indicated that there are 12 companies/entities in the DFW area which operate 18 sites which are major sources of NO_x. The information obtained from the inventory and from telephone inquiries also indicated 43 boilers owned or operated by 6 of the 12 entities could be affected by the rule's emission limitations in the DFW area. Of these, 36 are utility power boilers, and 7 are ICI boilers.

The proposed limit of 0.033 lb NO_x/MMBtu for electric utility boilers in DFW represents an 88% reduction from the July - September, 1996 - 1998 average emission rate, calculated from hourly emissions and heat input data from the EPA acid rain data base. The electric utility boilers in DFW are currently subject to a Chapter 117 RACT limit of 0.20 lb NO_x/MMBtu, 30-day rolling average, with a compliance date of March 31, 2001. The cost of the anticipated combustion modifications necessary to comply with this limit was estimated in the NO_x RACT rulemaking effective March 21, 1999 (see proposal at 23 *TexReg* 11281). This cost note will assume that SCR will be necessary to achieve the proposed 0.033 lb NO_x/MMBtu limit, which represents an 83.5% reduction from NO_x RACT. The literature contains a wide range of cost estimates for SCR applied to electric utility boilers. Earlier documents, such as the 1994 EPA ACT for utility boilers, estimated SCR capital costs for gas-fired boilers in a range of $42/kW-$74/kW, depending on boiler size and capacity factor. More recent studies, such as "*Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers*," NESCAUM/MARAMA (June 1998), estimated the costs for gas-fired boilers in the range of $25/kW-$35kW. The EPA ACT relies more on extrapolations from limited data, whereas the NESCAUM/MARAMA report is based on a case study of more recent experience in installing SCR on gas-fired utility boilers in southern California. In this cost note, the costs of applying SCR are estimated from the NESCAUM report. The report estimates the SCR capital costs for gas-fired utility boilers at $30/kW. The EPA cost model limits gas-fired SCR reductions to 80%, which is a conservative assumption. The SCR NO_x reduction averages closer to 90% for the California gas-fired units shown on Table 2-5 of the NESCAUM report, and is as high as 94% for the units with higher baselines, near the DFW NO_x RACT baseline of 0.20 lb NO_x/MMBtu.

Model inputs included the Chapter 117 NO_x RACT limit of 0.20 lb NO_x/MMBtu for the emission baseline, and each unit's average capacity factor for 1996 through 1998, calculated from maximum design heat input data contained in the emission inventory and actual heat input data in the EPA acid rain data base. Assuming a uniform baseline equal to the NO_x RACT limit is an approximation. Some of the boilers are currently operating below 0.20 lb NO_x/MMBtu, and after compliance with NO_x RACT, some of the boilers will operate above this rate under emission averaging. Because of this flexibility, the exact combination of combustion modification controls to achieve the NO_x RACT baseline is not determinable. However, each utility will be required to reduce emissions in DFW to comply with NO_x RACT, so the NO_x RACT baseline gives an accurate estimate of the overall amount of additional reductions required by the proposed attainment demonstration emission limits.

The proposed amendments do not specify a particular control technology to achieve the emission limits and there may be other control technologies or combinations of control technologies which may be used to comply. In addition, the proposed amendments contain compliance flexibility, including a system cap, which is a flexible performance target, and emissions trading, which allows compliance to be established through the use of surplus reductions created from other sources.

Two cities in DFW operate three municipal electric utility plants with a total of 13 gas-fired power boilers. The city of Denton operates a single plant with a total of five boilers. At this plant, in the last three years (1996-1998), Units 1 and 2 were operated with annual heat input well under the $2.2(10)^{11}$ Btu/year exemption level in Chapter 117 for low annual heat input boilers rated more than 100 MMBtu/hr and would appear to be exemptible from the requirements of Chapter 117. Unit 3 was also operated well below the low annual heat input exemption level in 1996 and 1997, but over the exemption level in 1998. In a future year similar to 1998, restricting Unit 3 operation to the annual exemption level is expected to have minimal impact on system generating capability because in 1998, if Unit 3 had been restricted to the annual heat input exemption, Units 1 and 2 could have made up the difference without exceeding the exemption level. Units 4 and 5 have been operated historically at levels above the Chapter 117 low annual capacity exemption. The cost of applying SCR on Units 4 and 5 to comply with the proposed emission limit is estimated as follows. For Unit 4, a 61 MW wall-fired unit, the 1996-1998 average annual capacity factor was 21%. For Unit 5, a 68 MW wall-fired unit, the 1996-1998 average annual capacity factor was 31%. The estimated cost of compliance with the proposed limit is $3,125/ton of NO_x reduced for Unit 4 and $2,226/ton of NO_x reduced for Unit 5. The average annualized weighted cost for all affected units in Denton is $2,568 per ton of NO_x reduced. It is estimated that these two boilers will be required to reduce NO_x emissions by 327 tons. The total annual fiscal impact for the city of Denton is approximately $839,736.

The city of Garland in the DFW area operates two power plants with a total of eight gas-fired power generating boilers. At the plant with five boilers, in the last three years (1996-1998), Units 1 through 4 were operated with annual heat input well under the $2.2(10)^{11}$ Btu/year exemption level in Chapter 117 for low annual heat input boilers and would appear to be exemptible from the requirements of Chapter 117. Unit 5, a 42 MW wall-fired unit, was operated with an annual capacity factor of 10% between 1996-1998. The estimated cost of compliance with the proposed limit is approximately $2743/ton of NO_x reduced for Unit 5. At the plant with three boilers, the estimated cost of SCR to comply with the proposed limit is approximately $2237/ton of NO_x reduced for Unit 1, a 76 MW tangential-fired boiler operated at a 30% capacity factor between 1996 and 1998; approximately $1780/ton for Unit 2, a 109 MW wall-fired boiler operated on average 41%, 1996-1998; and approximately $1531/ton for Unit 3, a 153 MW wall-fired unit operated on average 48%, 1996-1998. The average annualized weighted cost for all affected units in Garland is $1,762 per ton of NO_x reduced. It is estimated that these boilers will be required to reduce NO_x emissions by 1,307 tons. The total annual fiscal impact for the city of Denton is approximately $2,302,934.

One investor-owned electric utility operates eight power plants with a total of 23 gas-fired electric utility power boilers in the area. For purposes of developing this note, it will be assumed that SCR will be applied to each of 23 boilers to comply with the proposed NO_x emission limit. Based on the NESCAUM report, annual cost for a 550 MW unit is approximately $1694/ton of NO_x reduced and for a 33 MW unit, $6,529/ton. The average annualized weighted cost for all affected units in this utility is $2,721 per ton of NO_x reduced.

An analysis of all the utility boilers in the DFW area was accomplished by the commission staff to determine the annualized average weighted cost for emission reductions in dollars per ton of NO_x reduced. It is estimated that DFW utility boilers will be required to reduce NO_x emissions by approximately 11,694 tons at an annual weighted cost of approximately $2,610 per ton of NO_x reduced. The annual DFW utility boiler fiscal impact is approximately $30.5 million.

Three industrial sources in the DFW area were identified that operate seven boilers that would be subject to lower emission limits under the proposed amendments. Two boilers are at the University of Texas Southwest Medical Center, three at DFW International Airport, and two at the Miller Brewing Company. If there are any additional boilers required to reduce emissions, not identified by the emissions data analysis, it is anticipated that their compliance costs would be similar to the analysis which follows. Available information indicates that these boilers do not operate with air preheat. FGR is anticipated to be capable of providing the emission reductions necessitated by the proposed limit. The cost was estimated using the EPA Alternative Control Techniques (ACT) document, "NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers," EPA-453/R-94-022. Estimated capital costs are $2,070/MMBtu/hr of rated heat input for a 150 MMBtu/hr field-erected watertube boiler, and $4,460/MMBtu/hr for a 50 MMBtu/hr packaged watertube boiler. The annual operating cost is estimated at a range between $1390-$1670/ton of NO_x reduced per year. It is estimated that these boilers will be required to reduce NO_x emissions by 153 tons. The total annual fiscal impact for ICI boilers in the DFW area is approximately $212,659 to $255,496.

The 1996 emissions inventory analysis and telephone inquiries revealed the information that two companies had boilers that would have been subject to the rule in 1996, but have since replaced them, or are in the process of replacing them. These new boilers will not be subject to the Chapter 117 rule, since the proposed rule does not apply to units installed after November 15, 1992, unless they are functionally identical replacements intended to provide emission reduction credits for other units.

The 1996 emissions inventory analysis also indicated four boilers rated between 40 and 100 MMBtu/hr, located at two major sources, were operated with annual heat input well under the $2.8(10)^{11}$ Btu/year exemption level in Chapter 117 for low annual heat input boilers in this size range. Because these sources operated at less than half the exemption level, this cost note will assume that compliance with the exemption will not result in additional cost. The current NO_x RACT rule requires these boilers to install fuel use meters, which would be used to monitor compliance with the emission limit exemption. However, should the boilers need to be operated in the future above the exemption level, the cost of compliance would be similar to the boilers requiring controls.

The 1996 emissions inventory indicated that the proposed emission limit of 2.0 g NO_x/hp-hr for lean-burn, gas-fired and gas/liquid-fired engines would affect 3 engines located at two major sources in DFW. If there are any additional lean-burn engines required to reduce emissions, not identified by the emissions data analysis, it is anticipated that their compliance costs would be similar to the analysis which follows. The types of modification that could be applied to meet the proposed limit include low emission combustion (LEC) retrofit, SCR, and replacement with electric motors. For purposes of this fiscal note, it will be assumed that LEC will be used, since it is the least expensive of these options and the affected engine models are capable of being retrofit with LEC to meet the emission limits. The cost estimation methodology used by EPA in their ACT document, "NO_x Emissions from Stationary

Reciprocating Internal Combustion Engines," EPA-453/R-93-032, July 1993, was used with capital equipment estimates for the specific models affected.

One of the sources, a gas compressor station with two, 1100 hp White-Superior 8GT825 engines is not currently operating. The two engines could maintain exempt status under the §117.203(6)(B) exemption for engines operated less than 850 hours per year. However, the cost of compliance is estimated in the following analysis, under the assumption that the engines will need to be operated above the exemption level in the future. The other source is a medical complex with a 6434 hp Cooper-Bessemer LSVB-16-GDT dual fuel (natural gas ignited by compression of diesel fuel) engine used to cogenerate electricity and steam.

Current emissions are estimated at 15 g NO_x/hp-hr (4.4 lb NO_x/MMBtu) for the two 8GT825 engines and 5 g NO_x/hp-hr (1.8 lb NO_x/MMBtu) for the dual fuel engine, based on the manufacturer's estimates. Therefore, the required NO_x reduction to comply with the proposed emission limit is 87% for the 8GT825 engines, and 60% for the dual fuel engine.

The retrofit kit to convert an 8GT825 engine to meet a 2.0 g NO_x/hp-hr limit was priced at $67,000 by the manufacturer in 1992. The retrofit kit to convert the dual-fuel engine to meet a 2.0 g NO_x/hp-hr limit was priced between $700,000 and $870,000 by the manufacturer in 1992. According to the manufacturer, the 1992 prices are still a reasonable estimate in 1999. The total capital cost, reflecting tax, freight, direct installation cost, indirect installation cost and contingency, is estimated by applying the ACT factor, equal to 1.73 times hardware cost. The total LEC retrofit capital cost is $116,000 for each 8GT825 engines and $1,358,000 for the dual fuel engine, using the average of the manufacturer's range. The ACT identifies additional spark plug and precombustion chamber fuel check valve replacement as LEC retrofit items which result in increased maintenance cost, but applies a factored cost to estimate annual additional maintenance cost. The maintenance cost factor is 10% of the total capital cost. According to the OEMs, LEC reduces engine misfire, which is beneficial to valve liner and piston ring life, and also reduces engine oil and jacket water operating temperatures. Maintenance cost reductions resulting from these improvements are not easily quantified, and are not specifically included in the maintenance cost estimate. The ACT operating cost factor for taxes, insurance, and administrative costs is adjusted by removing the property tax component, to account for Proposition 2, a state property tax exemption for capital investments made to comply with environmental law. The ACT's overhead cost factor, equal to 60% of maintenance cost, a fuel penalty of $14,155 was used for the large engine and a fuel credit of $2670 was used for the smaller engines, and a 15-year, 7% capital recovery factor of 0.1098 are used. The ACT's test costs are adjusted to more specifically reflect the proposed test requirements, which would extend the test requirements for rich-burn engines to the lean-burn engines. In order to ensure initial and continued emissions compliance, any owner or operator of engines subject to the emission limits would be required to perform a compliance test before the initial compliance date, and every two years following. The compliance test costs are estimated at $2,500 per engine for the first engine, and $750 for an additional engine at a site. The rule also requires emission checks at least quarterly with stain tubes or portable analyzers. The emission check cost is estimated at $400 per engine. The total emission test costs are estimated at $2,650 annually per engine. The rule requires record keeping of maintenance performed on the emission control equipment. The additional record keeping costs are estimated as negligible, since the rule does not specify explicit contents, and maintenance records are already being kept for these engines. Using the Alternative Control Techniques computer model to estimate annual costs, it was estimated that the annualized cost to reduce emissions was approximately $33,403 per year for each of the 800 horsepower engines and $317,531 per year for the larger 6,434 horsepower engine. The total annual fiscal impact for lean-burn engines in the DFW area is approximately $384,338.

Analysis of the 1996 emission inventory database indicates that the proposed amendments would affect 5 utility boilers, 32 industrial boilers, and 59 industrial process heaters in the BPA area.

There are five operating electric utility boilers located at the Entergy Sabine power plant in BPA. Four of the five natural gas-fired boilers are tangential-fired and one is wall-fired. Annual average emissions reported in the 1997 EPA acid rain data base were 0.16 lb NO_x/MMBtu from the four tangential boilers and 0.25 lb NO_x/MMBtu from the wall-fired unit. The five boilers currently are required to meet the NO_x RACT limit, 0.20 lb NO_x/MMBtu, 30-day average, and are using emission averaging to comply. The proposed emission limit, 0.10 lb NO_x/MMBtu, would also apply on a system-wide 30-day rolling average; therefore the proposed rules represent approximately a 50% NO_x emission reduction from the utility power boilers in BPA.

This cost note will assume that the 0.10 lb NO_x/MMBtu limit will be achieved through the use of combustion modifications. Combustion modifications, including separate over-fired air (OFA) and FGR, achieved 1997 emissions of 0.05 lb NO_x/MMBtu, annual average and 0.09 lb NO_x/MMBtu short term maximum on the Pittsburg 7 unit near Pittsburg, California. Pittsburg 7 is a 750 MW, tangential, gas-fired utility boiler. According to the boiler manufacturer, the installed equipment cost for combustion controls of this type range from $2 to $12 per kW of installed capacity.

The Pittsburg 7 results suggest that the necessary control level for the wall-fired Unit 4 could be reduced under system-wide emission compliance if the controls applied to the four tangential-fired boilers achieved performance similar to Pittsburg 7. For example, an emission rate of 0.07 lb NO_x/MMBtu on a rolling 30-day average, which splits the difference between the short term maximum and the annual emission rate at Pittsburg 7, could allow Unit 4 to operate at approximately 0.17 lb NO_x/MMBtu on a rolling 30-day average.

In addition, four of the five utility boilers are grandfathered units subject to Senate Bill (SB) 7, which requires reductions based on 1997 activity levels and a limit of 0.14 lb NO_x/MMBtu. These requirements represent about a 32% reduction from the four boilers, and 28% reduction when expressed as the total emissions from all five boilers. Because SB 7 does not mandate that the emission reductions be obtained in BPA, and because control costs are not proportional to reductions, it is not possible to estimate the proportion of the costs that are already mandated by SB 7.

An analysis of the utility boilers in the BPA area was accomplished by the commission staff to determine the annualized average weighted cost for emission reductions in dollars per ton of NO_x reduced. It is estimated that BPA utility boilers will be required to reduce NO_x emissions by approximately 3,595 tons at an annual cost ranging from $520 to $1,500 per ton of NO_x reduced, depending on the size of the boiler. The annual BPA utility boiler fiscal impact is approximately $2.9 million.

The agency's 1997 emission inventory data indicates there are four petroleum refineries and seventeen chemical plants which are major sources of NO_x in the BPA area. Only fourteen of the major source chemical plants operate boilers or heaters. Based on the inventory and supplemental information obtained from the plants in September, 1999, the proposed rule would lower the applicable emission limits for approximately 32 of the 84 boilers and 59 of the 169 process heaters rated above 40 MMBtu/hr at the plants. The proposed rule would not lower the effective emission limit for: 14 boilers currently operating at or below the proposed emission limit; 14 exempt Boiler Industrial Furnaces (BIF); 10 boilers at a refinery issued a flexible air quality permit requiring 0.08 lb NO_x/MMBtu; 11 boilers which have been or are planned to be shutdown before the proposed compliance date; and 4 boilers exempt under the low annual capacity factor exemption.

The affected boilers and heaters are all gas-fired units, for which combustion modifications are effective at reducing NO_x emissions. This cost note will assume that the boilers will use low-NO_x burners or FGR (or both) and the heaters will use low-NO_x burners to comply with the proposed emission limits. However, the rule does not specify a particular control technology to achieve the emission limits and there may be other control technologies, such as over fired air for larger boilers, or combinations of control technologies, which may be used to comply. In addition, the rule allows emission averaging, source cap, and emissions trading compliance flexibility which mitigates the control costs for specific units which may otherwise face uniquely high control cost to achieve compliance.

It is anticipated that 32 industrial boilers in the BPA area will be affected by the proposed amendments. It is estimated that these boilers will be required to reduce NO_x emissions by 2,778 tons per year. It is estimated that the cost will be a range of approximately $1,390 to $1,670 per ton of NO_x reduced per year. The total annual fiscal impact for industrial boilers in the BPA area is approximately $3.8 million to $4.6 million per year.

It is anticipated that 59 industrial process heaters in the BPA area will be affected by the proposed amendments. It is estimated that these heaters will be required to reduce NO_x emissions by 1,476 tons. It is estimated that the cost will be a range of approximately $1,100 to $2,160 per ton of NO_x reduced per year. The total annual fiscal impact for industrial process heaters in the BPA area is approximately $1.6 million to $3.2 million per year.

The total cost per year for all known affected sources in the DFW and BPA areas is approximately $39.5 million to $42.0 million.

SMALL BUSINESS AND MICRO-BUSINESS ANALYSES

The agency has been unable to identify any small businesses or micro-businesses as defined in the Texas Government Code which would be affected by these proposed amendments to Chapter 117. If there are affected small businesses or micro-businesses, the estimated annualized cost for installing and operating the control technology in dollars per ton of NO_x reduced that was used for the various types of units in this fiscal note would appear to be a reasonable cost estimate for small businesses or micro-businesses. The proposed amendments do not specify a particular control technology to achieve the emission limits and there may be other control technologies or combinations of control technologies which may be used to comply. In addition, the proposed amendments contain compliance flexibility, including a system cap, which is a flexible performance target, and emissions trading, which allows compliance to be established through the use of surplus reductions created from other sources.

DRAFT REGULATORY IMPACT ANALYSIS

The commission has reviewed the proposed rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking meets the definition of a "major environmental rule" as defined in that statute "Major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. The amendments to Chapter 117 will require emission reductions from electric utility, industrial, commercial and institutional boilers in the DFW and BPA ozone nonattainment areas. The rules are intended to protect the environment and reduce risks to human health and safety from environmental exposure and may have adverse effects on certain utilities in both DFW and BPA ozone nonattainment areas and certain petrochemical plants and refineries in BPA, and each group could be considered a sector of the economy. The proposed amendments do not meet any of the four applicability criteria of a "major environmental rule." Section 2001.0225 applies only to a major environmental rule the result of which is to:

(1) exceed a standard set by federal law, unless the rule is specifically required by state law;

(2) exceed an express requirement of state law, unless the rule is specifically required by federal law;

(3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program or;

(4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

The amendments implement requirements of the FCAA. FCAA, §110 requires states to submit SIPs which contain enforceable measures to achieve the NAAQS. The proposed rules, which reduce ambient NO_x and ozone in BPA, will be submitted to EPA—upon adoption—as one of several measures of the required new attainment demonstrations. These rules will also implement NO_x RACT for smaller boilers and heaters at major sources in BPA and DFW and lean-burn engines at major sources in DFW. FCAA, §182(f) requires any moderate, serious, severe, or extreme ozone nonattainment area to implement NO_x RACT. The proposed amendments are necessary components of and consistent with the ozone attainment demonstration SIPs for BPA and DFW, required by FCAA, §110. There is no contract or delegation agreement that covers the topic that is the subject of this rulemaking. Therefore, these proposed amendments do not exceed a standard set by federal law, exceed an express requirement of state law, nor exceed a requirement of a delegation agreement. In addition, the proposed changes are not proposed solely under the general rulemaking authority of the commission but are proposed to comply with the requirements of federal regulations.

The commission invites public comment on the draft regulatory impact analysis.

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 BPA and DFW. If adopted, certain major sources located in BPA and DFW will be required to install new emission control equipment, and implement new operating, reporting, and recordkeeping requirements. Installation of the necessary control equipment could conceivably place a burden on private, real property. 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. Although the rule revisions do not directly prevent a nuisance or prevent an immediate threat to life or property, they do prevent a real and substantial threat to public health and safety and significantly advance the health and safety purpose. In addition, these amendments to fulfill an obligation mandated by federal law. The proposed amendments will implement requirements of FCAA, §7410 and §7511a(f). This action is taken in response to the BPA and DFW areas exceeding the federal ambient air quality standard 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 BPA and 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.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

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 BPA and DFW, will result in reductions of ambient NO_x and ozone concentrations. The proposed rules are consistent with the applicable CMP policy because they are consistent with Title 40. Title 40, Part 51, sets out requirements for states to prepare, adopt, and submit implementation plans for the attainment of the NAAQS. The adopted rules would be submitted to EPA under these requirements. Interested persons may submit comments on the consistency of the proposed rules with the CMP during the public comment period.

PUBLIC HEARINGS

The commission will hold public hearings on this proposal at the following times and locations: January 24, 2000, 2:00 p.m., City of El Paso Council Chambers, 2 Civic Center Plaza, 2nd floor, El Paso; January 25, 2000, 10:00 a.m., Building E, Room 201S, Texas Natural Resource Conservation Commission Complex, 12100 Park 35 Circle, Austin; January 26, 2000, 10:00 a.m., Longview City Hall Council Chambers, 300 West Cotton Street, Longview; January 27, 2000, 7:00 p.m., City of Irvin Central Library Auditorium, 801 West Irvin Boulevard, Irvin; January 27, 2000, 10:00 a.m., Dallas Public Library Auditorium, 1515 Young Street, Dallas; January 27, 2000, 7:00 p.m., Lewisville City Council Chambers, Municipal Center, Lewisville; January 28, 2000, 10:00 a.m., Council Chambers, 2nd floor, Fort Worth City Hall, 1000 Throckmorton Street, Fort Worth; January 31, 2000, 1:30 p.m., John Grey Institute, 855 Florida Avenue, Beaumont; and January 31, 2000, 7:00 p.m., Houston-Galveston Area Council, 3555 Timmons Lane, Houston. The hearings are structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. Open discussion will not be permitted during the hearings; however, agency staff members will be available to discuss the proposal 30 minutes prior to the hearings and will answer questions before and after the hearings.

SUBMITTAL OF COMMENTS

Written comments may be mailed to Bettie Bell, MC 205, Office of Environmental Policy, Analysis, and Assessment, Texas Natural Resource Conservation Commission, P.O. Box 13087, Austin, Texas 78711-3087, or faxed to (512) 239-4808. All BPA comments should reference Rule Log Number 99056-117-AI. All DFW comments should reference Rule Log Number 99055d117-AI. Comments must be received by 5:00 p.m., February 1, 2000. For further information or questions concerning this proposal, please contact Randy Hamilton of the SIP Development Team at (512) 239-1512.

Persons with disabilities who have special communication or other accommodation needs who are planning to attend the hearings should contact the agency at (512) 239-4900. Requests should be made as far in advance as possible.

STATUTORY AUTHORITY

The amendments are proposed under Texas Health and Safety Code, TCAA, §382.011, which establishes the ability of the commission to control the quality of the state's air; §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.

The proposed amendments implement Texas Health and Safety Code, §382.012.

SUBCHAPTER B : COMBUSTION AT EXISTING MAJOR SOURCES

DIVISION 1 : UTILITY ELECTRIC GENERATION

IN OZONE NONATTAINMENT AREAS

§§117.101, 117.103-117.108, 117.111, 117.113, 117.115-117.117, 117.119, 117.121

§117.101. Applicability.

(a) The provisions of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas) shall apply to the following units used in an electric power generating system, as defined in §117.10(11)(A) of this title (relating to Definitions) owned or operated by a municipality or a Public Utility Commission of Texas (PUC) regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC, located within the Beaumont/Port Arthur, Houston/Galveston, or Dallas/Fort Worth ozone nonattainment areas:

(1) - (4) (No change.)

(b) (No change.)

§117.103. Exemptions.

(a) Units exempted from the provisions of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas), 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) - (3) (No change.)

(b) The fuel oil firing emission limitation of §117.105(c) or §117.107(b) of this title (relating to Emissions Specifications in Ozone Nonattainment Areas 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.

§117.104. 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 in the Dallas/Fort Worth ozone nonattainment area. This section shall no longer apply after the applicable final compliance date for reasonably available control technology specified in §117.510(b)(1) of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(b) No person shall allow emissions of nitrogen oxides (NO_x), calculated as nitrogen dioxide (NO_2), from any "opposed-fired" steam generating unit of more than 600,000 pounds per hour (lbs/hr) maximum continuous steam capacity to exceed 0.7 pound per million Btu (lb/MMBtu) heat input, maximum two-hour average, at maximum steam capacity. An "opposed-fired" steam generating unit is defined as a unit having burners installed on two opposite vertical firebox surfaces.

(c) No person shall allow emissions of NO_x, calculated as NO_2, from any "front-fired" steam generating unit of more than 600,000 lbs/hr maximum continuous steam capacity to exceed 0.5 lb/MMBtu heat input, maximum two-hour average, at maximum steam capacity. A "front-fired" steam generating unit is defined as a unit having all burners installed in a geometric array on one vertical firebox surface.

(d) No person shall allow emissions of NO_x, calculated as NO_2, from any "tangential-fired" steam generating unit of more than 600,000 lbs/hr maximum continuous steam capacity to exceed 0.25

lb/MMBtu heat input, maximum two-hour average, at maximum steam capacity. A "tangential-fired" steam generating unit is defined as a unit having burners installed on all corners of the unit at various elevations.

(e) Existing gas-fired steam generating units of more than 600,000 lbs/hour, but less than 1,100,000 lbs/hr, maximum continuous steam capacity are exempt from the provisions of this section, provided the total steam generated from the unit during any one calendar year does not exceed 30% of the product of the maximum continuous steam capacity of the unit times the number of hours in a year. Written records of the amount of steam generated for each day's operation shall be made on a daily basis and maintained for at least three years from the date of each entry. Such records shall be made available upon request to representatives of the executive director, Environmental Protection Agency (EPA), or any local air pollution control agency having jurisdiction.

§117.105. Emission Specifications for Reasonably Available Control Technology (RACT).

(a) - (g) (No change.)

(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 at 3.0% O_2, dry, based on

(1) a one-hour average for units not equipped with continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) for CO; [,] or

(2) [on] a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO.

(i) (No change.)

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

(k) (No change.)

§117.106. Emission Specifications for Attainment Demonstrations.

(a) Beaumont Port/Arthur. No person shall allow the discharge into the atmosphere from any utility boiler located in the Beaumont/Port Arthur ozone nonattainment area, emissions of nitrogen oxides (NO_x) in excess of 0.10 pound per million Btu heat input, on a rolling 24-hour average, except as provided in §117.108 of this title (relating to System Cap), or §117.570 of this title (relating to Trading).

(b) Dallas/Fort Worth. No person shall allow the discharge into the atmosphere from any utility boiler located in the Dallas/Fort Worth ozone nonattainment area, emissions of NO_x in excess of 0.033

pound per million Btu heat input, on a rolling 24-hour average, except as provided in §117.108 of this title or §117.570 of this title.

(c) Related emissions. No person shall allow the discharge into the atmosphere from any utility boiler subject to the NO_x emission limits specified in subsections (a) and (b) of this section:

(1) carbon monoxide (CO) emissions in excess of 400 parts per million by volume (ppmv) at 3.0% oxygen, dry, based on:

(A) a one-hour average for units not equipped with continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) for CO; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO; and

(2) ammonia emissions in excess of 5 ppmv, based on a block one-hour averaging period.

(d) Compliance flexibility.

(1) An owner or operator may use either of the following alternative methods of compliance with the NO_x emission specifications of this section:

(A) §117.108 of this title (relating to System Cap); or

(B) §117.570 (relating to Trading).

(2) An owner or operator may petition the executive director for an alternative to the CO or ammonia limits of this section in accordance with §117.121 of this title (relating to Alternative Case Specific Specifications).

(3) Section 117.107 of this title (relating to Alternative System-wide Emission Specifications) and §117.121 of this title are not alternative methods of compliance with the NO_x emission specifications of this section.

§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 for Reasonably Available Control Technology (RACT)) 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 as defined §117.10(11)(A) of this title 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 used for peaking service subject to the emission limits of §117.105(g) [§117.105(h) or (i)] of this title;

(B) (No change.)

(2) - (3) (No change.)

(b) - (d) (No change.)

§117.108. System Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations) by achieving equivalent NO_x emission reductions obtained by compliance with a system cap emission limitation in accordance with the requirements of this section.

(b) Each utility boiler within an electric power generating system, as defined in §117.10 (11)(A) of this title (relating to Definitions), that would otherwise be subject to the NO_x emission limits of §117.106 of this title must be included in the system cap.

(c) The system cap shall be calculated as follows.

(1) A rolling 30-day average emission cap shall be calculated using the following equation:

Figure: 30 TAC §117.108(c)(1)

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

Where:

I = each utility boiler in the electric power generating system

N = the total number of utility boilers in the emission cap

H_i = The average of the daily heat input for each utility boiler in the emission cap, in million Btu per day, as certified to the executive director, for the nine months of July, August, and September 1996, 1997, and 1998.

R_i = (A) For utility boilers in the Beaumont/Port Arthur ozone nonattainment area, the emission limit of §117.106(a) of this title; and

(B) For utility boilers in the Dallas/Fort Worth ozone nonattainment area, the emission limit of §117.106(b) of this title.

(2) A maximum daily cap shall be calculated using the following equation:

Figure: 30 TAC §117.108(c)(2)

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

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) Each utility boiler in the system cap shall be subject to the emission limits of both paragraphs (1) and (2) of this subsection at all times.

(d) The NO_x emissions monitoring required by §117.113 of this title (relating to Continuous Demonstration of Compliance) for each utility boiler in the system cap shall be used to demonstrate continuous compliance with the system cap.

(e) For each operating utility boiler, the owner or operator shall use one of the following methods to provide substitute emissions compliance data during periods when the NO_x monitor is off-line:

(1) if the NO_x monitor is a CEMS,

(A) Appendix E monitoring in accordance with §117.113(d) of this title;

(B) the maximum emission rate as measured by the testing conducted in accordance with §117.111(e) of this title; or

(C) PEMS monitoring in accordance with §117.113(f) of this title; or

(2) if the NO_x monitor is a PEMS, the methods specified in 40 Code of Federal Regulations 75.46.

(f) The owner or operator of any utility boiler subject to a system cap shall maintain daily records indicating the NO_x emissions and fuel usage from each utility boiler and summations of total NO_x emissions and fuel usage for all utility boilers under the system cap on a daily basis. Records shall also be retained in accordance with §117.119 of this title (relating to Notification, Record keeping, and Reporting Requirements).

(g) The owner or operator of any utility boiler subject to a system cap shall report any exceedance of the system 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 to the regional office 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 §117.119 of this title.

(h) The owner or operator of any utility boiler subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(i) A utility boiler which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit. The source cap emission limit is calculated in accordance with subsection (b) of this section.

(j) Emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 of this title may not be included in the baseline for establishing the cap.

(k) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected utility boiler that is operating during a startup, shutdown, or upset period shall be calculated from the NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x monitor nor the substitute data procedure are operating properly, the owner or operator must use the maximum daily rate measured during the initial demonstration of compliance, unless the owner or operator provides data demonstrating to the satisfaction of the executive director that actual emissions were less than maximum emissions during such periods.

§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 in Ozone Nonattainment Areas) must be tested as follows.

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

(3) Testing shall be performed in accordance with the schedules specified in §117.510 [§117.510(4) and (5)] of this title (relating to Compliance Schedule For Utility Electric Generation in Ozone Nonattainment Areas).

(b) - (c) (No change.)

(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) For utility boilers complying with §117.108 of this title (relating to System Cap), a rolling 30-day average of total daily pounds of NO_x emissions from the utility boilers are monitored (or calculated in accordance with §117.108(e) of this title) for 30 successive system 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.

(4) [(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.

(5) [(4)] To comply with the CO emission limit in parts per million by volume on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission limit. The

rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

§117.113. Continuous Demonstration of Compliance.

(a) NO_x monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas), 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) - (e) (No change.)

(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 this division [§117.105 or §117.107 of this title (relating to Emission Specifications and Alternative System-wide Emission Specifications)].

(1) - (4) (No change.)

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

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

(h) - (i) (No change.)

(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 division [title] shall be permanently withdrawn.

(2) - (3) (No change.)

(k) - (l) (No change.)

§117.115. Final Control Plan Procedures for Reasonably Available Control Technology.

(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 §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) [division]. The report must include a list of all units listed in §117.101 of this title, showing:

(1) (No change.)

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

(A) - (C) (No change.)

(D) Section 117.570 of this title (relating to Trading);

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

(b) - (d) (No change.)

§117.116. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of utility boilers listed in §117.101 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit to the executive director a final control report to show compliance with the requirements of §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations). The report must include:

(1) the section under which NO_x compliance is being established for the utility boilers within the electric generating system, either:

(A) §117.106 of this title; or

(B) §117.108 of this title (relating to System Cap); and as applicable,

(C) §117.570 of this title (relating to Trading);

(2) the methods of control of NO_x emissions for each unit;

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

(4) 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

(5) the specific rule citation for any utility boiler with a claimed exemption from the emission specification of §117.106 of this title.

(b) For sources complying with §117.108 of this title, 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 system cap allowable emission rates; and

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

(A) the average daily heat input H_i specified in §117.108(c)(1) of this title;

(B) the maximum daily heat input H_{mi} specified in §117.108(c)(2) of this title;

(C) the method of monitoring emissions; and

(D) the method of providing substitute emissions data when the NO_x monitoring system is not providing valid data.

(3) an explanation of the basis of the values of H_i and H_{mi}.

(c) 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 in Ozone Nonattainment Areas). 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 the system cap rolling 30-day average emission limit, 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 in Ozone Nonattainment Areas). For sources complying with §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations, 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, Recordkeeping, and Reporting Requirements.

(a) (No change.)

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

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

(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) (No change.)

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

(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.

(A) 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.

(B) For utility boilers complying with §117.108 of this title (relating to System Cap), excess emissions are each daily period for which the total nitrogen oxides (NO_x) emissions exceed the rolling 30-day average or the maximum daily NO_x cap.

(2) - (5) (No change.)

(e) (No change.)

§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 for Reasonably Available Control Technology (RACT)), or the carbon monoxide or ammonia limits of §117.106(c) of this title Relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.105 of this title for that unit. The executive director:

(1) - (3) (No change.)

(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) or §50.139 of this title (relating to Overturn Executive Director's Decision) 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 in Ozone Nonattainment Areas).

SUBCHAPTER B : UTILITY ELECTRIC GENERATION

§117.109

STATUTORY AUTHORITY

The repeal is proposed under the TCAA, Texas Health and Safety Code, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; and §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air.

The repeal implements the Texas Health and Safety Code, TCAA, §§382.011, 382.012, and 382.017.

§117.109. Initial Control Plan Procedures.

DIVISION 3 [2] : INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL[, AND INDUSTRIAL] COMBUSTION SOURCES IN OZONE NONATTAINMENT ARIES

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

STATUTORY AUTHORITY

The amendments are proposed under Texas Health and Safety Code, TCAA, §382.011, which establishes the ability of the commission to control the quality of the state's air; §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.

The proposed amendments implement Texas Health and Safety Code, §382.012.

§117.201. Applicability.

The provisions of this division (relating to Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas), 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) - (3) (No change.)

§117.203. Exemptions.

Units exempted from the provisions of this division (relating to Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas), 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) - (8) (No change.)

§117.205. Emission Specifications for Reasonably Available Control Technology (RACT).

(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 Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas) 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) - (f) (No change.)

(g) No person shall allow the discharge into the atmosphere from any unit subject to a NO_x emission limit in this section, (including an alternative to the NO_x limit in this section under §117.207 or §117.223 of this title) [division (relating to Commercial, Institutional, and Industrial Sources)], ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(h) (No change.)

§117.206. Emission Specifications for Attainment Demonstrations.

(a) Beaumont/Port Arthur. No person shall allow the discharge into the atmosphere from any gas-fired boiler or process heater with a maximum rated capacity equal to or greater than 40 million (MM) Btu/hr in the Beaumont/Port Arthur ozone nonattainment area, emissions of nitrogen oxides (NO_x) in excess of the following, except as provided in subsections (d) and (e) of this section:

(1) boilers, 0.10 pound (lb) NO_x per MMBtu of heat input; and

(2) process heaters, 0.08 lb NO_x per MMBtu of heat input.

(b) Dallas/Fort Worth. No person shall allow the discharge into the atmosphere in the Dallas/Fort Worth ozone nonattainment area, emissions in excess of the following, except as provided in subsections (d) and (e) of this section:

(1) gas-fired boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr, 30 parts per million by volume (ppmv) NO_x, at 3% oxygen (O_2), dry basis; and

(2) gas-fired and gas/liquid-fired, lean-burn, stationary reciprocating internal combustion engines rated 300 horsepower or greater, 2.0 grams NO_x per horsepower hour (g NO_x/hp-hr) and 3.0 g CO/hp-hr.

(c) NO_x averaging time. The emission limits of subsections (a) and (b) of this section shall apply:

(1) if the unit is operated with a NO_x continuous emission monitors (CEMS) or predictive emission monitors (PEMS) under §117.213 of this title (relating to Continuous Demonstration of Compliance), either as:

(A) a rolling 30-day average period, in the units of the applicable standard;

(B) a block one-hour average, in the units of the applicable standard, or alternatively;

(C) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in lb NO_x per MMBtu; and

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.213 of this title, a block one-hour average, in the units of the applicable standard. Alternatively for boilers and process heaters, the emission limits may be applied in lbs per hour, as specified in paragraph (1)(C) of this subsection.

(d) Related emissions. 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, emissions in excess of the following, except as provided in §117.221 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO), 400 ppmv at 3.0% O_2, dry basis;

(A) on a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO; and

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO; and

(2) ammonia emissions, 5 ppmv on a block one-hour averaging period.

(e) Compliance flexibility.

(1) An owner or operator may use any of the following alternative methods to comply with the NO_x emission specifications of this section:

(A) §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications);

(B) §117.223 of this title (relating to Source Cap); or

(C) §117.570 (relating to Trading).

(2) Section 117.221 of this title (relating to Alternative Case Specific Specifications) is not an applicable method of compliance with the NO_x emission specifications of this section.

(3) An owner or operator may petition the executive director for an alternative to the CO or ammonia limits of this section in accordance with §117.221 of this title.

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

(1) any commercial, institutional, or industrial boiler or process heater with a maximum rated capacity less than 40 MMBtu/hr; and

(2) units exempted from emission specifications in §117.205(h)(2)-(5) of this title.

§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 for Reasonably Available Control Technology (RACT)) or §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations 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 in [as]:

(A) the units of the applicable standard (the mass of NO_x emitted per unit of energy input (pound NO_x per million (MM) Btu) or parts per million by volume), on a rolling 30-day average period; or

(B) (No change.)

(2) - (4) (No change.)

(c) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from gaseous fuel shall use only the appropriate gaseous fuel emission limit of

§117.205 or §117.206 of this title at maximum rated capacity in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate while firing gas, calculated in accordance with subsection (a) of this section. The owner or operator shall also:

(1) - (3) (No change.)

(d) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from liquid fuel shall use a heat input weighted sum of the appropriate gaseous and liquid fuel emission specifications of §117.205 or §117.206 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(e) (No change.)

(f) Units exempted from emission specifications in accordance with §117.205(h) and §117.206(e) 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(h) and §117.206(e) 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) (No change.)

(2) The ammonia and carbon monoxide emission specifications of §117.205 and §117.206 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 lowest [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, or when applicable, subsection (i) of this section.

(4) (No change.)

(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 lowest of the emission specifications of §117.205 of this title, or when applicable, §117.206 of this title, or any applicable permit emission specification identified in subsection (i) of this section, 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 in pound per MMBtu [of §117.205of 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) (No change.)

(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 NOx emission specification of §117.205 of this title

(A) - (C) (No change.)

<u>(D) This paragraph is not applicable for establishing compliance with §117.206 of this title.</u>

(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. <u>This subsection is not applicable to:</u>

(1) units under subsection (g)(4) of this section;

(2) increase limits set by permit; or

(3) establish compliance with §117.206 of this title.

(i) When using this section for establishing alternative compliance with §117.206 of this title, the individual NO_x emission limit that is to be used in calculating the alternative plant-wide emission specifications is the lowest of the specification of §117.206 of this title, the actual emission rate as of September 1, 1997, and any applicable permit emission specification:

(1) for units in the Beaumont Port Arthur ozone nonattainment area, in effect on September 10, 1993;

(2) for units in the Dallas/Fort Worth ozone nonattainment area, in effect on September 1, 1997.

§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 for Reasonably Available Control Technology (RACT)) in compliance with those limitations.

(b) - (c) (No change.)

(d) All units subject to the emission limitations of §§117.205, 117.206 (relating to Emission Specifications for Attainment Demonstrations), 117.207, or 117.223 of this title shall be operated so as to minimize NO_x emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

(1) Each boiler, except for wood-fired boilers,shall be operated with oxygen (O_2) [or], carbon monoxide (CO), or fuel trim [(or both)].

(2) - (7) (No change.)

§117.209. Initial Control Plan Procedures.

(a) - (b) (No change.)

(c) The initial control plan shall be submitted by April 1, 1994 [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) (No change.)

(2) identification of all units subject to the emission specifications of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap);

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

(7) a list of any units which have been or will be retired, decommissioned, or shutdown and rendered inoperable after November 15, 1990 as a result of compliance with §117.205 of this title [this regulation], indicating the date of occurrence or anticipated date of occurrence;

(8) - (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 Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas).

(1) - (3) (No change.)

(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 Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas).

(b) - (g) (No change.)

§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.

(1) (No change.)

(2) As an alternative to the fuel flow monitoring requirements of this subsection, units operating with a nitrogen oxides (NO_x) and diluent continuous emission monitoring system (CEMS) under subsection (e) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR 60, Appendix B, Performance Specification 6 or 40 CFR 75, Appendix A.

(b) (No change.)

(c) NO_x monitors.

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

(A) - (B) (No change.)

(C) boilers and process heaters located in the Beaumont/Port Arthur ozone nonattainment area which are vented through a common stack and the total rated heat input from the units combined is greater than or equal to 250 MMBtu/hr and the annual heat input combined is greater than $2.2(10^{11})$ Btu/yr;

(D) [(C)] stationary gas turbines with an MW rating greater than or equal to 30 MW operated more than 850 hours per year;

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

(F) [(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(h)(3)-(5) of this title (relating to Emission Specifications for Reasonably Available Control Technology); and

(B) (No change.)

(d) (No change.)

(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) - (B) (No change.)

(C) After the final compliance date, audits in accordance with §5.1 of Appendix F, quality assurance procedures for NO_x, CO and diluent analyzers, 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 §5.1.1.

(2) Monitor diluent, either O_2 or CO_2, unless using an exhaust flow meter as provided in subsection (a)(2) of this section.

(3) - (4) (No change.)

(f) - (k) (No change.)

(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 for Reasonably Available Control Technology).

(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(h)(2) of this title (relating to Definitions), 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 division [title] shall be permanently withdrawn.

(2) - (3) (No change.)

§117.215. Final Control Plan Procedures for Reasonably Available Control Technology.

(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 §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) [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) - (6) (No change.)

(b) - (d) (No change.)

(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 Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas. 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.

§117.216. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of units listed in §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.206 of this title. The report must include:

(1) the section under which NO_x compliance is being established, either:

(A) Section 117.206 of this title;

(B) Section 117.223 of this title (relating to Source Cap); or

(C) Section 117.570 of this title (relating to Trading);

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

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

(4) 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

(5) the specific rule citation for any unit with a claimed exemption from the emission specification of §117.206 of this title.

(b) For sources complying with §117.223 of this title, 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 average daily heat input H_i specified in §117.223(b)(1) and (k) or (l) of this title;

(B) the maximum daily heat input H_{mi} specified in §117.223(b)(2) and (k) or (l) of this title;

(C) the method of monitoring emissions; and

(D) the method of providing substitute emissions data when the NO_x monitoring system is not providing valid data.

(3) an explanation of the basis of the values of H_i and H_{mi}.

(c) The report must be submitted to the executive director by the applicable date specified for final control plans in §117.520(a) or (b) of this title (relating to Compliance Schedule For Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas). 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 the source cap rolling 30-day average emission limit, 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 Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas).

(1) For sources complying with §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations), or §117.207 of this title (relating to Alternative Plant-wide Emission Specifications), replacement new units may be included in the control plan.

(2) 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.

(3) 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) - (b) (No change.)

(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) (No change.)

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

(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 Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas) 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 (relating to Emission Specifications for Reasonably Available Control Technology (RACT)).

(B) (No change.)

(2) - (5) (No change.)

(e) Reporting for engines. The owner or operator of any rich-burn engine subject to the emission limitations in §§117.205, 117.206 (relating to Emission Specifications for Attainment Demonstrations), or [§]117.207 [of this title] (relating to Alternative Plant-wide Emission Specifications) 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) - (2) (No change.)

(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) (No change.)

(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) (No change.)

(B) (No change.)

(3)-(8) (No change.)

§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 for Reasonably Available Control Technology (RACT)) or the carbon monoxide or ammonia limits of §117.206(d) of this title Relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.205 of this title for that unit. The executive director:

(1) - (3) (No change.)

(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) or §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) 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 Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas).

§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 for Reasonably Available Control Technology (RACT)) or §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations), 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 or §117.206 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, 117.206, 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:

Figure: 30 TAC §117.223(b)(1)

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

Where:

I = each emission unit in the emission cap

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

H_i = (A) For compliance with §117.205(a)-(d) of this title. 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.

(B) For compliance with §117.205(e) or §117.206 of this title. The actual historical average of the daily heat input for each unit included in the source cap, in MMBtu per day, as certified to the executive director, for a 24 consecutive month period between January 1, 1997 and December 31, 1999. 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 compliance with §117.205(a)-(d) of this title.

(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.

(ii) [(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.

(B) For compliance with §117.205(e) or §117.206 of this title, the lowest of:

(i) the appropriate limit of §§117.205(e), 117.206, or 117.207(f) of this title;

(ii) any permit emission 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, in the:

(I) Beaumont Port Arthur ozone nonattainment area, in effect on September 10, 1993; and

(II) Dallas/Fort Worth ozone nonattainment area, in effect on September 1, 1997; and

(iii) the actual emission rate as of the dates specified in clause (ii) of this subparagraph. All calculations of emission rates shall presume that emission controls in effect on the dates specified in clause (ii) of this subparagraph are in effect for the two-year period used in calculating the actual heat input.

(2) - (3) (No change.)

(4) The owner or operator at its option may include any of the entire classes of exempted units listed in §117.207(f) of this title in a source cap. For compliance with §117.205(a)-(d) of this title, such [Such] units shall be required to reduce emissions available for use in the cap by an additional amount calculated in accordance with the United States Environmental Protection Agency's

proposed Economic Incentive Program rules for offset ratios for trades between RACT and non-RACT sources, as published in the February 23, 1993, Federal Register (58 FR 11110).

(5) - (6) (No change.)

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

(f) The owner or operator shall demonstrate initial compliance with the source cap in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas).

(g) For compliance with §117.205(a)-(d) of this title by November 15, 1999, a [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) - (5) (No change.)

[(6) Shutdowns which occurred before September 10, 1993, may not be used for compliance with the lean-burn engine specification of §117.205(e) of this title.]

(h) For compliance with §117.205(e) or §117.206 of this title, a unit which has been permanently retired or decommissioned and rendered inoperable may be included in the source cap under the following conditions:

(1) shutdowns must have occurred after the following dates:

(A) September 10, 1993, in the Beaumont/Port Arthur ozone nonattainment area.

(B) September 1, 1997, in the Dallas/Fort Worth ozone nonattainment area.

(2) the source cap emission limit for retired units is calculated in accordance with subsection (b) of this section;

(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, 1997, and December 31, 1999, the actual heat input shall be the average daily heat input for the continuous time period that the unit was in service, consistent with the heat input used to represent the unit's emissions in the attainment demonstration modeling inventory. 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) the owner or operator shall certify the unit's operational level and maximum rated capacity; and

(5) emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 of this title may not be included in the baseline for establishing the cap.

(i) [(h)] A unit which has been shut down and rendered inoperable after June 9, 1993, but not permanently retired, should be identified in the initial control plan and may be included in the source cap to comply with the NO_x emission specifications of this division:

(1) applicable in the Houston/Galveston or Beaumont/Port Arthur ozone nonattainment areas, required by November 15, 1999; or

(2) applicable in the Dallas/Fort Worth ozone nonattainment area, required by March 31, 2001.

(j) [(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 for Reasonably Available Control Technology) the information necessary under this section to demonstrate initial compliance with the source cap.

(k) [(j)] For the purposes of determining compliance with the source cap emission limit, the contribution of each affected unit that is operating during a startup, shutdown, or upset period shall be calculated from the NO_x emission rate, as measured by the initial demonstration of compliance, for that unit, unless the owner or operator provides data demonstrating to the satisfaction of the executive director that actual emissions were less than maximum emissions during such periods.

[(k) The modified requirements of this subsection are necessary for an owner or operator to use the source cap requirements of this section to achieve compliance with the lean-burn engine NO_x emission specification of §117.205(e) of this title.]

[(1) In subsection (b) of this section, the dates are modified in the definitions as follows:]

[(A) H_i, the actual historical average daily heat input, the time period between January 1, 1997, and December 31, 1999, replaces the time period between January 1, 1990, and

June 9, 1993; and]

[(B) R_i, December 31, 1999, replaces June 9, 1993, throughout.]

[(2) In subsection (g) of this section, the dates are modified as follows:]

[(A) September 10, 1993, replaces November 15, 1990, throughout;]

[(B) December 31, 1999, replaces June 9, 1993, throughout; and]

[(C) January 1, 1997, replaces January 1, 1990.]

[(3) The actual heat input identified in subsection (g)(3) of this section must be consistent with the heat input used to represent the unit's emissions in the attainment demonstration modeling inventory.]

[(4) A source which used a source cap to comply with the NO_x emission specifications of this division required by November 15, 1999, must either:]

[(A) maintain a separate source cap for the lean-burn engines; or]

[(B) revise an existing source cap to include the lean-burn engines, recalculating the allowable mass emission rates for all units in the cap based on the conditions in paragraphs (1) - (3) of this subsection.]

SUBCHAPTER E [D]: ADMINISTRATIVE PROVISIONS

§§117.510, 117.520, 117.570

STATUTORY AUTHORITY

The amendments are proposed under Texas Health and Safety Code, TCAA, §382.011, which establishes the ability of the commission to control the quality of the state's air; §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.

The proposed amendments implements Texas Health and Safety Code, §382.012.

§117.510. Compliance Schedule For Utility Electric Generation in Ozone Nonattainment Areas.

(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 in Ozone Nonattainment Areas) as soon as practicable, but no later than the dates specified in this subsection [November 15, 1999 (final compliance date)]. [The owner or operator shall:]

(1) Reasonably Available Control Technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date), except as specified in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this subsection, relating to emission specifications for attainment demonstration. [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);]

(A) [(2)] Conduct [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:

(i) [(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

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

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

(C) [(4)] Submit [submit] to the executive director:

(i) [(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;

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

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

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

(III) [(iii)] no later than:

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

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

(D) [(5)] Conduct [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

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

(2) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.106(a) of this title (relating to Emission Specifications for Attainment Demonstrations) as soon as practicable, but no later than:

(A) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.106(a) of this title have been accomplished, as measured either by

(i) the total number of units required to reduce emissions in order to comply with §117.106(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after the effective date of §117.106(a) of this title; or

(ii) the total amount of emissions reductions required to comply with §117.106(a) of this title using the alternative methods to comply, either:

(I) Section 117.108 of this title (relating to System Cap), or

(II) Section 117.570 of this title (relating to Trading);

(B) May 1, 2003, submit to the executive director:

(i) identification of enforceable emission limits which satisfy subparagraph (A) of this paragraph;

(ii) the information specified in §117.116 of this title (relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications) to comply with subparagraph (A) of this paragraph; and

(iii) any other revisions to the source's final control plan as a result of complying with subparagraph (A) of this paragraph;

(C) July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap to comply with subparagraph (A) of this paragraph;

(D) May 1, 2005, comply with §117.106(a) of this title;

(E) May 1, 2005, submit a revised final control plan which contains:

(i) a demonstration of compliance with §117.106(a) of this title;

(ii) the information specified in §117.116 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications §117.106(a) of this title; and

(F) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications §117.106(a) of this title.

(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 the dates specified in this subsection. [March 31, 2001 (final compliance date). The owner or operator shall:]

(1) Reasonably available control technology (RACT). The owner or operator 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), except as provided in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this subsection, relating to emission specifications for attainment demonstration.

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

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

(C) [(3)] Submit [submit] to the executive director:

(i) [(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;

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

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

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

(III) [(iii)] no later than:

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

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

(D) [(4)] Conduct [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

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

(2) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.106(b) of this title (relating to Emission Specifications for Attainment Demonstrations) as soon as practicable, but no later than:

(A) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.106(b) of this title have been accomplished, as measured either by

(i) the total number of units required to reduce emissions in order to comply with §117.106(b) of this title using direct compliance with the emission specifications, counting only units still required to reduce after the effective date of 117.106(b) of this title; or

(ii) the total amount of emissions reductions required to comply with §117.106(b) of this title using the alternative methods to comply, either:

(I) Section 117.108 of this title (relating to System Cap), or

(II) Section 117.570 (relating to Trading);

(B) May 1, 2003, submit to the executive director:

(i) identification of enforceable emission limits which satisfy subparagraph (A) of this paragraph;

(ii) the information specified in §117.116 of this title (relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications) to comply with subparagraph (A) of this paragraph; and

(iii) any other revisions to the source's final control plan as a result of complying with subparagraph (A) of this paragraph;

(C) July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap to comply with subparagraph (A) of this paragraph;

(D) May 1, 2005, comply with §117.106(b) of this title;

(E) May 1, 2005, submit a revised final control plan which contains:

(i) a demonstration of compliance with §117.106(b) of this title;

(ii) the information specified in §117.116 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications §117.106(b) of this title; and

(F) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications §117.106(b) of this title.

(c) The owner or operator of each electric utility in the Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than November 15, 1999 (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 according to the following schedules:

(A) for equipment and software required pursuant to 40 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;

(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 CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title; 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;

(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 November 15, 1999.

§117.520. Compliance Schedule For Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas.

(a) The owner or operator of each commercial, institutional, and industrial source in the Beaumont/Port Arthur ozone nonattainment area shall comply with the requirements of Subchapter B, Division 2 of this chapter (relating to Industrial, Commercial, and Institutional[, and Industrial] Combustion Sources in Ozone Nonattainment Areas) as soon as practicable, but no later than the dates specified in this subsection. [The owner or operator shall:]

(1) Reasonably available control technology (RACT). The owner or operator shall for all units, [except lean-burn engines subject to paragraph (2) of this subsection,] comply with the requirements of Subchapter B, Division 2 of this chapter, except as specified in paragraph (2) (relating to lean-burn engines) and paragraph (3) of this subsection (relating to emission specifications for attainment demonstration), by November 15, 1999 (final compliance date) and submit to the executive director:

(A) - (D) (No change.)

(2) Lean-burn engines. The owner or operator shall for each lean-burn, stationary, reciprocating internal combustion engine subject to §117.205(e) of this title (relating to Emission

Specifications), comply with the requirements of Subchapter B, Division 2 of this chapter for those engines as soon as practicable, but no later than November 15, 2001 (final compliance date for lean-burn engines); and

(A) - (B) (No change.)

(3) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.206(a) of this title (relating to Emission Specifications for Attainment Demonstrations) as soon as practicable, but no later than

(A) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.206(a) of this title have been accomplished, as measured either by

(i) the total number of units required to reduce emissions in order to comply with §117.206(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after the effective date of §117.206(a) of this title; or

(ii) the total amount of emissions reductions required to comply with §117.206(a) of this title using the alternative methods to comply, either:

(I) §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications);

(II) §117.223 of this title (relating to Source Cap), or

(III) §117.570 of this title (relating to Trading);

(B) May 1, 2003, submit to the executive director:

(i) identification of enforceable emission limits which satisfy the conditions of subparagraph (A) of this paragraph;

(ii) for units operating without CEMS or PEMS or for units operating with CEMS or PEMS and complying with the NO_x emission limit on an hourly average, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title;

(iii) for units newly operating with CEMS or PEMS to comply with the monitoring requirements of §117.213(c)(1)(C) of this title or §117.223 of this title, 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;

(iv) the information specified in §117.216 of this title (relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications); and

(v) any other revisions to the source's final control plan as a result of complying with the emission specifications §117.206(a) of this title;

(C) July 31, 2003, submit to the executive director:

(i) the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title, for units complying with the NO_x emission limit on a rolling 30-day average; and

(ii) the first semiannual report required by §117.213(c)(1)(C), §117.219(e), and §117.223(e) of this title, covering the period May 1, 2003 through June 30, 2003;

(D) May 1, 2005, comply with §117.206(a) of this title;

(E) May 1, 2005, submit a revised final control plan which contains:

(i) a demonstration of compliance with §117.206(a) of this title;

(ii) the information specified in §117.216 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications §117.206(a) of this title; and

(F) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title, if using the 30-day average source cap NO_x emission limit to comply with the emission specifications §117.206(a) of this title.

(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, 2002 [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, 2002 [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, 2002 [2001];

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

(i) - (ii) (No change.)

(iii) no later than:

(I) March 31, 2002 [2001], for units complying with the NO_x emission limit on an hourly average; and

(II) May 31, 2002 [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, 2002 [2001]; and

(D) the first semiannual report required by §117.219(d) or (e) of this title, covering the period March 31, 2002 [2001] through June 30, 2002 [2001], no later than July 31, 2002 [2001].

(c) (No change.)

§117.570. Trading.

(a) An owner or operator may reduce the amount of emission reductions required by §117.105 or §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.106 or §117.206 of this title (relating to Emission Specifications for

Attainment Demonstrations), §117.107 of this title (relating to Alternative System-Wide Emission Specifications), §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), §117.108 of this title (relating to System Cap), or §117.223 of this title (relating to Source Cap) by obtaining an emission reduction credit (ERC), mobile emission reduction credit (MERC), discrete emission reduction credit (DERC), or mobile discrete emission reduction credit (MDERC) established in accordance with this section and §101.29 of this title (relating to Emission Credit Banking and Trading). Any ERCs or DERCs for nitrogen oxides (NO_x) generated under the provisions of §101.29 of this title used for the purposes of this chapter become subject to the limitations and provisions of this section. For the purposes of this section, the term "RC" refers to an ERC, MERC, DERC, or MDERC whichever is applicable.

(b) Reduction credits (RCs) shall be generated as follows.

(1) For sources not subject to the emission specifications of §§117.105, [or §]117.205, or 117.206 of this title, creditable RCs used to meet compliance with those sections shall be established in accordance with the following requirements:

(A) The source shall use emissions test data to establish the actual emissions baseline in accordance with the testing requirements of §117.209(b) of this title (relating to Initial Control Plan Procedures), or §117.111 or §117.211 of this title (relating to Initial Demonstration of Compliance), as applicable. The actual emissions baseline is defined as the actual annual emissions, in tons per year, from a source determined by use of data representative of actual operations

(i) in 1990 or later, for compliance with emission specifications required for reasonably available control technology under §117.105 or §117.205(a)-(d) of this title;

(ii) after September 10, 1993 for compliance with emission specifications required for the Beaumont/Port Arthur ozone attainment demonstration under §§117.106, 117.205(e), or 117.206 of this title;

(iii) after 1997 for compliance with emission specifications required for the Dallas/Fort Worth ozone attainment demonstration under §117.106 or §117.206 of this title;

(iv) assuming full compliance with all applicable state and federal rules and regulations;

(B) (No change.)

(2) For sources subject to the emission specifications of §§117.105, [or] §117.205, or 117.206, of this title creditable RCs shall be calculated using the following equations:

Figure: 30 TAC §117.570(b)(2)

$$\text{ERCs (tons per year)} = \sum_{j=1}^{N} \left[H_j \times (R_{Aj} - R_{Bj}) \times \frac{365}{2000} \right]$$

$$\text{DERCs (tons)} = \sum_{j=1}^{N} \left[H_j \times (R_{Aj} - R_{Bj}) \times \frac{d}{2000} \right]$$

or

Where:

j = each emission unit subject to this section generating RCs

N = the total number of emission units subject to this section generating RCs

H_j = actual daily heat input, in million British thermal units (MMBtu) per day, as calculated according to:

(i) §117.223(b)(1) of this title, except that the term may not include one standard deviation of the average daily heat input for the period;[,] or

(ii) for units that have been shutdown

(I) prior to June 9, 1993, as calculated according to §117.223(g)(3) of this title.[;] except that the term may not include one standard deviation of the average daily heat input for the period [in either calculation.]for compliance with §117.105 or §117.205(a)-(d) of this title; or

(II) in accordance with 117.223(h) of this title, for compliance with §§117.106, 117.205(e), or 117.206 of this title.

R_{Aj} = (A) For ERCs:

(i) For compliance with §117.105 or §117.205(a)-(d) of this title, the lowest of

(I) [(i)] any applicable federally enforceable emission limitation;

(II) [(ii)] the reasonably available control technology (RACT) limit of §117.105 or §117.205(b)-(d) of this title; or

(III) [(iii)] the actual emission rate as of June 9, 1993, in pound (lb)/MMBtu, that apply to emission unit *j* in the absence of trading.

For units that have been shut down prior to June 9, 1993, the actual emission rate shall be considered to be the average annual emission rate occurring over the period used to define the unit's baseline heat input, H_j.

(ii) For compliance with §§117.106, 117.205(e), or §117.206 of this title, the lowest of:

(I) the appropriate limit of §§117.205(e), 117.206, or 117.207(f) of this title;

(II) any permit emission 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, in the:

(-a-) Beaumont Port Arthur ozone nonattainment area, in effect on September 10, 1993; and

(-b-) Dallas/Fort Worth ozone nonattainment area, in effect on September 1, 1997; and

(III) the actual emission rate as of the dates specified in subclause (II) of this clause. All calculations of emission rates shall presume that emission controls in effect on the dates specified in subclause (II) of this clause are in effect for the two-year period used in calculating the actual heat input.

(B) For DERCs, [:] the lower of:

(i) any enforceable emission limitation applicable during the generation period; or

(ii) the baseline emission rate defined in §101.29(a)(7) of this title (relating to Emissions Banking), in lb/MMBtu.

R_{Bj} = (A) For ERCs:
the enforceable emission rate, in lb/MMBtu, for unit *j* established in the registration under subsection (e) of this section;
(B) For DERCs:
the average emission rate, in lb/MMBtu, for unit *j* during the generation period

d = the number of days in the generation period

(3) RCs from shutdown units may be generated only by units participating in a source cap in accordance with §117.223 of this title.

(4) For units participating in a source cap in accordance with §117.223 of this title, creditable RCs may be generated only under the following conditions:

(A) The source cap allowable must be reduced by the amount of any creditable ERCs claimed for the unit or units, and

(B) the actual historical average of the daily heat input for the unit or units may not include one standard deviation of the actual average daily heat input for the period for which creditable reductions are claimed.

(c) Reduction credits shall be used as follows.

(1) An owner or operator complying with §117.223 of this title may reduce the amount of emission reductions otherwise required by complying with the following equations instead of the equations in §117.223(b)(1) and (2) of this title.

Figure: 30 TAC §117.570(c)(1)

ERCs or MERCS:

$$\text{New 30-day rolling average emission limit (lb/day)} = \sum_{i=1}^{N} \left[(H_i \times R_i) + \left(RC_i \times \frac{2000}{365} \right) \right]$$

or

DERCs or MDERCS:

$$\text{New 30-day rolling average emission limit (lb/day)} = \sum_{i=1}^{N} \left[(H_i \times R_i) + \left(\frac{RC_i \times 2000}{d} \right) \right]$$

Where:

R_i, in lb/MMBtu, is defined as in §117.223(b)(1) of this title

i = each emission unit in the source cap

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

H_i = actual daily heat input, in MMBtu per day, as calculated according to §117.223(b)(1) of this title

RC_i = RC used for each unit, in tons per year (for ERCs or MERCs) or tons (for DERCs), generated in accordance with subsection (b) of this section. If RC_i is from a unit not subject to the emission specifications of §§117.105, 117.106, [or] §117.205, or 117.206 of this title, this term becomes Rc_i/F, where F is the offset ratio for the ozone nonattainment area where the unit is located (e.g. 1.2 for Beaumont/Port Arthur and 1.3 for Houston/Galveston).

d = the number of days in the use period

and

ERCs or MERCs:

$$\text{New maximum daily emission limit (lb/day)} = \sum_{i=1}^{N}\left[(H_{Mi} \times R_i) + \left(RC_i \times \frac{2000}{365}\right)\right]$$

or

DERCs or MDERCs:

$$\text{New maximum daily emission limit (lb/day)} = \sum_{i=1}^{N} \left[(H_{Mi} \times R_i) + \left(\frac{RC_i \times 2000}{d} \right) \right]$$

Where:

i and N are defined as in the first equation in this paragraph

R_i, in lb/MMBtu, is defined as in §117.223(b)(1) of this title

H_{Mi} = the maximum daily heat input, in MMBtu/day, as defined in §117.223(b)(2) of this title.

d = the number of days in the use period

(2) An owner or operator complying with §§117.105, 117.106, [§]117.107, [§]117.205, 117.206, [or] §117.207 of this title may reduce the amount of emission reduction otherwise required by those sections for a unit or units at a major source by complying with individual unit emission limits calculated from the following equation:

Figure: 30 TAC §117.570(c)(2)

DERCs or MDERCs:

$$\text{New emission limit for unit i (lb/MMBtu)} = R_{Ai} + \left(\frac{RC_i}{H_{Mi}} \times \frac{2000}{365} \right)$$

Where:

DERCs or MDERCs:

$$\text{New emission limit for unit i (lb/MMBtu)} = R_{Ai} + \left(\frac{RC_i}{H_{Mi}} \times \frac{2000}{d} \right)$$

i = each emission unit subject to this section

N = the total number of emission units subject to this section

R_{Ai} = (A) For ERCs:

(i) For compliance with §117.105 or §117.205(a)-(d) of this title, the lowest of

(I) any applicable federally enforceable emission limitation; [,]

(II) the RACT limit of §117.105 or §117.205(b)-(d) of this title; [,] or

(III) the actual emission rate as of June 9, 1993, in lb/MMBtu, that apply to emission unit i in the absence of trading.

For units that have been shut down prior to June 9, 1993, the actual emission rate shall be considered to be the average annual emission rate occurring over the period used to define the unit's baseline heat input [period in §117.223(g)(3) of this title].

(ii) For compliance with §§117.106, 117.205(e), or 117.206 of this title, the lowest of:

(I) the appropriate limit of §§117.205(e), 117.206, or 117.207(f) of this title;

(II) any permit emission 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, in the:

(-a-) Beaumont Port Arthur ozone nonattainment area, in effect on September 10, 1993; or

(-b-) Dallas/Fort Worth ozone nonattainment area, in effect on September 1, 1997; or

(III) the actual emission rate as of the dates specified in subclause (II) of this clause. All calculations of emission rates shall presume that emission controls in effect on the dates specified in subclause (II) of this clause are in effect for the two-year period used in calculating the actual heat input.

(B) For DERCs, the lower of:

(i) any enforceable emission limitation applicable during the generation period; or

(ii) the baseline emission rate defined in §101.29(a)(7) of this title, in lb/MMBtu.

d = the number of days in the use period

and

H_{Mi} and RC_i are defined as in paragraph (1) of this subsection.

The appropriate compliance averaging period specified in §§117.105, 117.106, [§]117.107, [§]117.205, 117.206, [or] §117.207 of this title shall be assigned to unit *i* using a RC in accordance with the provisions of this paragraph.

(3) RCs from shutdown units may be used only by units participating in a source cap in accordance with §117.223 of this title.

(d) Any lower NO_x emission specification established by rule or permit for the unit or units generating an ERC shall require the user of the ERC to obtain an approved new reduction credit or otherwise reduce emissions prior to the effective date of such rule or permit change. For units using an ERC in accordance with this section which are subject to new, more stringent rule or permit limitations, the owner or operator using the ERC shall submit a revised final control plan to the executive director in accordance with §117.117 or §117.217 of this title (relating to Revision of Final Control Plan) to revise the basis for compliance with the emission specifications of this chapter. The owner or operator using the ERC shall submit the revised final control plan as soon as practicable, but no later than 90 days prior to the effective date of the new, more stringent rule or permit limitations. In addition, the owner or operator of a unit generating the ERC shall submit a revised registration application to the executive director, in accordance with subsection (e)(1) of this section, within 90 days prior to the effective date of any new, more stringent rule or permit limitations affecting that unit. If a more stringent NO_x emission specification is established by rule or permit for the unit or units generating the ERC, the value of the ERC shall be recalculated as follows:

Figure: 30 TAC §117.570(d)

ERCs:

$$\text{Recalculated ERC (tons per year)} = \sum_{j=1}^{N} \left[H_j \times \left(R_{Bj} - R_{Aj-new} \right) \times \frac{365}{2000} \right]$$

Where:

j, N, H_j and R_{Bj} are defined as in subsection (b)(2) of this section

R_{aj-new} = the new NO_x emission specification for unit j, in lb/MMBtu

If the recalculated ERC is of zero or negative value, the ERC is determined to be of zero value.

(e) The RC program established by this section shall be administered as follows:

(1) For emission units subject to the emission specifications of this chapter, which generate ERCs, MERCs, DERCs, or MDERCs and for which the owner or operator elects to comply with the individual emission specifications of §§117.105, 117.106, 117.107, 117.205, 117.206, or 117.207 of this title, the enforceable emission limit R_{Bj} shall be calculated using the maximum rated capacity.

(2) For emission units subject to the emission specifications of this chapter, which generate ERCs, MERCs, DERCs, or MDERCs, and for which the owner or operator elects to achieve compliance using §117.223 of this title, the enforceable emission limit R_{Bj} shall be substituted for R_j in

the source cap allowable mass emission rate equations of §117.223(b)(1) and (2) of this title, and those allowable rates shall be the enforceable limits for those sources.

[(f) Stationary source emission reductions which were relied upon in the attainment demonstration modeling inventory for September 10, 1993 may not be used for generating emission reduction credits to comply with the lean-burn engine NO_x specification of §117.205(e) of this title. The modified requirements of this subsection are necessary for an owner or operator to use the trading requirements of this section to achieve compliance with the NO_x specification of §117.205(e) of this title. The modifications to this section are as follows:]

[(1) in §117.570(b)(1)(A) of this title, 1993 replaces 1990;]

[(2) in §117.570(b)(2) of this title, in the definition of R_{Aj}, December 31, 1999, replaces June 9, 1993;]

[(3) in §117.570(c)(2) of this title, in the definition of R_{Ai}, December 31, 1999, replaces June 9, 1993; and]

[(4) in each instance, references to §§117.223(b)(1), 117.223(b)(2), and 117.223(g)(3) of this title are date-modified in accordance with §117.223(k) of this title.]

SUBCHAPTER E : GAS-FIRED STEAM GENERATION

§117.601

STATUTORY AUTHORITY

The repeal is proposed under the TCAA, Texas Health and Safety Code, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; and §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air.

The repeal implements the Texas Health and Safety Code, TCAA, §§382.011, 382.012, and 382.017.

§117.601. Gas-Fired Steam Generation.