The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts amendments to §§117.101, 117.103, 117.105, 117.107, 117.111, 117.113, 117.115, 117.117, 117.119, and 117.121, 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, Commercial, Institutional, and Industrial Sources; and §§117.510, 117.520 and 117.570, Administrative Provisions. The commission also adopts new §§117.104, 117.106, 117.108, 117.116, 117.206, and 117.216, Combustion at Existing Major Sources. In addition, the commission repeals §117.109, Initial Control Plan Procedures, and §117.601, Gas-Fired Steam Generation.

Sections 117.105-117.108, 117.116, 117.216, 117.223, 117.520, and 117.570 are adopted with changes to the proposed text as published in the December 31, 1999 issue of the *Texas Register* (24 TexReg 11977). The remaining sections and the repeals are adopted without changes and will not be republished.

The adopted changes to Chapter 117 and to the state implementation plan (SIP) 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 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 adopts 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 (Title 42 United States Code (USC) §7410) to demonstrate attainment of the national ambient air quality standard (NAAQS) for ozone.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED 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 one-hour ozone standard.

The emission reduction requirements adopted 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 of 1990 (42 USC §7511a(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 adopted concurrently with these rules, demonstrate that BPA will attain the one-hour ozone standard by 2007.

The adopted rules represent the second and final phase of the state's NO_x rulemaking activities for the BPA attainment demonstration. The rules are being submitted to EPA as revisions to the SIP. The first phase rules, for lean-burn engines in BPA, were submitted to EPA in November 1999.

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 Chapter 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 one 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 adopted rule.

Of the categories not regulated by Chapter 117 contributing more than 1.0% 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 adopted 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 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 ADOPTED 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, 42 USC §7511(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 42 USC, §7410 and §7502(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 adopted rules for DFW in this notice are one element of the ozone attainment demonstration SIP for DFW which underwent public hearing and comment concurrently with these rules. The commission plans to submit this SIP to the EPA in 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 shows that reductions of NO_x in DFW and regionally will be necessary to attain the ozone NAAQS. The current modeling also shows that achieving the ozone NAAQS 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 the emission reductions 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 adopted in this notice are the outcome of a development process which involved the EPA, the commission, local elected officials, citizens, industrial stakeholders, air quality researchers, and hired consultants. Local officials from the DFW area have formally submitted a resolution to the commission requesting the inclusion of many specific emission reduction strategies, including a strategy of significant reductions from electric generating units in DFW.

The NO_x reductions required for the area to attain the ozone NAAQS have 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), 42 USC §7511(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. Hundreds of emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources and mobile sources were analyzed in at least forty modeling iterations, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling submitted for public hearing and comment concurrently with these rules shows that, in order for DFW to achieve the ozone NAAQS by 2007, almost all of the practicably achievable NO_x reductions are necessary from each emission source category, including reductions from counties surrounding the DFW nonattainment area. Therefore, each strategy, including the reductions required by this rulemaking, is crucial to meet federal requirements for the DFW area.

Major stationary sources contribute more than 20% of the total NO_x in the DFW area at the peak of the ozone season, and therefore clearly must be part of the solution. The adopted NO_x emission limits for electric utility and large ICI boilers in this rulemaking approach the maximum practicable emission reductions for these sources. The adopted NO_x emission limits for lean-burn engines effectively limit the emissions from a previously unregulated category of major stationary source NO_x in DFW.

Another purpose of these adopted 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), 42 USC §7511a(f), requires that 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 DISCUSSION

The primary purpose of the adopted revisions is to establish new emission limits for the ozone attainment demonstrations. However, many of the adopted 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 adopted emission limits. These changes strive to maintain consistency with the existing requirements. Where there were reasons to adjust existing compliance requirements, the reasons for the adopted changes are discussed.

An adopted 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 adopted for attainment counties in east and central Texas, published concurrently in a separate section of this issue of the *Texas Register*.

The adopted changes to §117.101, concerning Applicability, and §117.103, concerning Exemptions, update the sections to reflect new names of cross-referenced sections. An additional change to §117.101 clarifies 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 is not required to be a municipality or a PUC regulated utility for the requirements to apply. An additional change to §117.103 deletes the cross-reference to §117.109, concerning Initial Control Plan Procedures, because the section is no longer needed and is repealed.

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 31-county regional area comprising the Houston and Dallas Air Quality Control Regions, since 1972. The limits will cease to apply in DFW on March 31, 2001, the 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 adopted §117.104. Section 117.601 requirements for the affected attainment counties are relocated to a new division for electric utility generation in east and central Texas, as published in a separate section of this issue of the *Texas Register*.

An adopted 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 adopted tighter emission limits necessary to demonstrate attainment. The adopted 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. An equivalent alternate standard based on heat input is also adopted to simplify compliance tracking for monitoring systems which are based on carbon dioxide as the diluent.

The adopted new §117.106, concerning Emission Specifications for Attainment Demonstrations, specifies new NO_x limits for electric utility boilers located in BPA and DFW. The adopted limits are essential components of and consistent with the BPA and DFW ozone attainment demonstration SIPs, which underwent public hearings and comment concurrently with the adopted rules and are now being submitted to EPA. The adopted emission limits and ozone attainment demonstration SIPs are required by 42 USC §7410 and §7511a, which require states to submit SIPs to the EPA which contain enforceable measures to achieve the NAAQS.

The adopted 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 adopted NO_x emission limit for utility boilers in BPA is discussed in the background for BPA section of this preamble notice. The adopted 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. Because four of the five gas-fired utility boilers affected by the adopted limit are tangential-fired, the limit is expected to be achievable with combustion modification techniques.

The adopted NO_x emission limits of §117.106(a) and (b) are based on a daily rate for electric utility boilers. The 24-hour 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 adopted limits of §117.106(b) for utility boilers in DFW are part of a larger set of emission reduction measures for the DFW attainment demonstration SIP. The larger context of development of the adopted NO_x emission limit for utility boilers in DFW is discussed in the background for DFW section of this preamble notice. The adopted rule distinguishes between small and large DFW utility systems, terms which are defined in revised §117.10, published in a separate section of this issue of the *Texas Register*. The emission limits of 0.033 lb NO_x/MMBtu for large DFW utility systems and 0.06 lb NO_x/MMBtu for small DFW utility systems will achieve an 88% emission reduction from DFW electric utility emissions, calculated from the individual system highest 30-day average emissions during 1996-1998. The adopted 88% NO_x reduction is expected to necessitate selective catalytic reduction (SCR) on many of the utility boilers in the DFW area.

The adopted emission limits of §117.106(c) address pollutants which may increase as an incidental result of compliance with the adopted NO_x limits. The adopted CO limit is consistent with the existing CO limit of §117.105(i) because nothing in these rules necessitates changing the existing limit. The adopted ammonia limit of ten ppm is lower than the existing limit of §117.105(j). The adopted 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) (will be referred to as NESCAUM). It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission is excluding 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 will eliminate the need for case-specific SIP revisions by EPA to complete the approval of an alternate CO or ammonia limit.

The adopted §117.106(d) allows NO_x compliance flexibility using the system cap in §117.108 and the existing emission trading provisions in §117.570.

An adopted change to §117.107(a), concerning Alternative System-Wide Emission Specifications, updates the section to reflect a new name of a cross-referenced section. The 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 did not choose to allow the use of §117.107 as an alternative for complying with the new §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 adopted §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 new NO_x limits, the commission has adopted a system-wide cap. The system cap avoids the issue of equivalent emission reductions that is associated with emission averaging.

The adopted new §117.108, concerning System Cap, creates a flexible new alternative to direct compliance with the new §117.106 NO_x emission specifications. The section is patterned on the existing source cap compliance option in §117.223 for ICI combustion sources. The system cap sets limits on total pounds of NO_x allowed to be emitted by an electric utility system. Under the system cap, compliance is not defined by separate emission limits on individual boilers; instead, each boiler operates within the system cap limits. 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 are currently monitoring NO_x continuously under the federal acid rain rules of 40 Code of Federal Regulations (CFR) 75. Only the smaller boilers within the small utility systems in DFW do not monitor NO_x emissions. The existing investment in NO_x monitors is expected to make the system cap an attractive option for electric utilities.

The adopted averaging periods for the NO_x system cap include 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 the historical 1996-1998 system highest 30-day actual emissions. The 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 adopted baseline period for H_i, the historical heat input used in the 30-day rolling average of §117.108(c)(1), is the individual utility system's highest 30-day heat input within 1996-1998. The baseline represents recent highest utility electric demand and emissions during the peak ozone formation months.

Section 117.108 as adopted 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 Chapter 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 repeals §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.

Adopted changes to §117.111, concerning Initial Demonstration of Compliance, update the section to reflect the 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 required for the §117.106 emission limits. New §117.111(d)(3) specifies the procedure for demonstrating initial compliance with the new emission cap of §117.108.

The adopted changes to §117.113, concerning Continuous Demonstration of Compliance, update the section to reflect the 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 new §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 adopted 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 information required for attainment demonstration emission limits in the next section.

The adopted 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 adopted requirements are parallel to existing requirements in §117.115 and §117.215, concerning Final Control Plan Procedures.

The adopted changes to §117.117, concerning Revision of Final Control Plan and §117.119, concerning Notification, Recordkeeping and Reporting Requirements, update the sections to reflect the new names of cross-referenced sections. An additional 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).

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

An adopted 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 adopted rules that apply to cement kilns in the east and central Texas region, published concurrently in a separate section of this issue of the *Texas Register*.

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

An adopted 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 adopted tighter emission limits necessary to demonstrate attainment of the ozone NAAQS. The adopted change to §117.205(a)(3) updates the name of a cross-referenced section and the adopted change to §117.205(g) revises the cross-reference from division to section level to accommodate the new emission specifications within the division.

Adopted 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 adopted limits are essential components of and consistent with the BPA and DFW ozone attainment demonstration SIPs which underwent public hearings and comment concurrently with the adopted rules and are now being submitted to EPA.

The adopted 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 adopted 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 adopted rule would affect seven 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 adopted 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 adopted 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 adopted emission specification of two 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, 42 USC §7410(k), the adopted emission limit would implement NO_x RACT for lean-burn engines in DFW, as required by the FCAA, 42 USC §7511a(f). Analysis of the 1996 emissions inventory indicated that the adopted rule would affect three 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 adopted 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 adopted limit is consistent with retrofit limits for lean-burn engines in several other serious and above ozone nonattainment areas.

The adopted 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 adopted emission limits of §117.206(d) address pollutants which may increase as an incidental result of compliance with the adopted NO_x limits. The adopted 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 adopted ammonia limit of ten ppm is lower than the existing limit of §117.205(g). The adopted 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 NESCAUM. It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission is not including these related pollutant limits in the attainment demonstration SIP, in order to simplify the approval process for alternative emission specification under §107.221. This step will eliminate the need for case-specific SIP revisions to complete the approval of an alternate CO or ammonia limit.

The adopted §117.206(e) allows the same compliance flexibility given to ICI sources under NO_x RACT to be given to ICI sources under the adopted attainment demonstration emission specifications. The commission is allowing 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. Therefore, plant-wide emission averaging is worth maintaining because of its economic benefits.

The adopted exemptions in §117.206(f) are consistent with the NO_x RACT exemptions in §117.205(h), except for the adopted 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 from the adopted revisions 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 regulation of these sources less reasonable.

The adopted 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 adopted change to §117.207(g)(4) and (h)(3) would not allow a higher NO_x limit with hydrogen fuel. This adopted revision, which is only relevant in BPA with its major source refineries and petrochemical plants, is necessary to achieve the reductions adopted for the attainment demonstration SIP for BPA. Adopted 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 no longer include the boilers and heaters rated between 40 and 100 MMBtu/hr which are subject to the adopted new attainment demonstration emission specifications. The adopted revisions to §117.207(f)(3) and (g) and new §117.207(i) 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.

Adopted changes to §117.208, concerning Operating Requirements, and §117.209, concerning Initial Control Plan Procedures, change or eliminate cross-references to update to the newly named sections. The adopted 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 adopted revisions to §117.209, concerning Initial Control Plan Procedures, would update the section to accommodate the revised names of sections. The commission does not repeal §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.

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

The adopted change to §117.213(a)(2) provide an alternative certification procedure for stack exhaust flow meters installed as an alternative to fuel flow meters. The 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 adopted new §117.213(c)(1)(C) requires units which are tied into a common stack to be monitored with a NO_x continuous emission monitoring system (CEMS) or periodic emission monitoring system, if the heat input from all the units combined exceeds 250 MMBtu/hr. The adopted requirement provides additional NO_x monitoring that is equally effective as the monitoring currently required for boilers individually rated more than 250 MMBtu/hr. The adopted 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 adopted change to §117.213(e)(2) clarifies that the diluent monitor isn’t necessary if an exhaust flow monitor is used. The adopted 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 adopted changes to §117.215, concerning Final Control Plan Procedures, update the section to reflect the new names of the rule division and cross-referenced sections.

The adopted 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 adopted requirements are parallel to existing requirements in §117.215.

The adopted 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 new names of cross-referenced sections. An additional adopted change to §117.217 divides the section into subsections to make the text less dense and more readable.

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

The adopted changes to §117.223(a) and (k), concerning Source Cap, update the subsections to reflect the new names of cross-referenced sections and add a cross-reference in §117.223(a) to the adopted new emission specifications of §117.206 to allow the source cap to be used as an alternative means of compliance for these limits. The adopted 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 adopted 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 adopted changes to §117.223(g) make the subsection applicable only to early shut down credits used for NO_x RACT compliance. Section 117.223(g)(6), which was added in the previous rulemaking (Phase I) for lean-burn engines in BPA, is 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 adopted attainment demonstration emission specifications of §117.206. To accommodate new §117.223(h), existing §117.223(h)-(j) is relettered §117.223(i)-(k). Existing §117.223(k), added in the previous rulemaking for lean-burn engines in BPA, is deleted since the requirements are included in the revised §117.223(b).

An adopted 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, adopted concurrently in a separate section of this issue of the *Texas Register*.

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

The commission is adopting a staged schedule for compliance with the new BPA and DFW emission specifications for electric utility boilers, consistent with the adopted compliance schedule for ICI boilers and heaters in BPA. This makes the schedule consistent for all sources in BPA affected by the new emission limits. For the electric utility boilers in DFW, the adopted 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) are required by May 1, 2003. The final one-third of the reductions is required by May 1, 2005. Although there are fewer utility units in DFW affected by new emission specifications than ICI units in BPA, the DFW utility sources are required to make much larger reductions, necessitating a combination of combustion and flue gas cleanup controls on many units.

An adopted change to §117.520, concerning Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources, renames the section title to "Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas," to distinguish this section from the adopted section applicable to ICI sources in a regional area, published in a separate location of this issue of the *Texas Register*. The adopted changes to §117.520(a) for sources in BPA, and §117.520(b) for sources in DFW, create separate paragraphs in each subsection addressing compliance schedules for the NO_x RACT rules and the adopted emission specifications for attainment demonstrations. The commission is adopting a staged compliance schedule for the 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 adopting a compliance date of March 31, 2002 for the ICI sources in DFW, which allows two years for implementation of the control measures in DFW. In contrast to the adopted emission limits in BPA, the adopted 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.

Adopted changes to §117.570, concerning Trading, update the section to reflect the new names of cross-referenced sections and add cross-references to the 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 adopted 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 revised definitions used in §117.223. In order to specify the heat input calculation for utility sources using trading for compliance with the emission specifications for attainment demonstrations, the heat input terms, H_j in §117.570(b)(2), and H_i and H_{Mi} in §117.570(c)(1), are referenced to §117.108(c). 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 the new requirements for trading for compliance with the attainment demonstration emission specifications. The adopted 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(c)(2), similar revisions are adopted 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 deleted since the requirements are included in the adopted §117.570(b).

The commission repeals §117.601, concerning Gas-Fired Steam Generation, because the §117.601 requirements are now 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, published in a separate section of this issue of the *Texas Register*.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the 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 adopted 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. Specifically, the emission limitations within this rulemaking were developed in order to meet the NAAQS for ozone set by EPA under FCAA, §109, and therefore meet a federal requirement. States are primarily responsible for ensuring attainment and maintenance of the NAAQS once EPA has established them. FCAA, 42 USC §7410 requires states to submit SIPs which contain enforceable measures to achieve the NAAQS. The adopted rules, which reduce ambient NO_x and ozone in BPA, are being submitted to EPA as one of several measures of the required new attainment demonstrations. These rules 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, 42 USC §7511a(f) requires any moderate, serious, severe, or extreme ozone nonattainment area to implement NO_x RACT. The adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIPs for BPA and DFW, required by FCAA, 42 USC §7410. There is no contract or delegation agreement that covers the topic that is the subject of this rulemaking. Therefore, these adopted 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 changes are not adopted solely under the general rulemaking authority of the commission but are adopted to comply with the requirements of federal regulations.

In addition, the legislative history contradicts the comment that a full RIA is required of this rule. The requirement to provide a fiscal analysis of proposed regulations in the Texas Government Code was amended by SB 633 during the 75th Legislative Session. The intent of SB 633 was to require agencies to conduct a regulatory impact analysis of extraordinary rules. These are identified in the statutory language as major environmental rules that will have a material adverse impact and will exceed a requirement of state or federal law, a delegated federal program or is adopted solely under the general powers of the agency. With the understanding that this requirement would seldom apply, the commission provided a cost estimate for SB 633 that concluded "based on an assessment of rules adopted by the agency in the past, it is not anticipated that the bill will have significant fiscal implications for the agency due to its limited application." The commission also noted that the number of rules that would require assessment under the provisions of the bill was not large. This conclusion was based, in part, on the criteria set forth in the bill that exempted proposed rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law. States must develop programs for each nonattainment area to ensure that area will meet the attainment deadlines and because of the ongoing need to address nonattainment issues, the commission routinely adopts SIP rules. The legislature is presumed to understand this federal scheme. If each rule proposed for inclusion in the SIP was considered to be a major environmental rule that exceeds federal law, then every SIP rule would require the full regulatory impact analysis contemplated by SB 633. This conclusion is inconsistent with the conclusions reached by the commission in its cost estimate and by the Legislative Budget Board (LBB) in its fiscal notes. Since the legislature is presumed to understand the fiscal impacts of the bills it passes, and that presumption is based on information provided by state agencies and the LBB, the commission believes that the intent of SB 633 was to only require the full regulatory impact analysis for rules that are extraordinary in nature. While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of the FCAA. Although the commission has determined that this is a major environmental rule because it may adversely impact in a material way a sector of the economy, these reasons support the conclusion that, the rules adopted for inclusion in the SIP fall under the exception in §2001.0225(a) because they are specifically required by federal law.

Comments received during the comment period regarding the draft regulatory impact analysis are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

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. As 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 fulfill an obligation mandated by federal law. The adopted amendments will implement requirements of 42 USC §7410. 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 requires 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 adopted 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 will be submitted to EPA under these requirements.

PUBLIC UTILITY REGULATORY ACT DETERMINATION

As described earlier in this preamble, the commission adopts these revisions to Chapter 117 and the SIP in order to reduce NO_x emissions and demonstrate attainment in the DFW and BPA ozone nonattainment areas. Accordingly, the commission makes the following determination, as required by the Public Utility Regulatory Act (PURA), Texas Utilities Code (TUC), §39.263(c)(1)(A) and

§39.263(c)(3): reductions of NO_x made in compliance with this rulemaking are hereby determined to be an essential component in achieving compliance with the NAAQS for ground-level ozone; and the amount and location of reductions of NO_x emissions resulting from this rulemaking are hereby determined to be consistent with the air quality goals and policies of the commission.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMITS PROGRAM

Since 30 TAC Chapter 117 is an applicable requirement under 30 TAC Chapter 122, owners or operators subject to the Federal Operating Permit Program must, consistent with the revision process in Chapter 122, revise their operating permit to include the revised Chapter 117 requirements for each emission unit affected by the revisions to Chapter 117 at their site.

HEARINGS AND COMMENTERS

Public hearings on this proposal were held on January 24, 2000 in El Paso; on January 25, 2000 in Austin; on January 26, 2000 in Longview; on January 27, 2000 in Dallas and Lewisville; on January 31, 2000 in Beaumont and Houston; and on February 9, 2000 in Denton. The comment period initially was to close on February 1, 2000, but was extended until February 14, 2000 (see the January 21, 2000 issue of the *Texas Register* (25 TexReg 461)).

Six hundred twelve commenters submitted testimony on this proposal. The following organizations and companies submitted comments jointly: The Dallas and Forth Worth Chapters of the Sierra Club, Downwinders At Risk, Sustainable Economic and Environmental Development, Texas Campaign for the Environment, Texas Clean Water Action, and Texas Public Citizen, referred to here as Citizens (filed *Citizen's Implementation Plan for Cleaner Air in DFW (January 2000)*); the Environmental

Defense and the Texas Air Crisis Campaign on the DFW SIP of the TNRCC (the latter comprising 44 participating neighborhood, consumer, or environmental groups), referred to here as the Air Campaign; the City of Denton and the City of Garland (Denton/Garland); and The Senior Citizens Alliance of Tarrant County (SCATC) and the Senior Political Action Committee (SPAC).

Most commenters generally supported the proposed revisions, but the commenters required to reduce emissions by the proposed rules either opposed the rules or recommended revisions. The following commenters generally supported the proposed revisions: 593 individuals; Air Campaign; American Lung Association (Dallas and Texas Chapters); Citizens for a Safe Environment; Citizens; Clean Air and Water, Incorporated; Green Party of Tarrant County; League of Women Voters (Dallas, Tarrant County, and Texas Chapters); NAACP Environmental Justice Program, Port Arthur area; People Against a Contaminated Environment; SCATC/SPAC; Sierra Club (Dallas, Greater Fort Worth, and Lone Star Chapters); and the Tarrant Coalition for Environmental Awareness. The following commenters generally opposed the proposed revisions: Coalition of Jefferson County Chambers of Commerce (consisting of the Beaumont, Port Neches, Nederland, Port Arthur, and Groves Chambers of Commerce); Equistar Chemicals, Port Arthur and Beaumont Facilities; Southeast Texas Regional Planning Commission Air Quality Advisory Committee (SETRPC); an individual; and State District 20 Representative Zeb Zbranek. The following commenters generally opposed the proposed revisions but suggested changes: Beaumont Methanol Limited Partnership, a Terra Industries Business (Beaumont Methanol); Entergy Gulf States, Incorporated (Entergy); and Inland Paperboard and Packaging, Incorporated (Inland). The following commenters generally supported the proposed revisions but suggested changes or clarifications: American Lung Association of Texas (ALAT); City of Cleburne (Cleburne); City of Dallas (Dallas); Denton and Garland; Environmental Defense (ED); EPA;

Lockheed Martin Aeronautics Company (Lockheed); North Texas Clean Air Steering Committee (Steering Committee); Public Utility Commission of Texas (PUC); Reliant Energy (Reliant); Southeast Texas Plant Managers Forum (SETPMF); Texas Chemical Council (TCC); Texas Industry Project, via Baker & Botts, L.L.P. (TIP); and TXU Electric Company (TXU). ALAT Dallas Chapter, Citizens for a Safe Environment, League of Women Voters of Dallas, Lone Star Sierra Club, and 184 individuals supported Citizens. BP Amoco supported the comments of TCC. Beaumont Methanol, Entergy, Equistar, and Inland endorsed the comments of SETRPC.

ANALYSIS OF TESTIMONY

Beaumont Methanol, Entergy, Equistar, Inland, SETPMF, and SETRPC said that the air quality modeling did not support the level of emission reductions proposed for BPA. Beaumont Methanol and Equistar said that the resulting reductions are superfluous, based on scientific evidence and EPA guidance.

The ozone exceedances that were selected for analysis in the BPA ozone attainment SIP occurred over a period between August 31 and September 11, 1993. This period can be separated into two regimes. First, between August 31 and September 2, monitor data indicates that there was enough ozone blown into the area to cause exceedances without local BPA contribution. Later, between September 8-11, winds were relatively stagnant and the exceedances have a higher relative proportion of locally generated ozone. The commenters have focused on the effects of transport on BPA's attainment status. The EPA, in written statements on what is required for an approvable attainment demonstration for BPA, has focused on the benefits of local controls during the more local episode. The benefits of the adopted rules are readily apparent during this

period. The air quality modeling shows that the NO_x reductions resulting from the adopted rules will be effective in reducing ozone in BPA. The adopted rules, representing Tier I control measures, provide an additional 16 parts per billion (ppb) of ozone reduction, from 146 to 132 ppb for September 10th of the modeled episode. The air quality modeling of the more locally generated ozone exceedances clearly supports the adopted rules.

The science of ozone controls shows that reductions of ozone precursors over a regional area are necessary for attainment in BPA, DFW, and HGA. Analysis of wind back trajectories of ozone exceedance days in the HGA area show that the wind has come from BPA during some of these days.

SETRPC asserted that by using a November 1999 EPA gap-filling estimation technique, control levels of 5b would not be sufficient, but that the 5b1 scenario would result in superfluous controls. Equistar asserted a reduction in the range of 8-11 tons per day of NO_x reductions versus the proposed 40 tons per day may be all that is needed to bring BPA into attainment after backing out the transport from HGA, while Inland suggested the modeling indicates that 8.1 tons per day would be sufficient. Beaumont Methanol said that the proposed rules will be costly and onerous.

The 5b control level represents previously adopted measures including the lean-burn engine RACT rules and are evidently the basis for Equistar and Inland's comments. The commission is submitting an attainment demonstration to EPA which does not rely on the deterministic modeling predicting ozone below 125 ppb. Although the adopted measures are effective, the model does not predict attainment on September 10. EPA's policy allows for such a demonstration with the use

of weight of evidence (WOE). In order to use this policy, EPA has stated firmly that the modeling should be conducted using all practical or reasonable control measures before a WOE analysis is employed. The adopted measures, which are based on combustion modifications, rather than more difficult flue gas clean up controls, are both practical and reasonable in comparison to measures required of similar areas in the nation. Demonstration always begins with the deterministic test: are all modeled grid cells < 125 ppb? When this condition is not met, States must explore WOE analyses. With WOE, the further that the modeled demonstration is from 125 ppb, the more analyses that are required. As part of the commission's attainment demonstration for BPA, the agency has used the Future Design Value/Relative Reduction Factor technique as its WOE technique. After releasing the proposed SIP for public comment, the commission has been informed by EPA that this proposed WOE is not sufficient to demonstrate that attainment can be expected by 2007. The commission will be submitting additional analyses to shore up its WOE. It would not seem reasonable to substitute a different single alternative WOE approach, such as SETRPC's gap-filling analysis, that allows for less reductions when EPA has already indicated that the commission's current approach is not sufficient.

SETRPC stated that according to its WOE analyses, 5b1 is superfluous and the DVF done for 5b shows future design values below 125 ppb. They indicate that EPA's WOE approach/policy is difficult to pin down and sometimes contradictory. They referenced EPA's November 1999 guidance for identifying additional reductions by not modeling ("gap-filling") and how it should be applied instead of the current future design value approach.

The deterministic test is modeling all cells below 125 ppb. If this is not met, additional analyses must be used to sway the reviewing authority (EPA in this case) that attainment may still be expected, despite what the modeling indicates. A WOE/DVF analysis that shows BPA's future design value to be 124 ppb, e.g., would not carry nearly as much weight as one that predicts 116 ppb. In addition, the commission's understanding of EPA's November 1999 guidance is that it is a mechanism for helping areas that have modeling large suites of controls, yet still are short of attainment. BPA does not fall in that category. Additional input from EPA indicates that the techniques outlined in the November 1999 gap-filling guidance may be used if conventionally calculated future design values are greater than 125 at one or more monitors, but the technique may not be used to estimate additional reductions, not modeled.

SETRPC questioned some of the commission's analysis of locally-generated versus transport episodes. They noted that if not for transport, BPA would not be nonattainment, since the area does not produce enough ozone.

The FCAA does not provide for cases of "attainment but for transport." However, EPA's transport policy does give nonattainment areas that are impacted by transport a mechanism for reaching attainment without the same level of burden required of more serious upwind areas.

SETRPC commented that for the BPA modeling, HGA is not in modeled attainment. They asserted that if HGA were at attainment, modeling would show that BPA would be in attainment, and the additional NO_x rules in BPA would not be needed.

The emission reductions necessary for the attainment demonstration in HGA will go far beyond those required for BPA. Even so, after all identifiable practicable measures have been modeled in HGA, this deterministic modeling may still not show attainment in HGA. The strategy recommended by SETRPC is not practical for attainment in either BPA or HGA. It must be recognized that NO_x reductions made in each area will contribute to attainment in both areas and that a given amount of NO_x reduced in BPA will be more effective for attainment in BPA than the same amount reduced in HGA.

SETRPC had MCNC redo performance statistics where monitoring sites were eliminated on three days of the September episode (September 8, 9, and 11) in order to show that model performance on September 10 might actually be suspect. SETRPC's thesis was that since model performance was only acceptable on September 10, and on this day, the ozone cloud was mostly offshore, away from monitors, that the acceptable performance is somehow suspect. Therefore, they conclude, this episode should not have been used for control strategy development.

This is a hypothetical exercise that could also have been played the other way. That is, if enough sites were eliminated from the September 8 day, it would have had acceptable performance and then it might have become the controlling day and would have meant greater reductions. Even if the commission agreed that the September 8-11 was not appropriate, it does not mean that the commission would not have to model a locally-generated episode. Given time-constraints, a different home-grown episode could probably not been developed in time to meet EPA's deadlines, and BPA would certainly face bump-up.

SETPMF questioned if there has been consistent application of bias correction in all the modeling demonstrations for the major nonattainment areas of DFW, HGA, and BPA. SETRPC asserted that if the commission had bias adjusted the modeling results, the proposed NO_x rules would not be needed.

The commission staff used a bias correction procedure during the course of evaluating candidate control strategies in DFW. The procedure is not supported by EPA for making an attainment demonstration and the commission did not use it as part of the modeling or WOE analysis for any DFW, HGA, or BPA final SIP submission.

SETRPC stated that BPA is being held to a stricter standard than St. Louis, which is also a moderate nonattainment area. In particular, St. Louis RACT requirements are much less than BPA, although St. Louis has 65% more point source NO_x.

The commission disagrees that the BPA area is being held to a stricter standard than St. Louis. The St. Louis inventory contains a greater proportion of mobile source emissions due to its greater population. Missouri has developed a SIP which includes difficult but necessary measures such as centralized IM240 auto inspections to address mobile source emissions and reformulated gasoline requirements. Coal-fired utility boilers account for most of the stationary source NO_x in the St. Louis area and the 70-80% NO_x reductions mandated by the EPA NO_x SIP call limit of 0.15 lb NO_x/MMBtu are actually more stringent in terms of the depth of reduction and costs than the corresponding limits for boilers in BPA. Although Missouri is still trying to reduce the required reduction level, the resulting reductions would be very similar to the estimated 58% boiler NO_x

reductions of the adopted Chapter 117 limits. Because the BPA boilers are gas-fired, whereas the St. Louis boilers are coal-fired, the control costs will be lower for BPA than for St. Louis.

The St. Louis SIP also includes these WOE elements: emission trends, air quality trends, relative reduction factors, and analysis of reduction in pervasiveness, frequency and intensity of modeled ozone. The commission is submitting the same level of WOE for Beaumont.

EPA supported the proposed emission standards for BPA. They said it was evident that local pollution sources on many days are the major contributors to the ozone problem in southeast Texas and that the combination of the proposed rules and other regional efforts should help the area meet the one-hour ozone standard. They said that environmental groups have notified EPA of their intent to sue EPA for not bumping up areas to the next classification and that this scrutiny underscores the need to have a strong plan in place. TCC expressed appreciation for the efforts made by the commission toward extending the attainment date of BPA to 2007 and preventing the area from being reclassified as a serious ozone nonattainment area. They noted, nonetheless, that the proposed control scenarios include smaller emitting sources and even lower emission limits than were proposed by industry representatives.

The commission acknowledges the support for its efforts in extending the attainment date for BPA. The commission believes that the adopted limits represent both effective and reasonable measures for the industrial point sources in BPA. The limits are consistent with combustion based controls, which are recognized as being cost-effective. The application of the emission limits to intermediate size heaters and boilers broadens the Chapter 117 NO_x reduction requirements to

several major NO_x sources in BPA, resulting in a greater sharing of the burden of achieving compliance with the air quality standards. Although regionally transported ozone into BPA forms the basis for the extension of BPA's attainment date, it must also be recognized that the reductions that BPA makes will improve not only the air quality in BPA, but will also reduce the ozone transported out of BPA. The reductions in regionally transported ozone and its precursors are essential for HGA and DFW to attain the one-hour ozone standard.

The PUC fully supported the TNRCC's efforts to clean up Texas's air. They urged the commission to be creative in developing solutions to the related problems of air quality and meeting the electric needs of customers in the DFW area over the next five to ten years. The PUC attached a summary of the ISO report on the reliability problems of the DFW electricity transmission system which identified additional options beyond improving the transmission system. These options include: adopting PUC rules that would make it feasible for owners to retrofit existing facilities; installing new generation in the area; and reducing the growth of load in the area. The PUC also urged the commission to consider whether a comprehensive trading program for NO_x for the DFW area would be beneficial.

The commission appreciates the PUC's support of the goal of cleaning up Texas' air. The commission is committed to incorporating maximum flexibility for the electric industry in achieving this goal. The adopted rules allow emission trading among different source owners as a compliance option. The commission has directed staff to expeditiously develop a more comprehensive NO_x trading program to expand the number of SIP rules which could be complied with by NO_x trading. As discussed in more detail in the ANALYSIS OF TESTIMONY portion of this preamble, the adopted emission standards include adjustments which largely maintain the

intended level of NO_x emission reduction from DFW electric utilities, but increase the feasibility for owners to retrofit existing facilities if replacement of generation or new transmission capacity is unavailable in time for rule compliance. As discussed in the next response, there is emission control technology available that would allow new generation to be built in the area.

Citizens, the Air Campaign, and 192 individuals recommended early retirement of the oldest and dirtiest grandfathered utility plants. The EDF and Air Campaign said that an alternative way to achieve even greater reductions than 88% is by retiring older, highly polluting generating facilities and replacing them with ultra-low emissions, natural gas combined cycle combustion turbines or zero-emissions renewable energy resources. They said the difference between the retrofit strategy and the retirement/replacement strategy may be as much as ten tons per day on average and even greater during the ozone season. They said the retirement strategy could provide 95% or more reductions from the electric utility sector.

The commission agrees that retiring older facilities and replacing them with highly efficient, ultra-low emission gas turbines is an effective strategy for reducing emissions. These new plants may be encouraged by regulatory policy but are too costly to be mandated; the decision to build them should originate in the private sector which is in a better position to determine whether they are economically justified. It is important to note that the commission's adopted rules allow compliance through a system cap, which enables a retirement and replacement strategy to be used to reduce emissions from the existing utility boilers.

The commission agrees that retirement and replacement could ultimately be used to achieve a further reduction approaching ten tons per day NO_x from electric generation in the DFW area, but it is unrealistic to expect this outcome could be achieved within the five-year compliance time frame mandated by the FCAA. Such a strategy would require replacing most of the existing 5,735 MW of utility boiler capacity in DFW with ultra low emissions equipment. The capital expenditure required to replace this existing infrastructure would be significant. The DFW utility boilers are used mostly to fulfill the need for short term power during the late afternoon summertime peaks, which translates to low annual activity levels. Low activity factors increase the capital recovery period, which slows investment. The need for assured reliability also impedes installing the newest, most efficient gas turbines available, because established equipment performance provides lenders and utilities the assurance of high reliability they seek before committing their capital. Nonetheless, a further ten tons per day reduction from the adopted DFW limits of 18 tons per day could be achieved if about 4,000 MW of existing boiler capacity were replaced with gas turbines using ultra-low emissions technology. Two types of lowest achievable emission rate (LAER) technology have recently been demonstrated in service on three gas turbines permitted between 2.0-2.5 ppm NO_x at 15% O_2. The two ppm limit represents a reduction of 7/9, or 78%, from a starting point equal to the Chapter 117 emission limit of 0.033 lb NO_x/MMBtu (the rate 0.033 lb NO_x/MMBtu corresponds to gas turbine emissions of 9 ppmv at 15% O_2). One technology is a catalytic combustor which reduces the formation of NO_x and the other is a catalytic bed exhaust treatment process. The exhaust cleanup LAER technology is operating at 0.5 ppm NO_x on one of the turbines. As practical matters, the technologies are not currently operating on gas turbines above 100 MW, and lenders and utilities also seek assurance of high reliability from the control equipment (often in the form of demonstrated operating hours)

before committing capital. The catalytic combustor requires redesign of each type of turbine combustor. The exhaust cleanup LAER technology costs more than the BACT technologies which may be used outside the four-county DFW area, a further disincentive to wholesale replacement of the utility boilers in DFW. In summary, it is not realistic to expect the DFW utility NO_x emissions could be reduced a further ten tons per day within the compliance time frames by installing natural gas combined cycle turbines with ultra low emissions.

Lockheed and TCC expressed concern with increased storage and transport of anhydrous ammonia posing additional safety concerns. Lockheed said that NO_x emissions are best controlled using advanced burner controls. Requiring reductions with SCR introduces new risks at regulated facilities as well as communities adjacent to the regulated facilities. The risks come from transporting ammonia through the adjacent community as well as handling and storage mishaps. The risks associated with ammonia every day of the year may offset any benefit to the public of reducing NO_x emissions with SCR during an ozone day.

The commission's rules do not dictate the choice of NO_x control technologies and the available technologies continue to develop rapidly. Whether a given method of control is best is a value judgement which, if made, should at least be based on the needed reductions and the specific source to be controlled. The emission limits for the DFW utilities will probably necessitate use of some SCR, which requires injection of a reagent. For the industrial sources, there are several demonstrated control technologies which can achieve the NO_x limits without reagent injection. The risks associated with anhydrous ammonia concern its asphxyiant and moderate combustibility properties. It is not classified as a hazardous air pollutant chemical and is lighter than air so it

dissipates readily. It is routinely handled by farmers and used in many industrial applications throughout the country. However, its asphyxiant and combustibility properties cannot be taken lightly. As Lockheed stated, ammonia transport, storage, and handling are regulated for safety under various safety programs such as the Accidental Chemical Release Risk Management Program in order to minimize risks. Several alternatives to transporting and storing anhydrous ammonia are available. Systems are available which convert solid urea to ammonia on a continuous, as-needed basis. Solid urea is not volatile or combustible like ammonia. These systems avoid whatever risks may be associated with the transport and storage of anhydrous ammonia. Another approach, that New Jersey follows, is to limit the quantity of anhydrous ammonia that may be stored, allowing a water solution with a maximum ammonia concentration of 26%, which reduces or eliminates concerns about accidental releases.

Cleburne, TCC, TXU, and the Steering Committee recommended seasonal or episodic NO_x controls to reduce operating costs. TXU said ozone in DFW is very seasonal (May 1 through October 31). TCC listed additional advantages of reduced ammonia handling, reduced subsequent emissions of particulates, and allowing facilities to schedule planned outages more efficiently. TXU mentioned reduced operational, recordkeeping, and financial burdens for both industry and the commission. TXU also cited consistency with the construction equipment operating restrictions which were proposed to apply between June 1 and October 31. TCC said that if NO_x controls were required only during the ozone season, industry would have the option of continuing to run the NO_x controls to generate discrete emission reduction credits (DERCS).

The commission agrees that ozone in DFW is very seasonal. The issue of ozone season only controls is complicated by the varying length of the ozone season between DFW and BPA/HGA and also involves air quality considerations beyond ozone. The season for the one-hour ozone standard in DFW has been defined by EPA policy by the monitoring period in 40 CFR Part 58, Appendix D and by commission rule in §101.29(a)(19) of this title, relating to General Air Quality Rules, as an eight-month period from March 1 through October 31. For the eight-hour ozone standard, the ozone season tends to be longer in Texas. EPA set an 11-month ozone monitoring season for DFW for the eight-hour standard (EPA-454/R-98-001, June 1998). Although the data provided by TU shows that over the last ten years, the exceedances of the one-hour standard have been limited to the five months of June-October, there are ozone and other environmental benefits to year-long NO_x RACT control in DFW. At times, regional transport moves DFW NO_x southerly into areas with more of a year-long potential for ozone exceedances. Year-long controls will help in preventing current near-nonattainment areas from becoming nonattainment under the eight-hour ozone standard. Locally, year-long controls will reduce nitrates in the winter season. Nitrates contribute to the winter visibility impairment in DFW sometimes called the white or brown cloud. In addition, NO_x adds to the nitrification of surface waters, an adverse ecological impact which at times may contribute to algae buildup and related problems.

Weighed against the potential loss of ozone and other environmental benefits are any reductions in costs and effort that seasonal NO_x controls would offer. In contrast to the existing NO_x RACT standards of Chapter 117, which require an emission limit on each utility boiler, the system cap is a new feature of Chapter 117 which adds flexibility by reducing compliance efforts necessary on a single boiler to maintain continuous emission compliance. This flexibility is especially useful in the

off-peak seasons when oil firing and boiler maintenance activities are scheduled. The effects of any increased emissions from these activities on one boiler are spread over the entire system and become of little consequence. The burden of recordkeeping for eight months as opposed to 12 months does not seem significant because the system cap tracking systems to be practical must be automated. Once set up, it is arguably as burdensome to turn an information gathering system on and off than to use it continuously. The system cap also will enable operating cost savings to accrue in a similar manner as seasonal limits. A combination of combustion modifications and SCR controls will be used to comply with the adopted emission limits for DFW utilities. Low-NO_x burner combustion modifications can not be turned off, so there is little opportunity to reduce operating costs from these combustion modifications. In contrast, SCR involves significant operating expense from ammonia consumption. The primary benefit to TXU of an eight-month compliance season would be reduced compliance cost due to reduced ammonia consumption. Capital costs must be incurred regardless of the length of the compliance season. It is evident that the system cap will enable cost savings to accrue from reduced SCR utilization rates during much of the year. TXU's historical, 1996-1998 annual average rate in DFW was 43 tons per day. The third quarter average was 78.5 tons per day. Therefore, during the other three quarters, average emissions were 31 tons per day. This means that during three quarters of the year, the adopted rule, which allows TXU to emit an average 13.8 tons per day of NO_x, requires a 56% reduction of NO_x emissions from the relatively uncontrolled 1996-1998 levels. During the lowest utilization months, the required reductions will be even less. SCR utilization required to achieve compliance under average non-third quarter conditions will be sparing. The adopted system cap effectively operates as an episodic rule, as recommended by TXU and the Steering Committee. The

documented issues of regional transport of ozone and the visibility problem in DFW in the winter justify maintaining the restrictions on an annual basis.

In response to TCC's comment on reduced ammonia emissions as a benefit of seasonal rules, the sparing usage of SCR under average conditions will reduce any ammonia emissions. As discussed in the response to the comments on the ammonia limit, ammonia slip emissions (and therefore subsequent particulate formation) in any case will be small in comparison to other existing sources of ammonia.

In response to TXU's comment that the construction shift requirement is seasonal, the commission believes that because the shift rule does not create additional environmental benefits from reduced emissions and has a relatively high impact on social behavior, the difference in the applicability of the two rules is well justified. The commission disagrees with TCC that seasonal NO_x controls would or should allow a source to build up DERCs during the offseason. The DERC trading program is designed to facilitate the goal of reducing ozone forming emissions and to generate credits in the offseason for use during the ozone season when the rules apply would seem to circumvent that goal. The commission has made no change in response to these comments.

Reliant recommended that the exemption in §117.103(a)(2) for boilers with annual heat input below $2.2(10^{11})$ Btu per year be modified for clarity by allowing the exemption to be calculated on an average over the three most recent calendar years.

The existing exemption, which applies to the existing RACT requirements as well as the newly adopted BPA and DFW attainment demonstration emission specifications, is stated as a per year limit, so the recommended change is not simply a clarification. The change would relax the rule because the annual heat input of the utility peaking boilers in the three nonattainment areas varies significantly from year to year. An exemption based on a three-year average would make it easier for some boilers to escape regulation. This paragraph was not identified for change in the rule proposal, nor was this approach analyzed in the SIP proposal modeling for DFW. The commission believes it would be more appropriate to evaluate this recommendation for the next Chapter 117 rule proposal, allowing notice and comment on such a change. The commission has made no change in response to this comment.

TXU commented that natural gas curtailments can create reliability problems, and when backup fuel oil must be fired, the NO_x controls are not as effective. They recommended an exemption for oil burning during emergency electrical shortage conditions declared by ERCOT. They also recommended that emergency oil burning and testing of emergency oil burning equipment during the non-ozone season be excluded from inclusion in the annual cap, if the commission establishes such a cap.

The commission agrees that natural gas curtailments can create reliability problems, but notes that reliability of the natural gas supply is not affected by the NO_x emission limits. As TXU stated, gas curtailments are more commonly a cold weather issue. The system cap is less likely to be exceeded under gas curtailment conditions because the 30-day average winter peak electric demand is not as great as the summer 30-day peak demand. Nonetheless, the system cap limit has been designed on the premise of gas fuel operation and extensive oil firing due to an emergency

condition could cause exceedances of the cap. Existing §117.103(b) contains an exemption from the oil-fired RACT emission limits during ERCOT declared emergency conditions which necessitate oil firing. There is no oil-fired emission limit in the newly adopted emission limits, which makes it awkward to extend the existing exemption without proposing new rule language. The commission intends to propose an exemption for emergency oil firing applicable to each affected area in the next round of Chapter 117 revisions for the HGA attainment demonstration, anticipated to be proposed in July, 2000. The commission has made no changes in response to this comment.

TXU recommended that the commission add language in the rule stating that the RACT limits for a unit expire on the applicable compliance date of the new SIP rule for that unit. They said this will eliminate unnecessary reporting and avoid any potential conflicts of a RACT limit and the new more stringent limits.

The commission agrees with the TXU that it would be beneficial that the more stringent attainment demonstration emission limit supersedes the RACT limit in each affected area on the applicable compliance date. The most appropriate place to locate this statement is with the NO_x RACT limit in §117.105. The commission has made no change in response to this comment, but plans to open this section to address the comment in conjunction with upcoming rulemaking for the HGA attainment demonstration this summer.

In §117.105(h) and §117.106(c)(1), Reliant recommended that the CO limit be expressed in lb/MMBtu because they use CEMS that measure and record pollutants on a wet basis. They said, in addition, many CEMS use carbon dioxide as the diluent to correct pollutants to a lb/MMBtu basis. The proposed clarification would necessitate the complete replacement of the CEMS on numerous electric generating units that use wet-basis instrumentation to demonstrate compliance with the CO limit of §117.105(h). Specifying the limit alternatively as 0.3 lb CO/MMBtu preserves the viability of wet-basis CEMS.

The commission agrees with Reliant that allowing compliance in two formats is more convenient and has revised the adopted CO limit in §117.105(h) and §117.106(c)(1) to include a 0.30 lb/MMBtu equivalent limit.

In §117.106(a), Entergy said that the proposed 0.10 lb NO_x/MMBtu emission limit was unnecessarily stringent and recommended a limit of 0.156 lb NO_x/MMBtu. They said this was more in line with sound science as applied to the SIP development for BPA. Entergy recommended a 30-day rolling average in §117.106 instead of a 24-hour average. Entergy expressed concern that the proposed utility emission limit for BPA could require flue gas cleanup controls.

As discussed in the SIP analysis and the response to the WOE analysis provided by SETRPC, the commission believes that the NO_x reductions identified in the adopted SIP are necessary for ozone attainment and are in line with sound science. The utility limit is part of a larger control package that is designed to provide the reductions identified in the SIP. The emission limit was developed by considering the full set of major point sources in BPA and developing a point source reduction package with cost-effectiveness in mind. Although the total package of Chapter 117 NO_x measures is expected to reduce point source NO_x by 40% from 1997 levels, the unit specific reductions to achieve this result vary from no required reductions on certain difficult-to-control sources, to 70-

80% reduction for IC engines. Some sources have been required to make greater than 40% reductions in order for other sources to forego more expensive reductions to achieve less. The capabilities of combustion modifications and cost-effectiveness were used to design the limits, not a uniform percent reduction from all equipment. The combustion modifications required of Entergy are expected to be cost effective relative to the other sources required to reduce emissions under Chapter 117. The commission agrees that the proposed reduction of 0.10 lb/MMBtu would represent a 62% reduction as calculated from the allowable 24-hour RACT emission limit. However, the system cap 30-day average limit represents only a 50% reduction from the allowable 30-day average RACT emission limit of 0.2 lb/MMBtu. Viewed in terms of reductions from the existing RACT limits, compliance with the individual unit rate limit is a little more stringent than the 30-day system cap. However, cap compliance assures that mass emissions will not increase due to activity level increases. Finally, the BPA electric utility boiler limit was influenced by the fact that the five boilers that Entergy operates in BPA have not required installation of emission controls (with the exception of combustion tuning) to comply with the RACT limits, so combustion modification technologies such as low-NO_x burners and FGR are still available to reduce emissions. As described in the cost note of the rule proposal, combustion modifications are achieving emissions of 0.05 lb NO_x/MMBtu, annual average on similar tangential-fired boilers, so even with somewhat shorter 30 day or daily limits, SCR is not likely to be selected to comply with the adopted 0.10 lb NO_x/MMBtu BPA utility emission limits. The commission has made no change in response to the comment.

Regarding §117.106(a), Entergy commented that EPA recently evaluated reasonable and practical control technology for retrofit of utility boilers and selected a standard of 0.15 lb/MMBtu for the NSPS and the OTAG SIP call. They noted that the recent NSPS is a 30-day rolling average limit, which represents a 25% reduction from the current Chapter 117 RACT rule. Entergy said, therefore, a 25% reduction has been found to be a reasonable limit, and one could extrapolate that a 62% reduction would be unreasonable for retrofit technologies.

The NSPS is a national, one size fits all rule, which had to factor in such units as the many high NO_x baseline coal units prevalent in the Midwest. For example, the NSPS requires an 80% reduction from a typical coal-fired boiler in Ohio, if the boiler is modified. In contrast, the adopted limits for the BPA utility boilers are designed specifically for the five gas-fired boilers operated in BPA. As discussed in the cost note of the proposed rule and the response to the previous comment, the commission believes that the adopted emission limits for BPA utility boilers are reasonable retrofit standards.

In §117.106, Entergy commented that the rolling 24-hour average emission limits resulted in 8,760 compliance periods a year, and recommended instead, a daily limit resulting in 365 compliance periods. TXU also recommended a daily limit.

The commission agrees that a calendar day limit is much easier to track and not particularly different in effect, and has revised the averaging times in §117.106 to specify a daily calendar average. Periods during which zero firing occurs are not included in the calculation.

Concerning §117.106(b), the proposed electric utility emission limit in DFW, the Air Campaign, American Lung Association (Dallas and Texas Chapters), Citizens, Citizens for a Safe Environment, Environmental Defense, Green Party of Tarrant County, League of Women Voters (Texas and Tarrant County Chapters), Senior Citizen's Alliance of Tarrant County and Senior Political Action Committee, Sierra Club (Dallas, Greater Fort Worth, and Lone Star Chapters), Tarrant Coalition for Environmental Awareness, and 593 individuals supported the proposed 88% reduction from power plants and other large NO_x sources in DFW. The American Lung Association Texas Chapter said the proposed 88% NO_x reduction in DFW and 90% reduction in HGA from grandfathered power plants may be the most effective measure in protecting public health and cleaning up the air in these two major cities. The Air Campaign said that the 88% utility reductions in DFW will almost certainly be needed in order for the DFW region to attain the ozone standard. Citizens and 184 individuals said that reductions from power plants are among the cheapest available and have a significant impact on ozone levels. Among the individuals who supported the 88% reduction, 399 said don't back down by opting to require a 70% cut. One individual reasoned that if the major utility is allowed to continue emitting at high levels there is no justification for other measures, because the utility emits far more than he. Another individual supported tough measures for the heavy industries that are polluting the air and expressed concern that the commission may bow to lobbyists and political pressure to either excuse or ignore these emissions. An individual said that BPA and DFW are legally severe areas and that they must have controls that severe areas deserve, a 90% NO_x reduction from all major point sources. The City of Cleburne supported a reduction of up to 88% in DFW. The City of Dallas supported DFW electric utility NO_x emission reductions of 70-88%. The City of Lewisville did not support the proposed 88% reduction, citing the additional cost of power to the consumer between a 70% and an 88% reduction. Corinth Mayor Spellerberg did not support industrial source reductions of up to 90%, similar to Los Angeles, because the DFW geography is not similar to the mountainous bowl of Los Angeles which traps pollution. Denton/Garland and TXU said that the proposed 0.033 lb NO_x/MMBtu emission limit of

§117.106(b) was too restrictive and recommended higher limits and different averaging times. The Steering Committee, a 15-member group appointed by the County Judges of the DFW area to develop control strategies for the DFW ozone SIP, supported a 70% reduction and specifically requested that the commission make every effort possible to determine the feasibility of easing the 88% reduction. They recommended that the commission continue to search for the least expensive and most practical methods available to implement the utility rules so that any negative impact can be limited to the maximum extent possible. Mike Eastland for Judge Jackson and the Steering Committee asked the commission to make certain that the electric utility reductions are necessary, particularly with regard to the smaller plants that are needed for the reliability of the electric system. TXU commented that the proposal failed to follow the recommendations of the Steering Committee.

The adopted DFW SIP and individual enforceable rule measures necessary to make it approvable required a careful balancing of many factors. The commission's focus has been on the goal of developing a credible plan to attain the one-hour ozone standard. The commission believes that the adopted SIP realistically may solve a pollution problem that to date has proved to be virtually unsolvable in the largest urban areas in the country. The plan is certainly based fundamentally on quantitative analysis, much of which is dictated by EPA. The current models demonstrate the difficulty of attaining the ozone standard. Air emissions derive from most sectors of human activity, and the required reductions are large enough to require reductions from all sectors. The uncertainties involved in the vast amount of numerical analysis also introduce the need for qualitative assessments of the plan. An important insight from the model is that the benefits of reductions do not accrue linearly. When a certain threshold level is achieved, the model response improves, so that a ton of NO_x reduced produces more ozone reduction than a ton of reduction

when the overall reduction is less than the threshold level. This response indicates that plans which rely too much on marginal analyses to demonstrate attainment are more likely to fail.

The adopted SIP contains 13 measures which as a whole are projected to bring DFW back into attainment. Each measure varies in terms of costs, social impact and ozone benefit. The electric utility rule, which affects 36 boilers, is an attractive measure compared to the other measures because of its low social impact. Other measures affect far greater numbers of much smaller sources and are more difficult to implement from this standpoint.

By some statistics, for example, the highest 30-day summer period, utility reductions are the largest single NO_x reduction measure within DFW, reducing NO_x about 125 tons per day. Nonetheless, to the major utility, the modeled incremental benefit of an 88% utility reduction instead of a 70% reduction, 0.3-0.5 ppb on the single controlling day of the three days modeled for the attainment demonstration, appears to be small. The commission does not agree with this opinion and believes the incremental ozone benefit justifies the incremental cost between a 70% reduction and an 88% reduction from the peak 30-day rate. The commission agrees with the commenters that the benefits of an 88% reduction are significant. The commission modeled the total package of adopted DFW SIP measures and the resulting predicted ozone levels, as well as the qualitative WOE analyses of these results, do not support a relaxation of the electric utility reduction measures to 70%. In addition, although the science indicates clearly that the electric utility boilers reductions can only contribute to the DFW area attaining the ozone standard, rather than being alone sufficient to cause it, it is also clear from the range of variables that affect ozone formation that a single day analysis will overlook greater ozone benefits than an analysis which

considers many exceedance days. One example where greater ozone benefits from the electric utility measure might be found is if the modeling had analyzed the ozone benefits from the rule during the ozone exceedances within the 30-day period of highest utility NO_x emissions (about 140 tons per day), between July 6 and August 4, 1998.

The commission disagrees with the response to the comment that BPA and DFW are legally severe areas and require 90% point source controls. EPA designates area air quality classifications and BPA is legally classified by EPA as a moderate area and DFW as a serious area. The degree of reduction required by the rules is tied to what is needed to demonstrate attainment and there is no requirement that serious areas must apply 90% controls.

As discussed later in this preamble, the commission relaxed the emission limits somewhat while maintaining the stated goal of reducing overall utility emissions by 88%. The adjustments to the limits recognize some of the difficulties the utilities face in coming into compliance, particularly the smaller municipal utilities. The adjustments may also allow between nine and 12 of the smaller utility boilers in the large utility system to employ combustion modifications without SCR and continue to operate until replacement power and transmission capacity is constructed in the area. As adopted, the rule requires an 80% reduction from historical average third quarter emissions, and 88% from the highest 30-day period. Because the controlling emission limit is a 30-day average, the utilities must design for compliance on the highest 30-day period. The commission believes that the SIP has a greater chance of being successful by holding the line nearer the 88% reduction level as calculated in the proposed rulemaking, rather than adjusting it to 70%.

TXU said that they had voluntarily reduced NO_x emissions through several recent actions, and had supported SB 7, which requires a 50% reduction by May 2003, but the proposed rule goes far beyond the requirements of SB 7.

The commission acknowledges TXU's efforts to voluntarily reduce emissions from its DFW area boilers in 1998 and its public support for SB 7. TXU's voluntary reduction initiative has resulted in earlier air quality benefits and should lower the overall costs of compliance with the attainment demonstration emission limits of this rulemaking because of the additional time to implement and test control strategies. Although the voluntary measures and SB 7 requirements are not as extensive as the adopted rules, TXU was a participant in the SIP planning process and understood at the time that SB 7 was developed that additional NO_x reduction measures would be necessary for the DFW attainment SIP.

TXU said that the commission significantly underestimated the cost of SCR. They referenced the preamble reference to the EPA ACT document cost range of $42-74/kW and the NESCAUM cost range of $23 to $35/kW. They said the commission's selection of $30/kW represented a value near the bottom of these ranges. TXU said their DFW units consist of a large number of small units, infrequently operated units, and units that have limited space for modification. If the commission had selected a value near the upper range, $60/kW, the capital cost would have been twice as high, or $300 million.

TXU did not provide concrete information to support their $60/kW SCR capital cost estimate. The commission used the $30/kW estimate contained in the NESCAUM report spreadsheet for a

320 MW utility boiler in Appendix D, the midrange of the $25-$35/kW cost of the case study presented in Chapter 4. The rule proposal cost note explained that the commission rejected the EPA ACT estimates for SCR on gas-fired utility boilers because they were outdated and based on extrapolations from limited data. Indeed, the ACT states on page 6-96, "Due to the lack of actual installation data, an EPA analysis of SCR costs were used to estimate retrofit factors." The sentence is footnoted to a 1990 EPA study which extrapolated the West German experience on coal-fired boilers to the United States. In contrast, the NESCAUM report was written in 1998 and for the gas-fired utility boiler SCR cost estimates relies on actual project data from Southern California Edison (SCE). NESCAUM's case study of SCE's retrofit experience reports they revised their original 1991 total cost estimate of $950 million to comply with the Los Angeles utility NO_x rule (0.15 lb/MWh or about 0.01 lb/MMBtu) downward to $300 million after completion of SCR retrofits on nine of their boilers (about half of their boilers in the South Coast Air Quality Management District (SCAQMD)). Appendix H of the NESCAUM report states, "Because use of SCR in the U.S. is a relatively new phenomenon (the last ten years or so), previous reports…have relied heavily on estimates rather than actual project costs. And, due to the shortage of hard data, a great deal of judgment has been necessary in the past….Multiple conservative judgments will compound one another and result in very conservative estimates that over estimate the cost of a project. Estimates from different groups have varied quite a bit in the past. But, as the availability of information has increased, most estimates from different sources have reached some common ground. (NESCAUM) relies on a mixture of estimates and actual project data, with emphasis on the actual project data, because today there is enough hard information available on actual projects to provide a good benchmark for what is a reasonable range of SCR costs. In this sense, the information in this document is anchored in reality."

Another reason that the $30/kW cost for gas SCR appears reasonable is that the utilities endorsed these cost figures in the cost reports developed by the utilities under OTAG. The utilities would not be expected to underestimate costs, either in the OTAG report or the NESCAUM report.

Commission staff reviewed the basis of the NESCAUM estimates more thoroughly in response to TXU and Denton/Garland's comments regarding SCR capital costs. NESCAUM's case study reports that SCE bid the SCR's on a turnkey basis. In support of their comments, Denton/Garland provided commission staff the awarded SCR system costs for 15 gas-fired utility boilers located in Southern California. The 15 boilers ranged from 71 MW to 750 MW, with an average size of 379 MW and an average SCR cost, weighted by MW, of $18/kW. The individual SCR costs ranged from $12/kW for two 750 MW units up to $35/kW for one smaller, 71 MW boiler. For the nine SCE boilers, costs ranged from $12/kW for the two 750 MW units up to $18.75/kW for two 320 MW units, with an average weighted cost of $15/kW. Commission staff confirmed with the individual identified in the NESCAUM report as the knowledgeable contact for SCE that the $25-35/kW total capital cost estimate SCE provided to NESCAUM was based on a detailed analysis of the total capital costs, including additional hardware in some cases, engineering, overhead, and indirect costs on top of the installed capital cost. These costs add approximately $15/kW to the installed cost.

The commission reevaluated the cost estimates to consider the effect of boiler size in response to TXU's comment on the small size of their boilers. A logarithmic equation representing the installed cost data from the 15 Southern California SCR retrofits with $15/kW added to obtain total capital cost was applied to estimate the total capital cost of SCR for the TXU boilers. The

commission estimates that 14 of the historically most productive TXU boilers with an average size of 318 MW could be retrofitted with SCR to comply with the commission's adopted rule. Applying the cost equation from the Southern California boilers to these boilers yields an average cost of $33/kW and a total SCR capital cost of $147 million to comply with the adopted rule. Alternatively, if TXU were to manage activity levels further and apply SCR to only the 12 largest boilers with an average 350 MW size, the average cost would decline to $32.50/kW, with a total SCR capital cost of $137 million. The commission believes that the size of the TXU boilers will not cause average costs to exceed the $25-$35/kW NESCAUM estimate.

TXU said that there is a significant difference in their capital cost between a 70% reduction and an 88% reduction. They said that the 70% reduction would cost about one-third the cost of the 88% reduction, approximately $90 million versus $300 million.

As discussed in the comments on the modeling, the commission believes the difference between the ozone benefits corresponding to these NO_x reduction levels is significant. The commission agrees that the difference in capital cost is significant between a 70% reduction and an 88% reduction, but not as large as TXU indicates. As identified in the previous response, the commission believes that the capital cost of SCR on gas units is much closer to $30/kW than $60/kW. TXU's proposed 33 tons per day emission level represents only a 58% reduction from the typical third quarter/high ozone season average of 78.5 tons per day, which was the basis of the proposed rule. The commission's analysis indicates that a 33 tons per day cap could be achieved with SCRs on the three most productive boilers. However, a 70% reduction from the third quarter average requires a limit of 23.5 tons per day. Applying SCR on seven boilers (3152 MW), selecting the boilers by

size and productivity, achieves the 70% reduction at a cost of $97 million, using the revised NESCAUM estimates discussed in the previous response. The commission estimates that compliance with the adopted rule may be achieved by further applying SCR to an additional 7 boilers (1293 MW). This adds $50 million to the SCR capital cost, which becomes $147 million. Therefore, the commission estimates the difference between the 70% reduction and the 88% reduction is $97 million vs. $147 million. If one considers the estimate of total cost in DFW for NO_x compliance, including the $10/kW for combustion modifications on 5195 MW estimated necessary for RACT compliance, the total cost of a 70% reduction is $147 million versus $197 million for the 88% reduction. From the total cost viewpoint, the cost of a 70% reduction is two-thirds of the capital cost of the 88% reduction, not one-third.

TXU said that the commission significantly underestimated the potential $/ton cost for control. TXU said that the commission's estimates of total annual costs of $30.4 million and $2,721/ton did not take into account the age, frequency of operation, or total emissions from the units in its cost analysis. TXU said that the commission's cost per ton predictions are greatly underestimated for most units because of the low capacity factors of the DFW units. They said SCR on many of the low capacity factor units would be over $10,000 per ton and some over $20,000 per ton.

The commission estimated the total annual costs, cost-effectiveness in $/ton, and operating cost in $/MWh for TXU with the detailed cost spreadsheet for SCR on gas-fired utility boilers in NESCAUM, Appendix D. Age of the boilers was considered inasmuch as NESCAUM assumed an average 15-year boiler life for gas-fired boilers, shorter than coal-fired boilers in recognition of the greater average age of gas-fired peaking boilers. Frequency of operation was explicitly

included in the calculations. For example, the spreadsheet calculates variable operating costs such as ammonia consumption, catalyst replacement and disposal, and heat rate penalty, based on annual capacity factor as input. The historic 1996-1998 three-year average annual capacity factor for each TXU boiler in DFW was used in these calculations. Total emissions from the units were also considered. Annual emission reductions were calculated as an 85% reduction from the calculated average of the historical 1996-1998 annual tons NO_x reported in the acid rain data base.

Without knowledge of the future combustion modification strategies to be employed by TXU, the commission staff reasoned that the initial rate for each boiler could be assumed to be on average, the RACT limit of 0.20 lb NO_x/MMBtu. The final rate, assumed to be 0.03 lb NO_x/MMBtu, is consistent with the NESCAUM assumption of 85% removal efficiency with SCR and was selected to produce compliance with the proposed rate of 0.033 lb NO_x/MMBtu, with a small cushion for over compliance as utilities generally seek. The approximation of the initial rate as 0.20 lb/MMBtu results in lower estimated cost-effectiveness values in $/ton for most of the SCR controls than the actual compliance strategy, because the least cost control strategy will involve a combination of primary (combustion) and secondary (SCR) controls. If the combustion controls achieve a rate below 0.20 lb/MMBtu, it will reduce the reductions that the SCR will make, increasing the $/ton of the SCR. The NESCAUM spreadsheet showed that the three TXU boilers with the lowest activity levels (with 3-6% three-year annual average capacity factors–they did not operate at all in 1996 or 1997) would only achieve 80 tons per year reduction with an 85% reduction. It is not realistic to base the incremental cost-effectiveness on these three boilers because under the system cap the total required reduction is nearly 10,000 tons per year; 80 tons is less than 1.0% of the total. It would be unrealistic to assume that the 80 tons reduction could

not be achieved from other boilers which achieved greater than 85% reduction, particularly because the average SCR efficiency from the 15 Southern California boilers as reported in NESCAUM Table 2-5 is 89.6%.

TXU provided commission staff information which the staff used to estimate the emission rates in lb/MMBtu that TXU could potentially achieve on their 23 boilers using combustion modifications. The staff then re-evaluated the cost of compliance for TXU using SCR, using most of the lower combustion-modification rates assumed as the initial rate for SCR in the NESCAUM spreadsheet. The average cost-effectiveness of SCR increased from $2,610 to $3,550/ton, while the busbar cost decreased from $2.37/MWh to $2.11/MWh. Four of the boilers appeared to be controlled with FGR combustion modifications to 0.06 lb/MMBtu and the rest were at or above 0.10 lb/MMBtu. The 12 SCR scenario on the highest historical capacity factor boilers included one of the 0.06 lb/MMBtu boilers, but a more cost-effective strategy probably would reduce the level of FGR control and rely more on the SCR, improving its cost-effectiveness. An initial concentration of 0.10 was assumed on this boiler. The highest cost-effectiveness value under this scenario was $9400/ton for Mountain Creek 6, a 115 MW boiler. This small boiler was operated relatively heavily between 1996-1998. Even with some of the SCR-controlled units starting from an initial inlet concentration of 0.10 lb/MMBtu, the next highest cost-effectiveness figure for the 14 SCR scenario was less than $7,500/ton. This analysis was based on applying the SCRs to the boilers with the highest historical capacity factors. Cost-effectiveness would be improved under a more realistic compliance strategy that applied deeper combustion modifications to TXU's smaller boilers (in the revised analysis estimated from TXU's data, the combustion modifications achieve about 0.14 lb/MMBtu on the nine smaller boilers without SCR, whereas Denton/Garland

estimates they can achieve 0.06 lb/MMBtu with combustion modifications on similar sized boilers), or that shifted activity levels to maximize the 30-day capacity of the largest, best-controlled boilers. Such a detailed analysis is outside the scope of the analysis, because shifting combustion modification based rates or capacity factors would entail more unit-specific knowledge of actual costs of electric production and potential costs of combustion modifications. Under the re-evaluation scenario, the SCR on Mountain Creek 6 contributes one tpd of reduction, whereas the nine small boilers could contribute five tpd of reductions if they were controlled on average to 0.06 lb/MMBtu. Application of SCR on Mountain Creek 6 is not a likely scenario. The re-evaluation strongly suggests that the marginal cost of SCR for TXU will be less than $7,500/ton, which is within the range of costs that will be incurred by other sources in DFW in order to attain the NAAQS.

The commission notes that although the actual $/ton values for SCR are higher than estimated in the cost note, the effect of more effective combustion controls will be to lower the $/MWh costs of SCR because the variable operating cost of SCR such as ammonia consumption will be reduced. The electric production costs concern the utilities' bottom line, whereas the $/ton values are used in assessing the cost-effectiveness of control strategies. The cost note identified only the costs imposed by the proposed rule; therefore the costs of the previously adopted RACT rule, which require reducing from approximately 0.28 lb/MMBtu to 0.20 lb NO_x/MMBtu, 30-day average, were not included. The approach used in the cost note is appropriate to estimate the overall cost of compliance from the RACT level to the attainment demonstration level, but will overestimate the cost-effectiveness of SCR in $/ton for those units which can more effectively achieve lower rates with combustion controls.

TXU and Denton/Garland said that the commission failed to perform an adequate cost-benefit analysis to justify the proposed DFW SIP rules. TXU said that the proposed control level was selected arbitrarily and that the selected level rules out many cost-effective control options and mandates extensive use of SCR. Had the commission done a cost-benefit analysis, they would have identified that a 70% reduction would have obtained nearly all of the ozone reduction benefit of an 88% reduction, but at one-third the capital cost. TXU stated that this more cost-effective alternative would place SCR on the few higher emitting units and place cost-effective combustion controls on the remaining units.

The commission disagrees that the 88% reduction was picked arbitrarily. As the draft SIP progressed in 1999, it became clear that the reductions needed from the projected 2007 NO_x inventory for DFW to attain the ozone standard were large enough that the required measures went beyond the relatively straight forward and would have to include the more difficult. The adopted rule will require most of the TXU utility boilers in DFW to implement a level of control very near the highest levels currently demonstrated for such boilers. This was required because the commission could find no other set of measures less difficult that would provide the same ozone reduction benefits. The commission's modeling indicates the benefit increases an additional 0.5 ppb to 1.2 ppb (depending on which of the three modeled exceedance days is considered) in going from the 70% reduction to the 88% reduction. Additionally, the commission's analysis of the capital costs indicates a 70% control reduction would require two-thirds of the capital cost of the 88% reduction, not one-third.

TXU said that the Texas Administrative Procedure Act (APA), §2001.024(5), requires a thorough cost-benefit analysis.

The APA, §2001.024(5) requires that the commission prepare a cost note which identifies the probable economic cost to persons required to comply with the rule. The commission complied with this requirement and prepared the cost note, which was published in the *Texas Register* (24 *TexReg* 11986, December 31, 1999). The requirement here to identify the probable economic costs to persons required to comply with the rule is not a requirement to publish a cost-benefit analysis.

TXU cited Texas Health and Safety Code, §382.011 and §382.024, which they said requires the commission to perform a thorough cost-benefit analysis to ensure that the controls are, economically, the right way to regulate. They cited the General Powers and Duties of the commission §382.011(b), "The commission shall seek to accomplish the purposes of this chapter through the control of air contaminants by all practical and economically feasible methods."

The commission modeled the incremental benefits between a 70% reduction and an 88% reduction and has determined that the additional reductions are necessary for an approvable attainment demonstration. The commission's analysis of costs of the adopted requirements in combination with the flexible system cap method of compliance indicate that they are economically feasible and practical. The commission is also required by §382.002 to safeguard health.

TXU cited §382.024 which requires the commission to consider the facts and circumstances bearing on the reasonableness of emissions, including: the character and degree of injury to or interference with the public's health and physical property; the source's social and economic value; the technical practicability and economic reasonableness of reducing or eliminating the emissions resulting from the source. TXU said the commission inadequately assessed the cost of the proposed rule, and has completely failed to properly consider the differential in the extreme increase in costs the rule requires in order to gain a small amount of benefit. They said performing an earnest cost-benefit analysis is critically important when evaluating the justification for a rule as significant as this one.

The commission raised the allowable emissions from the rule proposal by revising the heat input baseline of the adopted rule. This adjustment reduces the impact on the smallest and most marginal boilers within the TXU system. The commission's analysis indicates that with this revision, the nine smallest TXU boilers could operate at an average rate of 0.14 lb/MMBtu under system cap compliance. As discussed in the responses to other comments within this preamble, the commission considered the marginal cost-effectiveness of SCR controls and the incremental ozone benefits that the adopted rule achieves and considers the additional benefits worth the costs.

TXU commented that the commission failed to provide a major environmental rule regulatory impact analysis in support of the proposed rules as required by Texas Government Code, §2001.0225. They asserted that the commission is required to perform the regulatory impact analysis because the proposed rule is a "major environmental rule" that is adopted solely under the general powers of the commission instead of under a specific state law.

The commission is not required to perform a regulatory impact analysis (RIA) because the rules do not meet any of the criteria listed in Texas Government Code, §2001.0225(a). The rules do not exceed a standard set by federal law or state law. The standard to be met in this case is the NAAQS for ozone. The state is required to demonstrate compliance with this standard under federal law, 42 USC §7410, and under state law, TCAA §382.011 and §382.012. As shown in the

modeling for the SIP that is associated with this control strategy, the state is requiring no more emission reductions than absolutely required to meet the standard. Additionally, these rules would not exceed a requirement of a delegation agreement or contract with the federal government because non exists on this topic. Finally, the rules have not been proposed under the general powers of the agency but instead have been proposed under the specific state laws found in TCAA §§382.011, 382.012, 382.016, 382.017 and 382.051(d).

In addition, the legislative history contradicts the comment that a full RIA is required of this rule. The requirement to provide a fiscal analysis of proposed regulations in the Texas Government Code was amended by SB 633 during the 75th Legislative Session. The intent of SB 633 was to require agencies to conduct a regulatory impact analysis of extraordinary rules. These are identified in the statutory language as major environmental rules that will have a material adverse impact and will exceed a requirement of state or federal law, a delegated federal program or is adopted solely under the general powers of the agency. With the understanding that this requirement would seldom apply, the commission provided a cost estimate for SB 633 that concluded "based on an assessment of rules adopted by the agency in the past, it is not anticipated that the bill will have significant fiscal implications for the agency due to its limited application." The commission also noted that the number of rules that would require assessment under the provisions of the bill was not large. This conclusion was based, in part, on the criteria set forth in the bill that exempted proposed rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law. States must develop programs for each nonattainment area to ensure that area will meet the attainment deadlines and because of the ongoing need to address nonattainment issues, the commission routinely adopts SIP rules. The

legislature is presumed to understand this federal scheme. If each rule proposed for inclusion in the SIP was considered to be a major environmental rule that exceeds federal law, then every SIP rule would require the full regulatory impact analysis contemplated by SB 633. This conclusion is inconsistent with the conclusions reached by the commission in its cost estimate and by the Legislative Budget Board (LBB) in its fiscal notes. Since the legislature is presumed to understand the fiscal impacts of the bills it passes, and that presumption is based on information provided by state agencies and the LBB, the commission believes that the intent of SB 633 was to only require the full regulatory impact analysis for rules that are extraordinary in nature. While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of the FCAA. Although the commission has determined that this is a major environmental rule because it may adversely impact in a material way a sector of the economy, these reasons support the conclusion that, the rules adopted for inclusion in the SIP fall under the exception in §2001.0225(a) because they are specifically required by federal law.

In §117.106, Denton/Garland commented that adopting a proposed level of 0.06 lb/MMBtu would satisfy the economic considerations mandated by the Major Environmental Rule statute, §2001.0225. They asserted that a thorough cost/benefit analysis as required by the statute would show that the proposed emission levels disproportionately impact the cities and the marginal benefit to ozone levels is not justified by the significant cost of SCR technology.

The commission agrees with the conclusion that the proposed emission levels disproportionately impact the cities and the marginal benefit to ozone levels is not justified by the additional cost. As discussed elsewhere in this section, the commission has substantially adopted the recommendations

made by Denton/Garland. As stated in the previous response, the commission disagrees that the commission is required to perform a regulatory impact analysis under the statute.

TXU commented that they, along with the Steering Committee, requested modeling runs done by the commission to determine the difference in impact of 70% vs 88% from electric utilities but this modeling run has not been done.

The commission has conducted the modeling run described in the comment and the results are documented in the revised SIP document.

TXU said their modeling demonstrates that a 33 tons per day level of NO_x emissions from their facilities would make a negligible difference in predicted ozone attainment, and would not significantly affect the commission's attainment demonstration. TXU said this level would still allow demonstration of attainment in the DFW area with a margin of safety.

In the SIP proposal, the commission modeled an emission cap of 14 tons per day for TXU, and in response to TXU's comments, modeled an emission cap of 33 tons per day. The commission believes that the difference in air quality benefits between the two levels justifies reductions closer to the SIP proposal. The modeled incremental benefit of an 88% utility reduction instead of a 70% reduction, 0.3-0.5 ppb on the single controlling day of the three days modeled for the attainment demonstration, is significant because the attainment demonstration can not sustain further paring down of any of the feasible measures. The model predicts the adopted measures on the controlling day would not bring ozone below the 125 ppb NAAQS; the attainment

demonstration must also rely on a WOE analysis. The incremental ozone benefit of up to 0.5 ppb is significant for the WOE and the commission's analysis indicates that the 14 tons per day limit for TXU is feasible. The commission disagrees that the modeling demonstrates that a 70% control level would still allow demonstration of attainment with a margin of safety.

Denton/Garland commented that their proposed rate of 0.06 lb NO_x/MMBtu would have negligible impact on ozone levels in the DFW area. They provided an analysis of the modeling.

The commission modeled the alternative proposed by Denton/Garland, a higher emission allowable of 0.06 lb NO_x/MMBtu on the six larger boilers and the addition of controls to meet a limit of 0.06 lb NO_x/MMBtu by surrendering the exemption on the seven smaller boilers. The commission agrees that the resulting difference in ozone levels is negligible.

TXU asserted that the modeling discussed in the preamble of the proposed DFW SIP fails to provide accurate or adequate support for the proposed rules. TXU pointed out that the rule preamble states that the commission's air quality modeling studies for the DFW area show that attaining the one-hour ozone NAAQS will be difficult, and that NO_x reductions from all modeled source categories that impact DFW's air quality will be required. They said that the modeling in the draft SIP and appendices demonstrate that attainment will be achieved when corrected biogenics and weight of evidence procedures are applied. Pages 6-31 and 6-32 of the the commission's draft "Dallas/Forth Worth Attainment Demonstration" describe commission modeling results of the latest control strategy D30. This control strategy projects a future design value of 115.3 ppb. The text goes on to say, "With this strategy, the predicted design value in the region in 2007 is nearly ten ppb below the standard. This analysis presents a highly compelling argument that the area will reach attainment by 2007." TXU said it is obvious the commission believes the control strategies and modeling will meet EPA's criteria to demonstrate attainment.

The commission stands by these statements because of the difference between the modeling deterministic test which does not predict attainment, and the WOE analysis, which does. The commission believes that under these circumstances, there is not leeway to reduce the required amount of reductions any more than absolutely necessary.

TXU commented that they hired the consultant ENVIRON to conduct a modeling analysis of the different impacts resulting from two control scenarios. The conclusion of the study, enclosed as Attachment 5, was that there is less than a 0.3 ppb difference in peak ozone in the DFW area due to the different control levels.

The commission would need to conduct the same runs to confirm or refute the analysis performed by ENVIRON. In interpreting the model results reported by ENVIRON, it is important to note that they only apply to three specific ozone exceedance days recorded in 1995 and 1996. More impact on some days and less impact on others would be seen if additional days were modeled. Because the modeling provides a narrow window of days to analyze and all exceedances may contribute to nonattainment, the narrow focus of the modeling probably underestimates the attainment benefits of reductions. Additionally, the analysis only considers peak one-hour ozone. Other important measures such as area of exceedance, hours of exceedance, and area hours of exceedance, often show greater response to emission reductions than peak ozone does.

Denton/Garland proposed that compliance be measured by either the daily/30-day cap, or on an emission rate basis in lb/MMBtu. Environmental Defense said that the rules should impose mass-based limits to guarantee that the desired emission reductions as measured in total tons are achieved and to facilitate any future transition to a cap-and-trade mechanism.

The historical capacity factor data for Denton/Garland show a rapidly increasing load growth during the 1996-1998 period. The north Dallas area has experienced very rapid population growth and this growth coupled with a very warm summer in 1998 strained the generating and transmission capacity. The commission is cognizant of the recent load growth in Denton and Garland and the existing reliability problems that this growth has caused. The uncertainty of timing of replacement of these old boilers with new generation and transmission and the reliability issue is important enough that the commission has retained the option to comply with the limits on a rate basis. The commission understands that the rate limit option does not guarantee the exact tons of reductions, but believes that the economic disincentive of running the inefficient boilers is significant enough that any operations will be minimized. In addition, the system cap offers flexibility that may be attractive enough that Denton or Garland choose this method to comply. The commission has made no changes in response to these comments.

In §117.106, Denton/Garland recommended an alternative limit of 0.06 lb NO_x/MMBtu for their facilities. They recommended creating a distinction in the rules between small and large electric generating system. They asserted that the differences in plant size and generating system size between the large electric utility and their systems in DFW resulted in disproportionate financial impact on Denton/Garland. Denton/Garland said that in order to comply with the proposed rules, it would be necessary to install SCR on all their units, while the investor-owned utilities would require SCR on about 59% of their units. They asserted that the capital cost for Denton/Garland would average $36/kW as compared to $19/kW for investor owned facilities. Denton/Garland stated that their units are aged and are expected to be retired within the next ten years as they are replaced by new units or transmission from units located outside the DFW area. They recommended applying a ten-year life rather than 15 years, as the rule preamble cost note assumed. Denton/Garland stated that the large investor owned utilities may absorb their cost of compliance through large based distribution systems and as stranded costs under SB 7. They commented that the customer base for TXU is approximately 2.8 million, whereas the combined customer base for Denton/Garland is 98 thousand. They asserted that the system cap compliance option offers cost of compliance relief to large electric generating systems, but as proposed, is of no benefit to Denton/Garland's small systems.

The commission agrees with the substance of Denton/Garland's analysis in support of a less stringent emission limit for small utility systems in DFW. The rule as proposed would result in a much higher $/KW cost of compliance for the small utilities compared to the large utility. The average size of the Denton/Garland boilers is 47 MW and for TXU is 226 MW. The small utility boilers which characterize the Denton/Garland systems have demonstrably higher $/kW SCR retrofit costs than the large utility boilers that TXU operates. TXU may comply by applying SCRs to their largest boilers; the 12 largest average 350 MW in size and the commission estimates the control cost for SCR at $32.50/kW. In contrast, the six Denton/Garland boilers subject to the proposed rule average 85 MW with a commission estimated SCR control cost of $46/kW from the Southern California SCR cost data discussed previously. There are no large boilers in the Denton

and Garland systems and not enough total boilers (two in Denton and four in Garland) to avoid the relatively more costly SCR controls on the smaller boilers.

Denton/Garland asserted that installation of SCR would require outages of four to six months as compared to one month for the combustion modifications. They said that a small system has less flexibility than a large system to remove units from service for an extended period of time.

The commission does not have information on the outages required for the Southern California utility SCR installations. NESCAUM estimated that outages to install SCR will run from at least a few weeks to a month or more. They suggested an SCR installation might ideally be scheduled with another major maintenance shutdown, such as a turbine outage. NESCAUM also stated that commissioning of an SCR system has a minimal impact to plant operations. The commission recognizes that the pace of installations is such that many of the DFW utility NO_x retrofits will not coincide with scheduled major outages. However, between Fall 2000 and May 2005, the ten low electric demand periods occurring every late Fall or early Spring provide the flexibility for all the combustion modifications and SCRs to be installed without jeopardizing reliability.

Denton/Garland asserted that a substantial capital investment in their plants cannot be justified based on the age of the plants and their heat rate. They asserted that the cost of complying with the proposed level of emission reductions would require some or all of the Denton/Garland units to be removed from operation and degrade the level of electric reliability in DFW. They stated that ERCOT has determined that the units are critical to the DFW area electric reliability and must be run during peak demand periods. They referenced the voltage-amperage reactive (VAR) support function that the generators provide during peak demand periods. They commented that several large independent power producing plants with substantially lower heat rate sited outside the four county DFW area and not subject to the proposed rules are scheduled to come on line in the next five-ten years. They asserted that it is very probable that the Denton/Garland plants will gradually be phased out or modernized within the next ten years. They stated that setting an emission rate for the cities of 0.06 lb/MMBtu will maintain electric reliability in the DFW area while new capacity is developed for the area.

The commission agrees that the cost data shows that the capital cost of electric utility boiler SCR retrofit rises steeply for small utility boilers and that these boilers have higher existing operating costs than the larger utility boilers in DFW as measured by higher boiler heat rates. The higher electric production costs of the small boilers make them much stronger candidates for retirement when new base load power comes on line in the region, which will occur within the next ten years. The phase-out of these plants within ten years is logical from an economic and environmental perspective. However, the peaking capacity these plants provide to the North Dallas area is currently a very important asset to the reliable generation of power during hot summer periods when system failure may have the greatest adverse health consequences. The exact timing of added generation and transmission capacity to bring the power into this area is uncertain, but may not be complete until after May 2005. The timing of the retirements depends on these improvements to the currently deficient DFW generating and transmission system. In addition, Denton/Garland constructively offered to control seven of their very small utility boilers which would have qualified for exemption in return for the 0.06 lb/MMBtu limit. Because the six Denton/Garland utility boilers proposed for regulation contribute only about 10% of the DFW utility NO_x, the rate change on the six boilers increases the allowable DFW utility NOx by only

7.6%. The voluntary control of the small boilers offsets this increase, so the net increase in the allowable DFW utility emissions as a result of the rate adjustment will be less than 7.6%. The commission has adopted an emission limit of 0.06 lb/MMBtu in §117.106(b) for small DFW utility systems to address the differences between the large system and the small systems regarding SCR capital costs, control cost-effectiveness, benefits of system cap compliance, heat rate, ability to absorb the additional operating cost, and potential effects on system reliability.

In §117.106, TXU observed that the proposed control levels in DFW differ substantially from the controls being applied in the BPA area for similar electric utility units. They said that there is no justification why DFW electric units should be controlled to a much lower level when modeling demonstrates no significant air quality benefit.

As discussed in the preceding comments regarding the modeled benefits of the DFW utility rules, the commission disagrees that the modeling demonstrates no significant air quality benefit of the incremental reduction from 70% to 88%. In response to the comparison to BPA, the commission's modeling indicates that the overall percentage reductions in locally generated NO_x necessary for ozone attainment are slightly deeper in DFW than in BPA. Nonetheless, the larger reason that deeper controls for the DFW electric units are necessary is because the areas have very different NO_x inventories. Attaining the ozone standard is far more difficult in DFW than in BPA because the DFW inventory is predominantly on-road and non-road mobile source based, and the available control strategies for these categories are more difficult to implement than point source controls. This is because they are less efficient, less demonstrated, slower to implement, more difficult to enforce, more expensive, or less convenient than point source controls, or in most

cases, a combination of these reasons. In addition, the DFW area has experienced growth rates in on-road and non-road mobile sources far greater than BPA, which requires deeper reductions in the projected 2007 inventories to produce similar percentage reductions. The adopted electric utility rules for DFW provide about 60 tons per day of NO_x reduction on an average day in the third quarter/high ozone season, and about 130 tons per day of NO_x reduction on the recent peak day, as measured on August 10, 1998, when total DFW area utility emissions reached 160 tons per day. The ability to combine combustion modification and SCR controls to achieve 95% plus reductions while still achieving reasonable cost-effectiveness enables higher reduction efficiencies than corresponding efficiencies for lean-burn diesel engines, a large and similarly relatively uncontrolled component of the on-road and non-road NO_x inventories. The application of SCR to achieve 90% NO_x reduction on gas-fired utility boilers is well demonstrated; Table 2-5 of the NESCAUM report lists 16 such retrofits in the Southern California region alone. Most of these boilers had already reduced emissions by more than half with combustion modifications. A similar combined combustion modification and SCR retrofit strategy has not been implemented for lean-burn engines because of the higher costs. Mobile source engines have size and weight constraints that add to the cost. In another contrast, SCR technology is less well demonstrated on diesel engines as measured by fewer diesel engines listed in the Institute of Clean Air Companies' "White Paper: SCR Control of NO_x Emissions" (November, 1997) than gas-fired utility boilers. With a population thousands of times more numerous than utility boilers, the category has proportionately much lower existing coverage. The utility SCR costs average $3,300/ton and at the margin are less than $7,500/ton, which is comparable or better than the other DFW attainment strategies. The utility strategy requires modifying no more than 36 boilers, which makes it much easier to implement than the mobile source strategies, which require early

replacement, retrofits, or inspections on engines in numbers ranging between hundreds of airport ground support equipment, thousands of heavy duty construction equipment engines, and hundreds of thousands of on-road engines. The implementation of the on-road and non-road mobile source strategies will clearly take longer, because the federal or California standards which must be applied are dependent on decades-long fleet turnover to reduce the costs of the much larger job of controlling mobile sources. The utility emission limits are easier to enforce than the other measures, since unlike any other category, most of the utility boilers are required to continuously monitor NO_x emissions under federal acid rain rules.

The control packages designed for the BPA and DFW areas were based on the best air quality modeling tools and current science. The predominance of point source emissions in BPA enables a significantly less stringent utility boiler emission limit to achieve by 2007 total percentage reductions in BPA that are similar to DFW. The more stringent electric utility emission limits in DFW are consistent with the reductions required for the area and the feasibility of achieving those reductions.

In §117.106, regarding the form of the standards, Reliant, TCC, and TXU commented that the commission should not use output based standards in the proposed rules. TCC said that most petrochemical facilities base their emissions values on fuel consumption that can easily be converted to MMBtu. They recommended retention of the input based standard, or if the commission wishes to introduce output based standards, that the option remain for the facility to choose the appropriate basis. TXU commented that existing standards, monitoring systems, and data management programs for utilities are heat-input based. Reliant stated that creating a different basis for a standard would be confusing and would unnecessarily complicate emission monitoring and reporting. Reliant also commented that the efficiency penalties associated with the required post-combustion NO_x controls would penalize the units if the standards were expressed on an output basis.

The commission did not recommend making a change but solicited comments from the regulated community to allow for constructive feedback and change if the comments indicated support for a change. The commission agrees with the reasoning provided by the commenters. Output based standards would provide little benefit for existing units and would needlessly complicate the existing regulatory procedures in place. The commission has made no change in response to the comments.

TXU said the proposed limits jeopardize electric reliability in DFW. Denton/Garland and TXU said that the costs of compliance with the proposed emission limits would force some of the units to shut down, which in turn could jeopardize electric service in DFW. Voltage drops, brownouts, or blackouts could occur during the peak summer demand, which can damage equipment and possibly cause serious health and environmental concerns during hot weather periods. They said it is essential that reliable electric power be available for air conditioning and essential services during hot weather periods. TXU and Denton/Garland attached the January, 2000 Electric Reliability Council of Texas (ERCOT) study, "Preliminary Independent System Operator (ISO) Study Report: DFW Area Possible Generation Reduction." The PUC stated that while various new plants are being built around the state, the current configuration of the Texas power generation and transmission system is not adequate to provide reliable electric service in the DFW area without maintaining or increasing the level of power generation within the DFW area. The PUC said the electric reliability issues are real and significant over the next few years, and that if an adequate balance between electric production and consumption is not maintained, the consequences for homes and businesses in DFW could be severe. They also said it is probably not economical to retrofit some of the old, small generating units to meet the proposed SIP reductions. The Steering Committee recommended that the commission give due consideration to the level of emission reductions feasible for certain older and smaller power plants so as not to affect the system reliability. Mark Burroughs, a City Councilman for Denton, expressed concern about unanticipated effects of the utility emission limit on electricity generation in the Denton area. He said that if the limit can't be complied with technologically or economically, power generation in the Denton area and in the Metroplex could be jeopardized and blackouts, brownouts, and devastating potential impacts could occur. He expressed appreciation that the commission is working with ERCOT to try to overcome the reliability questions and hoped that a tweaking of the rule comes about that will accomplish both reliability and a reduction in emissions.

A January 1999 joint PUC/TNRCC report "Electric Restructuring and Air Quality: A Preliminary Analysis of Reductions and Costs of NO_x Controls from Electric Utility Boilers in Texas," analyzed impacts of three levels of NO_x control on electric generating units owned by the major utilities in Texas and found that only a few units would likely be forced to retire at the highest level of control because the cost of controls would make their power production costs uneconomical. The highest level of control for gas-fired boilers assumed the use of SCR controls to achieve a 70-90% annual NO_x reduction, which is consistent with the reductions assumed with SCR in the analysis of this rule. The SCR costs in the PUC/TNRCC report, \$30/kW capital cost and \$2500/ton operating cost, are consistent with the cost estimates provided in the cost note for this rule, which was based on NESCAUM. Although the cost and revenue data used in the

PUC/TNRCC study were big picture estimates, the study is one of the few available indicators of the potential for unit shutdowns resulting from NO_x controls. The analysis included the DFW boilers above 50 MW owned by TXU, but did not include any of Denton and Garland's boilers. The commission considers the study one indicator that the economic impacts of the proposed Tier III controls for TXU's DFW units will not result in widespread shutdowns. A definitive analysis of which units may be shutdown by 2005 is not feasible because such analysis is highly dependent on the future price of power in the area, which depends on such factors as future demand, fuel costs, which (and when) new power projects go into operation, and the influence of a more competitive market for electricity. TXU did not provide an analysis of units that would be shutdown nor state the number of shutdowns they think would result from the proposal or other changes by the 2005 compliance date. Neither ERCOT nor the PUC have predicted such a number. ERCOT's 25% and 50% shutdown scenarios were assumptions designed to predict impacts if shutdowns occur, rather than a prediction that any units will be shut down.

In light of TXU's comments that the controls are not economically feasible, the commission has re-examined its cost estimates. The commission's cost note assumed SCR controls on all the boilers, using the NESCAUM Appendix A cost spreadsheet for SCR on gas-fired utility boilers. The spreadsheet was used to estimate the $/MWh costs of SCR for the TXU units. These estimates appear to be reasonable, because they are based on information provided by an electric utility which installed SCR on similar boilers. According to the data provided by Denton/Garland, the capital cost used by NESCAUM is high for the larger utility units. The NESCAUM model also produces higher cost estimates than the cost model on the EPA acid rain website.

The cost note examined the costs imposed by the rule but did not examine the combined costs of the existing RACT rule and the proposed rule. When the combined costs are evaluated, none of the boilers would be projected to be uneconomical to operate. The system cap flexibility allows the least cost effective units to forego SCR. The cost-effectiveness of SCR controls on the 14th boiler was estimated at $9,430/ton and $4.86/MWh using the NESCAUM spreadsheet. At this cost level, the PUC/TNRCC report did not project that the unit would become uneconomical. The commission believes that the adopted rule will not force any TXU boilers to shutdown for economic reasons because the system cap will enable TXU to overcomply on the approximately 14 boilers which would require SCR controls, thereby avoiding SCR controls on nine of their 23 boilers. The commission believes that the adjustment of the heat input basis for the system cap limit and the adjusted emission limit for the small electric utilities will provide the relief that is needed for the DFW utilities to continue to operate their units if they determine it is necessary for electric reliability.

In §117.106(c)(2), Denton/Garland, Reliant, TCC, and TXU said that the proposed five ppm ammonia emission limit was too restrictive. Denton/Garland and TXU requested a 20 ppm limit. Reliant recommended a 20 ppm one-hour limit combined with no lower than ten ppm limit, 24-hour average. TCC recommended a ten ppm ammonia limit. TCC expressed concern with increased ammonia use contributing to fine particulates and regional haze concerns. TCC said it is not clear if all vendors will guarantee a five ppm NH_3 slip at the "end of run" given the complexity of SCR operations and other factors such as catalyst fouling/poisoning which may impact overall performance. TXU and Reliant said that the five ppm limit would require oversizing catalyst; Reliant said it requires about 30% more catalyst to achieve five ppm slip versus ten ppm. Reliant said this risks greatly increasing the cost of

SCR installation if the slip limit prevents in-duct installations from being used. Reliant also said the typical feedback control of injected ammonia made it difficult to avoid ammonia spikes on peaking or load-following boilers. They said that their units in SCAQMD are subject to a 20 ppm limit, while their boilers in Ventura County are subject to a ten ppm limit. The four boilers with SCR in Ventura County have exceeded a five ppm level in five of eight tests. TXU said they already face extreme challenges to install catalyst in areas with limited space. TXU also said a too restrictive ammonia limit will reduce NO_x removal, when it may be critical for ozone attainment.

The commission proposed lower ammonia slip limits because of the increasing concern for atmospheric visibility impacts from ammonia-based particulate matter. However, the initial estimates of existing ammonia emissions in the nonattainment areas suggest that ammonia from SCR slip will be relatively small by comparison. For example, area source emissions may be 20,000 tons per year in the DFW area, while emissions from ten ppm ammonia slip from the utility boilers controlled with SCR would be less than 1.0% of this number. The commission agrees with TCC that the slip level is an "end of run" issue, so initial and average emissions are much lower. Ammonia slip emissions do not rise to the level of concern that the rules specify in-stack ammonia monitoring, so Reliant's proposal to set a 24-hour limit would be impractical to use for regulatory purposes. The commission agrees that the economic benefits of in-duct SCR installations are important. Denton/Garland provided information showing that the impact of ammonia slip limits between five and ten ppm are more consequential to the amount of catalyst required in the design of the SCR than limits between ten and 20 ppm. The adopted rule also contains a simplified approval procedure for case-specific ammonia or CO limits, that does not involve EPA approval. If the utility can show that the ability to site an SCR in-duct depends on a

design of 20 ppm slip, this could be addressed through the case-specific mechanism. In response to the comments and information received, the commission adopts an ammonia slip limit of ten ppm.

In §117.108, Entergy said they could see no reason for separate daily and 30-day limits. TXU recommended eliminating the 30-day average emission cap altogether and replacing it with a daily maximum cap. TXU recommended the commission consider an annual cap to ensure annual air emission reduction goals are achieved. They said this annual reduction should be established based on a comprehensive cost benefit analysis.

The gas-fired utility boilers operate in load following and peaking modes, which means they operate hard on hot summer afternoons and very little during much of the rest of the year. The 1996-1998 DFW utility NO_x emissions vary by a factor of more than five between the maximum daily rate (160 tons per day) and the average daily NO_x emissions outside the third quarter of the year (31 tons per day). Between these two measures are 30-day maximum, third quarter high ozone season, and annual average rates. The 30-day average emission limit functions as a flexible but controlling limit which ensures that a specified emission level is achieved during a typical peak ozone season day. The much less stringent daily maximum limit ensures that the 30-day average is not manipulated to allow higher NO_x emissions on a single day when ozone may be a problem. An annual limit can not assure the level of control required on the hot summer days when ozone is most likely to form. For example, compliance with annual limits could be achieved by importing power and reducing operations during the non-peak ozone seasons. The commission has adopted the system cap with a 30-day average and a daily maximum limit.

In §117.108, TXU said that the combination of 30-day and daily rolling average emission cap was too complex because it had to be recalculated every hour of the day. They recommended eliminating the 30-day limit and setting the cap limit based on a calendar day and maximum rated capacity. They said this would greatly simplify reporting and procedures which are unnecessarily complex, and will aid dispatchers in planning and dispatching units to reliably meet system load.

Under the system cap, the two limits, the 30-day average and the maximum daily limits, are stated as daily limits; the term "day" is defined in §117.10 as the 12 a.m. -12 p.m. calendar day. However, the term "maximum daily heat input" in proposed §117.108(c)(2) contained the language "in a 24-hour period", which implies a rolling 24-hour average limit. For clarity, the commission has revised the definition of maximum daily heat input in §117.108(c)(2) by revising "24-hour period" to "day."

In §117.108(c)(1), Entergy recommended using the highest of the nine historical months to calculate the historical period, instead of the average daily heat input over the period.

The commission agrees with the direction of this comment. Using a 30-day heat input period is appropriate for a 30-day emission limit because the controls must be designed to be capable of achieving the specified limit on any 30-day period. The acid rain database provides the data necessary to compute the maximum 30-day heat input for most utility boilers. For small boilers not monitored under the acid rain rules, the highest calendar month may be used if daily heat input records are not available. The highest calendar month heat input will be slightly lower than

the highest 30-day heat input. The commission has modified the term H_i in §117.108(c)(1) to mean the system highest 30-day heat input over the 1996-1998 period.

In §117.108(c)(1), TXU said that the proposed limit equates to an average of less than ten tons per day of emissions from all 23 of their DFW units and that this is more than a 94% reduction from the peak day.

The commission agrees with the calculations but believes historical emissions and limits are best compared over equal time periods to assess required reductions. By the commission's calculations, the proposed 30-day limit would have allowed TXU to emit 9.2 tons per day on average over a thirty day period and the proposed and adopted daily maximum limit allows 23 tons in one day. TXU's highest measured emissions over a 30-day period were 130 tons per day between July 6 and August 4, 1998, and on their highest single day was 151 tons on August 10, 1998. In comparison to the proposed 30-day limit which required an 88% reduction from the typical high ozone season day (as measured by the third quarter 1996-1998 average daily rate), the adopted 30-day limit now represents an 80% reduction from the third quarter rate and more properly, an 88% reduction from the highest 30-day period. The adopted daily maximum limit, which was not adjusted, requires an 83% reduction from the highest single day.

As an alternative to using the highest monthly heat input in §117.108(c)(1), Entergy suggested using the maximum daily cap and reducing it by a factor of 0.9 to calculate the 30-day cap. They pointed to the NSR permits program, which uses anticipated utilization factors to adjust the hourly allowable rates to annual rates. Denton/Garland recommended modifying the 30-day average emission cap in

§117.108(c)(1) for their systems by basing the heat input on 60% of potential, rather than the third quarter, three-year average historical daily rate.

The 30-day system cap limit based on historical operations assures that reductions are achieved below actual historical levels. The 30-day limit also limits more typical ozone season daily emissions by the design percentage, instead of just the highest daily emissions by this percentage. Although the commission has not modified the heat input term in response to these comments, the commission's modification of the term to reflect the highest 30-day period addresses the underlying concerns expressed in these comments.

In §117.108(c)(2), Denton/Garland recommended revising the meaning of the term "maximum daily heat input" defined in the maximum daily system cap by making it simply the maximum possible heat input rather than the lower of the maximum possible or the maximum allowed heat input.

The purpose of the distinction in the definition is to capture the highest actual level the boiler is capable of operating, but at the same time, assure that noncompliant operation above an allowable rate is not rewarded with higher allowable emissions. The maximum possible rate is a historical rate and may be higher than a nameplate rating. The commission has made no change in response to this recommendation.

TXU commented that the system cap substitution procedures in §117.108(e)(1)(A) specifies the Appendix E alternate monitoring system alternative when monitoring data is missing. For CEMS units, TXU recommended instead using the Part 75 missing data procedures applicable to CEMS units instead of Appendix E.

The commission agrees that the suggested changes will minimize costs while also ensuring that adequate substitute emissions data is reported for periods when a NO_x monitor is off-line. Therefore, the commission has revised §117.108(e) accordingly.

Reliant commented on §117.108(g), which requires the owner or operator of any unit subject to a system cap to report exceedances of the system cap emission limit. Reliant stated that the 48-hour report deadline and the 21-day report requirement are unreasonable and commented that the upset and maintenance reporting requirements of 30 TAC Chapter 101, §101.6, concerning Upset Reporting and Recordkeeping Requirements, and §101.7, concerning Maintenance, Start-up and Shutdown Reporting, Recordkeeping, and Operational Requirements, exempt boilers and gas turbines equipped with CEMS from requirements for immediate reporting and creating records. Reliant suggested that the semiannual excess emission reporting requirements are adequate to ensure that any system cap exceedances are addressed.

The specified exemptions from the upset and maintenance reporting requirements of §101.6 would not apply to exceedances which occurred for other reasons, such as failure to properly maintain control equipment or simply a failure to comply with the system cap emission limit. Reliant is correct that the new utility system cap requirements (including the reporting requirements) are borrowed from the existing source cap provisions of the industrial category NO_x RACT rule. The system cap affords unprecedented flexibility for electric utilities to comply with the Chapter 117

limits. The commission believes that the utilities must apply this flexibility responsibly, which means that the compliance accounting systems need to be able to determine when the cap is exceeded in nearly real time. The most likely times for a system cap exceedance to occur are on the hot summer days when ozone exceedances are also most likely. The commission believes the commission's ability to control air pollution is enhanced when it knows whether exceedances of total allowable utility NO_x emissions have occurred within two days after their occurrence. The commission has made no changes in response to these comments.

The EPA said that in §117.108(h), only shutdowns after the modeled emission inventory should be included in the source cap. Shutdowns that occurred before could only be used to generate credit if the previous shutdowns were carried as existing emissions in the most recent inventory relied on for the rate of progress plan or the attainment demonstration SIP.

The commission agrees and has revised §117.108(i) to specify that a shutdown is creditable only if it occurred on or after January 1, 1999. This date was selected because it is consistent with the 1996-1998 modeling period and because the baseline period for H_i, the historical heat input used in the limits of §117.108(c) is 1996-1998.

Reliant commented on §117.108(j), which states that emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 may not be included in the baseline for establishing the system cap. Reliant stated that this requirement is unnecessary.

The commission believes that it is appropriate to clearly specify that emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 may not be included in the baseline for establishing the system cap. This is necessary to ensure that no double-counting of emission reductions occurs. The commission has made no change in response to the comment.

In §117.108(k), regarding an alternative way of determining compliance with the system cap, EPA commented on the maximum daily rate data fill-in procedure, where the rule allows an owner or operator to show to the satisfaction of the executive director that the actual emissions were less than maximum emissions. The EPA stated that is unclear what replicable procedure will be used to determine whether actual emissions were less than maximum emissions. They said that if there is not a replicable procedure readily apparent in the final rule, each determination made by the executive director should be submitted to the EPA as a source specific SIP revision.

The use of the maximum emission rate for data fill-in is a last resort under the data substitution procedure in §117.108(k). Requests for executive director relief are expected to be limited because it is a last resort procedure. The commission is open to ideas on how to develop replicable procedures for this requirement. Establishing replicable procedures for infrequently applied procedures is rarely straightforward and such rule making requires full rule comment and notice. To address the concerns expressed by EPA, the commission has revised §117.108(k) to specify that each determination made by the executive director shall also require approval by the EPA.

TXU recommended a new §117.108(l) which would allow multiple ownership in a single cap if the former and new owner or operators enter into a contract agreement to meet the requirements of the section and operate the units with combined NO_x emissions in compliance with the cap. They said it was extremely important that this rulemaking address sales units so that construction of NO_x controls can be maintained for completion by the 2003 and 2005 compliance dates.

The commission believes the inclusion of two separate owners in a single utility cap is unnecessary because the compliance flexibility that TXU seeks is available through use of adopted §117.570, regarding Trading. The trading section allows one company to generate credits under the system cap and another company to apply them to their system cap. The alternative suggested by TXU makes it more difficult for the commission to determine compliance because correcting problems is more complicated when there are two entities responsible. The commission has no control over any contract between utilities. In response to this comment, the commission has modified the equations in §117.570(b)(2) and (c)(1) to clarify the calculation of system cap heat input.

In §117.203, regarding Exemptions, the EPA questioned the rationale to exempt units installed after 1992, since the rule preamble identified two companies that recently replaced boilers, and the boilers were not subject to nonattainment new source review (NNSR) requirements in the DFW area, since these rules did not apply between 1992-1999. The EPA also referenced this comment to §117.103.

The industrial boiler replacements are subject to a BACT limit of 0.06 lb NO_x/MMBtu, or about 50 ppm NO_x, higher than the adopted 30 ppm limit for the pre-1992 boilers. In developing the new §117.206 emission limits for the attainment demonstration, the commission retained the

existing §117.203 exemption for post-1992 sources because it is not clear that the level of FGR control designed to achieve the BACT limit could also meet the SIP limit, and the two limits are relatively close, compared to uncontrolled levels of 100 ppm or more. The commission notes that the NO_x NNSR requirements were in effect in DFW between November 15, 1992 and November 2, 1995 and reinstated March 21, 1999. However, the net emission change from both projects was less than NNSR trigger levels, so the NNSR rules would not have been applied to these projects in any case. Replacement equipment is not an issue in §117.103 because there have been no electric utility unit replacements in DFW or BPA since 1992. Any new units in these areas must comply with applicable NNSR requirements.

Regarding §117.206(b), Lockheed said that the NO_x emission limits are pushing the limits of combustion technology and that the new emission limits may not be achievable throughout the operating range of the boiler. They said that recent negotiations with leading companies in the field had produced a wide range between emission limits claimed in their sales pitch and the limits guaranteed under a construction contract. They said the commission should proceed cautiously and that additional controls may be required.

The new NO_x emission limit for ICI boilers in DFW was adopted about ten years ago in several air quality districts in California and has proven to be achievable with combustion modifications for boilers similar to the DFW ICI boilers. More cost-effective technologies were developed as an outgrowth of achieving compliance with the limit in California. Technological improvements and operating experience gained in California may be helpful to owners and operators of industrial boilers affected by the adopted Chapter 117 emission limits. Control techniques which focus on a

total boiler approach appear to be particularly effective in addressing the boiler operating range. The combination of FGR to achieve NO_x compliance with variable speed fans and upgraded boiler operating controls has improved fuel efficiency and combustion stability. The retrofit NO_x control market may be relatively small or fragmented compared to the boiler service base, and diligence among boiler owners or operators who must make purchasing decisions is warranted.

In §117.213(c), TCC recommended that for consistency, the monitoring applicability should continue to apply to the emission unit only, not the stack configuration. They gave the example of one large heater above the heat input threshold with two stacks, which, under stack-based applicability, it might be claimed that the emission monitoring requirements would not apply, since the heat input associated with each stack might be less than the threshold.

The estimated two additional NO_x monitors required represent a very modest increase in the number of required stack monitors, and will improve the consistency of the result, that NO_x monitoring be required where it is reasonably cost-effective. Cost-effectiveness is a function of the quantity of emissions available to measure. A stack with a large effluent from the combination of several emissions units is equally cost effective to monitor as a stack with an equally large effluent from a single emission unit. In the cited example of a large unit with split stacks, the proximity of the stacks allows both streams to be monitored by a single monitor, without significantly increasing the cost. The commission has made no changes in response to this comment.

In §117.223(b)(1), concerning Source Cap, the EPA commented on the proposed alternative procedure for calculating the actual historical average of the daily heat input in definition (B) of H_i for each unit included in the source cap. The rule allows the executive director to approve another method if historical data from 1997-1999 is not available. EPA stated that either a replicable procedure should be included in the final rule or the commission should submit each approval to EPA as a source-specific SIP revision.

In new definition (B) of the heat input term H_i in §117.223(b)(1), the baseline heat input period is updated to 1996-1999 to make it more convenient to obtain records to calculate the source cap limit under the new attainment demonstration emission specifications. Requests for executive director relief are expected to be very limited because of the updating. The commission is open to ideas on how to develop replicable procedures for this requirement. Establishing replicable procedures for infrequently applied procedures is rarely straightforward and such rulemaking requires full rule comment and notice. To address the concerns expressed by EPA, the commission has revised §117.223(b)(1) to specify that each determination made by the executive director shall also require approval by the EPA.

In §117.223, the EPA said that the proposed deletion of §117.223(g)(6) made the rule unclear. EPA asked if the deletion means that an owner or operator in all three ozone nonattainment areas cannot use shutdowns that occurred before September 10, 1993 for compliance with the RACT lean-burn engine specification. EPA said proposed new subsection (h) allows shutdowns to be included in the source cap if they occurred after September 10, 1993 in the BPA area, and after September 1, 1997 in the DFW area. Yet subsection (i) allows shutdowns after June 9, 1993 that are not permanent to be included in the source cap for the DFW area, to meet the 2001 emission limit. EPA asked that the intent be clarified for the public record.

Section §117.223(g) contains EPA's 1993 guidance for RACT on the use of shutdowns that occurred before the effective date of the RACT rules. Because the lean-burn engine RACT specifications in each nonattainment area are recent requirements that are part of the modeled attainment demonstrations for BPA and DFW, new §117.223(h) restricts the use of shutdowns for lean-burn engine compliance to the dates specified in subsection (h) to maintain consistency with the SIP. A similar provision may be proposed for compliance with any lean-burn engine emission specifications for the HGA attainment demonstration. Subsection (i) applies to the 1993 BPA and HGA RACT requirements which had a compliance date of November 15, 1999 and the 1999 DFW RACT and 2000 DFW attainment demonstration requirements which have a compliance date of March 31, 2001.

TCC said that credits from shutdown units needs to be allowed, beyond the use in the source cap compliance option.

The source cap ensures that the emissions from a shutdown unit does not end up being transferred to another unit as a result of a shift in activity from the shutdown unit to an operating unit. The plant-wide average does not address activity levels of equipment and does not ensure against this result. In a possible new cap-and-trade rule, activity levels would factor into the cap, so full credit for shutdowns could be allowed. The comment will be addressed in future trading rules being considered in a separate rule making effort and is outside the scope of the current rulemaking. The commission has made no change in response to this comment.

In §117.510 and §117.520, concerning the rule compliance schedules, EPA said that they generally view a two-year schedule for compliance as being as expeditious as practicable and that the state must show why a longer compliance time is technically and economically necessary. They said supporting data must be submitted with the SIP revision to meet the FCAA requirement for expeditious compliance.

Environmental Defense said that all of the emissions reductions required of electric generating facilities in DFW and BPA (not two-thirds as proposed) should be achieved by May 1, 2003 unless the owner or operator can demonstrate why an extension is necessary due to potential reliability impacts. They said EPA requires that emissions reductions in the SIP be implemented as expeditiously as practicable and that this is a general requirement of the FCAA and a special condition of EPA's attainment date extension for DFW and BPA due to ozone transport from Houston. They also said the Legislature and TNRCC have heretofore interpreted "expeditious" in the case of power plant controls to mean May 2003. This should be the date considered expeditious for all of the DFW area controls, unless the owner or operator of a facility can demonstrate a hardship due to reliability concerns. If the commission has information that justifies a two-year delay in the implementation of a significant portion of the reductions contained in the DFW SIP, then it should include this information in its preamble for adoption.

Environmental Defense also said a May 2003 DFW compliance date would be beneficial because implementing as many emission reduction measures as possible before 2003 will provide cleaner air to area residents sooner. An individual asked regarding the utility rules why so long to implement? - we need relief now. Another individual recommended changing the proposed 2005 compliance date to 2001. TIP and TCC said that the five-year reduction schedule proposed for the BPA and DFW areas would be difficult to meet, especially if this time frame is extended to HGA. Reliant recommended that

May 1, 2007 be the deadline for implementing controls in DFW and BPA. TIP said that for many combustion units, a five-year or greater interval between maintenance periods is common. TIP said that it could be problematic for facilities that do not have normally scheduled maintenance downtime until after May 2005 to comply by that date. TCC said that early shutdowns and requiring two-thirds of the reductions to be completed by 2003 would result in excess emissions from the startups and shutdowns and create an additional economic burden for chemical plants. TCC said that it may be more appropriate to leave the bulk of the reductions in HGA to the mid-course correction phase or even as late as the attainment year. TIP and Reliant said that the EPA has interpreted the FCAA to allow for implementation of controls as late as the attainment year; TIP said that this may be one potential solution to the maintenance scheduling problem. They also said this could allow the more costly abatement outlays to be deferred to the later years, at which time new technological innovations may have identified more cost effective approaches.

The adopted compliance schedule was developed to be as expeditious as practicable, with consideration and balancing between competing needs for economic reasonableness and expeditious reductions. The impact of the NO_x RACT schedule varies for each electric utility, but no utility had to or will have to modify all boilers to come into compliance. In contrast, the adopted attainment demonstration specifications will require reductions from all boilers that are not shut down and replaced. The adopted rules require a pace of NO_x retrofit installation on the utility boilers which is more rapid than the schedule of normal major outages. The two-year compliance schedule under NO_x RACT was appropriate for refineries and chemical plants because in general only a few units at each plant had to be modified. Regarding the schedule for industrial sources in the BPA area, industrial commenters provided data on turnaround schedules

which support the assertion made by TIP that common maintenance intervals for the boilers and heaters affected by the adopted rules are often five years or greater. Forcing early outages to retrofit equipment adds significant cost due to lost production. The phased five-year time frame, source cap, and open market trading rules provide flexibility in finding cost effective reductions which address the TCC's concerns. To some extent, TIP's and TCC's comments are directed toward the upcoming rules for the HGA area, which are outside the scope of this rulemaking. The commission will also consider these comments in the development of the HGA point source rules.

Beaumont Methanol, Inland, SETPMF, and an individual said that the compliance schedule should allow one-third of the reductions to be implemented first rather than the two-thirds as proposed. The commenters said reversing the ratio to one-third first and two-thirds last would allow the Field Study 2000 or mid-course correction to determine whether the ozone benefits from the RACT controls implemented in 1999 and upcoming RACT controls in 2001 are sufficient for the BPA area to attain in 2003. Beaumont Methanol said that the one-third down and two-thirds later would allow monitoring rather than old, questionable modeling to verify the actual need for the Phase II controls. If the area attains in 2003, then the reductions could be shown to be unnecessary. Beaumont Methanol also said that the one-third-two-thirds schedule would allow them to benefit from their early reductions and spread the cost of additional Phase II emission controls over five years instead of just three years. Environmental Defense said a May 2003 compliance date for all controls will add to the number of controls in place by 2003 whose air quality benefits can be evaluated during the planned mid-course review of the attainment demonstration. This will make the mid-course review process more meaningful and robust, rather than just another modeling exercise.

The FCAA, 42 USC §7502(c) requires that the attainment demonstration SIP must provide for implementation of all reasonably available control measures as expeditiously as practicable. Shifting the majority of the BPA reductions to 2005 would not meet this requirement. The suggested tie of the reduction schedule to the mid-course correction probably overestimates the potential for the study to quantify benefits from the BPA point source rules. The 2003 midcourse correction is going to be a holistic review of the ozone problem using all the timely improvements in the analytic tools: modeling, monitoring, aircraft-in-plume measurements, back trajectory analyses. The variable nature of the ozone problem, the three-year form of the standard, and the basic science point to the conclusion that relative progress or even compliance with the one-hour standard can't be demonstrated in a short time interval. The necessary reductions in ozone precursors are large enough that no single category of reductions can be singled out as the solution to the problem. The purpose of the midcourse correction is to ensure that the overall strategy remains effectively focused.

TCC proposed providing a procedure for sources in BPA in which individual units can obtain an extension or exemption on a case by case basis if the source owner or operator can demonstrate that the reductions cannot be made due to technical limitations, economic reasonableness, or delays in design or construction. Environmental Defense said the owner or operator should be required to demonstrate the need for extending compliance dates beyond May 2003.

Although there are existing procedures for case-by-case determinations of the compliance schedule in §117.540 for the NO_x RACT rules, the section is not open and such a procedure cannot be instated at this time. The five-year time frame, source cap, and open market trading rules

provide flexibility in finding cost effective reductions which address the TCC's concerns. The compliance schedule was developed as a balance between competing needs for reasonableness and expeditious reductions.

Entergy supported the phased compliance schedule, but recommended the first step for electric utilities in BPA to be equivalent to the SB 7 requirements.

The SB 7 baseline is the 1997 annual average emission rate for a boiler and the required control level is 0.14 lb/MMBtu; for Entergy's boilers in BPA, this equates to a 26% reduction. Establishing the first phase reduction at the SB 7 level would not achieve the desired two-thirds reductions in the first phase, which the commission believes is necessary to satisfy the FCAA requirement to achieve the reductions as expeditiously as practicable.

In §117.570, regarding Trading, EPA said that the NO_x baseline for any source under the Chapter 117 trading rules can not exceed the 2007 control strategies' NO_x emissions relied on in the attainment demonstration. TCC said there should be more consistency between Chapter 101 and 117 trading provisions and that a 1997-1999 trading baseline for a cap and trade is too restrictive. Operators should be given the option to use any data since 1990 if supporting records are available.

The commission agrees that the trading rules in Chapters 101 and 117 could be made more consistent and is committed to working to achieve this result in future rulemaking. The commission agrees with the concept that emission credits must be real and surplus at time of use. The commission does not agree with TCC that any data since 1990 should be used to set the

trading baseline. The baselines need to recognize the emission inventories modeled in the attainment demonstrations to avoid double counting of emission reductions. The commission has made no changes in response to these comments.

Denton/Garland, the PUC, and the TCC supported innovative approaches which will promote maximum flexibility. Reliant said that a mass cap and trade provision may provide some beneficial options with regard to achieving compliance with the ozone standard. TIP said it would submit comments on trading programs in conjunction with the agency's ongoing efforts to develop new trading rules. Denton/Garland recommended developing trading rules to include trading among different types of sources, incentives for early reductions, use of surplus credits for future years, and bonus credits for reductions occurring within the DFW area that can be used in the regional area.

These comments on further trading based rules are outside the scope of the rulemaking and are being considered in separate rulemaking efforts.

STATUTORY AUTHORITY

The amendments are adopted 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 amendments are also adopted under FCAA §110, 42 USC §7410.

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) utility boilers;

(2) steam generators;

(3) auxiliary steam boilers; and

(4) gas turbines.

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

§117.103. Exemptions.

(a) Units exempted from the provisions of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas), except as may be specified in §117.113(i) of this title (relating to Continuous Demonstration of Compliance), include the following:

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

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

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

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

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

(b) The fuel oil firing emission limitation of §117.105(c) or §117.107(b) of this title (relating to Emissions Specifications 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) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pound per million (MM) Btu heat input on a rolling 24-hour average and 0.20 pound per MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler or steam generator, NO_x emissions in excess of 0.38 pound per MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 pound per MMBtu heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

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

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

Figure 30 TAC §117.105(d) (No change.)

Emission Limit = [a(0.26) + b(0.30)]/(a + b)

Where:

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

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

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

(f) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in MW-hours (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of:

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

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

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit NO_x emissions in excess of a block one-hour average of:

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

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

(h) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler subject to the NO_x emission limits specified in subsections (a) - (e) of this section, carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 pound per MMBtu heat input), 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) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO.

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

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

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

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

(2) For any unit placed into service after June 9, 1993 and prior to the final compliance date as specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation) or approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or

group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (a)-(g) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.107 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

§117.106. 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 daily 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 from boilers which are part of a large DFW system, and emissions of NO_x in excess of 0.06 pound per million Btu heat input from boilers which are part of a small DFW system, on a daily average, except as provided in §117.108 of this title or §117.570 of this title. The annual heat input exemption of §117.103(2) of this title is not applicable to a small DFW system.

(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 (or alternatively, 0.30 pound per MMBtu heat input), 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 10 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 in §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) of this title;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Figure 30 TAC §117.107(d)(2) (No change.)

Where:

In-stack NO_x = NO_x (allowable) x (1 -%H_2O/100) x [20.9 -%O_2/(1 -%H_2O/100)]/5.9

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

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

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

§117.108. 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 daily and 30-day 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 rates 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 system highest 30-day period in the nine months of July, August, and September 1996, 1997, and 1998. For boilers exempt from the 40 Code of Federal Regulations Part 75 (40 CFR Part

75) monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for boilers in the system subject to 40 CFR Part 75 monitoring) is not available, the daily average of the highest calendar month heat input in 1996-1998 may be used.

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)

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

Where:

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

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

(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 continuous emissions monitoring system (CEMS):

(A) subject to 40 CFR 75, use the missing data procedures specified in 40 CFR 75, Subpart D (Missing Data Substitution Procedures);

(B) subject to 40 CFR 75, Appendix E, use the missing data procedures specified in 40 CFR 75, Appendix E, §2.5 (Missing Data Procedures);

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

(3) if the NO_x monitor is a predictive emissions monitoring system (PEMS):

(A) use the methods specified in 40 CFR 75, Subpart D;

(B) use calculations in accordance with §117.113(f) of this title; or

(4) if the methods specified in paragraphs (1) - (3) are not used, the owner or operator must use the maximum emission rate as measured by the testing conducted in accordance with §117.111(e) of this title (relating to Initial Demonstration of Compliance).

(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, provided that the permanent shutdown occurred after January 1, 1999. 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 and the EPA 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) Test for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions.

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

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

(b) The tests required by subsection (a) of this section shall be used for determination of initial compliance with the emission limits of this division. Test results shall be reported in the units of the applicable emission limits and averaging periods. If compliance testing is based on 40 Code of Federal Regulations, Part 60, Appendix A reference methods, the report must contain the information specified in §117.211(g) of this title (relating to Initial Demonstration of Compliance).

(c) Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.113 of this title (relating to Continuous Demonstration of

Compliance) shall be installed and operational before testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

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

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

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

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

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

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

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

(2) sample CO as follows:

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

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

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

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

(c) CEMS requirements.

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

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

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

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

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

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

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

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

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

(2) comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.213 of this title (relating to Continuous Demonstration of Compliance).

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section must comply with the following. The required PEMS and fuel flow meters shall be used to demonstrate continuous compliance with the emission limitations of this division.

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

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

(A) using a CEMS

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

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

(B) using a PEMS.

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

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

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

(B) §117.213(f) of this title.

(g) Gas turbine monitoring. The owner or operator of each gas turbine subject to the emission specifications of §117.105 of this title (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) for gas turbines rated less than 30 megawatt (MW) or peaking gas turbines (as defined in §117.10 of this title) which use steam or water injection to comply with the emission specifications of §117.105(g) of this title:

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

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

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

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

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

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

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

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

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

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

(2) Within 90 days after loss of the exemption, the owner or operator shall submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible, but no later than 24 months after exceeding the limit. The plan shall include a schedule of increments of progress for the installation of the required control equipment.

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

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

(l) Enforcement of NO_x limits. If compliance with §117.105 of this title is selected, no unit subject to §117.105 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.105 of this title. If compliance with §117.107 of this title is selected, no unit subject to §117.107 of this title shall be operated at an emission rate higher than that approved by the executive director pursuant to §117.115(b) of this title (relating to Final Control Plan Procedures).

§117.115. Final Control Plan Procedures 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)). The report must include a list of all units listed in §117.101 of this title, showing:

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

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

(A) §117.105 of this title;

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

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

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

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

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

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

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

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

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

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

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

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

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

(B) the maximum rated capacity for each unit;

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

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

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

(d) The report must be submitted by the applicable date specified for final control plans in §117.510 of this title (relating to Compliance Schedule For Utility Electric Generation). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with an emission limit on a rolling 30-day average, according to the applicable schedule given in §117.510 of this title.

§117.116. 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;

(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; and

(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) Start-up and shutdown records. For units subject to the start-up and/or shutdown exemptions allowed under §101.11 of this title (relating to Exemptions from Rules and Regulations), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the executive director, the Unites States Environmental Protection Agency (EPA), and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

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

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

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

(c) Reporting of test results. The owner or operator of an affected unit shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.111 of this title or any CEMS or PEMS performance evaluation conducted under §117.113 of this title:

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

(2) not later than the appropriate compliance schedules specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation 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) specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the affected unit. The nature and cause of any malfunction (if known) and the corrective action taken or preventative measures adopted;

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

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

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

(e) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records shall be kept for a period of at least five years and made available for inspection by the executive director, EPA, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit shall be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records shall include:

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

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

(3) quantity and type of fuel burned;

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

(5) emission monitoring data, pursuant to §117.113 of this title, including:

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

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

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

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

(7) records of hours of operation.

§117.121. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.105 of this title (relating to Emission Specifications 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) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

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

§117.109. Initial Control Plan Procedures.

DIVISION 3 : INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL 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 adopted 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.

§117.201. Applicability.

The provisions of this division (relating to Industrial, Commercial, and Institutional 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) commercial, institutional, or industrial boilers and process heaters with a maximum rated capacity of 40 million Btu per hour or greater;

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

(3) stationary internal combustion engines which are:

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

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

§117.203. Exemptions.

Units exempted from the provisions of this division (relating to Industrial, Commercial, and Institutional 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) any new units placed into service after November 15, 1992, except for new units which were placed into service as functionally identical replacement for existing units subject to the

provisions of this division as of June 9, 1993. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced;

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

(3) any electric utility power generating boiler;

(4) flares, incinerators, fume abaters, pulping liquor recovery furnaces, sulfur recovery units, sulfuric acid regeneration units, and sulfur plant reaction boilers;

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

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

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

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

(7) stationary gas turbines with a megawatt (MW) rating of less than 1.0 MW; and

(8) stationary internal combustion engines which are:

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

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

§117.205. Emission Specifications 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) For purposes of this subchapter, the lower of any permit nitrogen oxides (NO_x) emission limit in effect on June 9, 1993, under a permit issued pursuant to Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and the emission limits of subsections (b)-(d) of this section shall apply, except that:

(A) gas-fired boilers and process heaters operating under a permit issued after March 3, 1982, with an emission limit of 0.12 pound NO_x per million British thermal units (Btu) heat input, shall be limited to that rate for the purposes of this subchapter; and

(B) gas-fired boilers and process heaters which have had NO_x reduction projects permitted since November 15, 1990 and prior to June 9, 1993 that were solely for the purpose of making early NO_x reductions, shall be subject to the appropriate emission limit of subsection (b) of this section. The affected person shall document that the NO_x reduction project was solely for the purpose of obtaining early reductions, and include this documentation in the initial control plan required in §117.209 of this title (relating to Initial Control Plan Procedures).

(2) For purposes of calculating NO_x emission limitations under this section from existing permit limits, the following procedure shall be used:

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

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

(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 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) For each boiler and process heater with a maximum rated capacity greater than or equal to 100.0 MMBtu/hr of heat input, the applicable emission limit is as follows:

(1) gas-fired boilers, as follows:

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

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

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

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

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

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

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

(A) based on air preheat temperature:

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

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

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

(B) based on firebox temperature:

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

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

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

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

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

(5) any unit operated with a combination of gaseous, liquid, or wood fuel, a variable emission limit calculated as the heat input weighted sum of the applicable emission limits of this subsection;

(6) for any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, a multiplier of up to 1.25 times the appropriate emission limit in this subsection may be used for that eight-hour period. The total hydrogen volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of hydrogen in the fuel supply. The multiplier may not be used to increase limits set by permit;

(7) for units which operate 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), the emission limits shall apply as:

(A) the mass of NO_x emitted per unit of energy input (pound NO_x per MMBtu), on a rolling 30-day average period; or

(B) the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in pound NO_x per MMBtu; and

(8) for units which do not operate with a NO_x CEMS or PEMS under §117.213 of this title, the emission limits shall apply in pounds per hour, as specified in paragraph (7)(B) of this subsection.

(c) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10.0 MW, emissions in excess of a block one-hour average concentration of 42 parts per million by volume (ppmv) NO_x and 132 ppmv carbon monoxide (CO) at 15% oxygen (O_2), dry basis.

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

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

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

(e) No person shall allow the discharge into the atmosphere from any gas-fired, lean-burn, stationary, reciprocating internal combustion engine rated 300 hp or greater and located in the Beaumont/Port Arthur ozone nonattainment area, emissions in excess of 3.0 g NO_x/hp-hr and 3.0 g CO/hp-hr, either as:

(1) a block one-hour average limit; or

(2) a thirty-day rolling average limit. The owner or operator must ensure compliance with a 30-day rolling average using:

(A) a PEMS or CEMS under §117.213 of this title; or

(B) a monitoring system which

(i) computes predicted emissions as a function of engine speed and torque using curves or equations supplied by the engine manufacturer or developed through engine testing, which

(I) may be adjusted by engine testing; and

(II) must be shown to be consistent with the required initial and biennial compliance testing; and

(ii) monitors and records data representative of engine torque and speed at sufficient frequency to accurately compute the 30-day average NO_x.

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

(1) for gas or liquid fuel-fired boilers or process heaters, 400 ppmv at 3.0% O_2, dry basis;

(2) for wood fuel-fired boilers or process heaters, 775 ppmv at 7.0% O_2, dry basis; and

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

(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), ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

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

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

(2) any low annual capacity factor boiler, process heater, stationary gas turbine, or stationary internal combustion engine as defined in §117.10 of this title (relating to Definitions);

(3) boilers and industrial furnaces which were regulated as existing facilities by the United States Environmental Protection Agency at 40 Code of Federal Regulations Part 266, Subpart H, as was in effect on June 9, 1993;

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

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

(6) any lean-burn, stationary, reciprocating internal combustion engine located in the Houston/Galveston or Dallas/Fort Worth ozone nonattainment area; and

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

§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:

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

(2) For boilers and process heaters which do not operate with CEMS or PEMS, the emission limits shall apply as the mass of NO_x emitted per hour (pounds NO_x per hour), on a block one-hour average.

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

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

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

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

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

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

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

(2) The ammonia and carbon monoxide emission specifications of §117.205 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 of any applicable permit emission specification determined in accordance with §117.205(a) of this title, the specification of paragraph (4) of this subsection, or when applicable, subsection (i) of this section.

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

Figure 30 TAC §117.207(f)(4) (No change.)

§117.207(f)(4) OPT-IN UNITS

Equipment Class/Description	Emission Specification
fluid catalytic cracking unit carbon monoxide (CO) boilers	50% NO_x reduction across the inlet of the CO boiler to the outlet of the CO boiler, with the outlet concentration in ppmv converted into lb NO_x/MMBtu of heat input
lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 hp or greater	5.0 g NO_x/hp-hr under all operating conditions
boilers, steam generators, or process heaters with a maximum rated capacity (MRC): 40 MMBtu/hr $\leq$ MRC $<$ 100 MMBtu/hr	the emission specifications in §117.205(a) of this title for the applicable type of unit
stationary gas turbines with a MW rating: 1.0 MW $\leq$ MW rating $<$ 10.0 MW	42 ppmv NO_x at 15% O_2, dry basis
boilers and industrial furnaces which are regulated as existing facilities by the United States Environmental Protection Agency (EPA) at 40 Code of Federal Regulations (CFR) Part 266, Subpart H	the appropriate emission limitation in §117.205(b) of this title

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

(2) For each affected stationary internal combustion engine, the rate is the product of the applicable NO_x emission specification and the engine manufacturer's rated heat input (expressed in MMBtu/hr) at the engine's hp rating; divided by the product of the engine manufacturer's rated heat rate (expressed in Btu/hp-hr) at the engine's hp rating and $454(10^6)$.

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

Figure 30 TAC §117.207(g)(3) (No change.)

Where:

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

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

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

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

(4) Each affected gas-fired boiler and process heater firing gaseous fuel which contains more than 50% hydrogen (H_2) by volume, over an annual basis, may be adjusted with a multiplier of up to 1.25 times the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title.

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

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

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

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

(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. 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. This subsection is not applicable to:

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

(c) The owner or operator shall operate any unit subject to the source cap emission limits of §117.223 of this title (relating to Source Cap) in compliance with those limitations.

(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), carbon monoxide (CO), or fuel trim.

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

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

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

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

(6) Each stationary internal combustion engine controlled with nonselective catalytic reduction shall be equipped with an automatic air-fuel ratio (AFR) controller which operates on exhaust

O_2 or CO control and maintains AFR in the range required to meet the engine's applicable emission limits.

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

§117.209. Initial Control Plan Procedures.

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

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

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

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

(b) The owner or operator shall provide results of emissions testing using portable or reference method analyzers or, as available, initial demonstration of compliance testing conducted in accordance with §117.211(e) or (f) of this title (relating to Initial Demonstration of Compliance) for NO_x, carbon monoxide (CO), and oxygen emissions while firing gaseous fuel (and as applicable, hydrogen (H_2) fuel for units which may fire more than 50% H_2 by volume) and liquid and/or solid fuel at the maximum rated capacity or as near thereto as practicable, for the units listed in this subsection. Previous testing documentation for any claimed test waiver as allowed by §117.211(d) of this title shall be submitted with the initial control plan. Any units which were not operated between June 9, 1993 and April 1, 1994 and do not have earlier representative emission test results available shall be tested and the results submitted to the executive director, with certification of the equipment's shutdown period, within 90 days after the date such equipment is returned to operation. Test results are required for the following units:

(1) boilers and process heaters with a maximum rated capacity greater than or equal to 40 million British thermal units per hour (MMBtu/hr), except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title (relating to Definitions);

(2) boilers and industrial furnaces with a maximum rated capacity greater than or equal to 40 MMBtu/hr which were regulated as existing facilities by EPA at 40 Code of Federal Regulations, Part 266, Subpart H, as was in effect on June 9, 1993, except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title;

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

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

(5) stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW, except for low annual capacity factor gas turbines or peaking gas turbines as defined in §117.10 of this title; and

(6) gas-fired, stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater, except for low annual capacity factor engines or peaking engines as defined in §117.10 of this title.

(c) The initial control plan shall be submitted by April 1, 1994 and shall contain the following:

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

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

(4) identification of the election to use individual emission limits as specified in §117.205 of this title, the plant-wide emission limit as specified in §117.207 of this title, or the source cap emission limit as specified in §117.223 of this title to achieve compliance with this rule;

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

(6) a list of units requiring operating modifications to comply with §117.208(d) of this title (relating to Operating Requirements) and the type of modification to be applied for all such units, including an anticipated construction schedule;

(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, indicating the date of occurrence or anticipated date of occurrence;

(8) the basis for calculation of the rate of NO_x emissions for each unit to demonstrate that each unit will achieve the NO_x emission rates specified in this division. For fluid catalytic cracking unit CO boilers, the basis for calculation of the pound NO_x per million Btu (lb NO_x/MMBtu) rate for each unit shall include the following:

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

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

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

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

(10) for units which have had NO_x reduction projects as specified in §117.205(a)(1)(B) of this title, documentation that such projects were undertaken solely for the purpose of obtaining early NO_x reductions; and

(11) test results in accordance with subsection (b) of this section.

§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 Combustion Sources in Ozone Nonattainment Areas).

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

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

(B) liquid and solid fuel.

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

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

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

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

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

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

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

(d) Early testing conducted before March 21, 1999 may be used to demonstrate compliance with the standards specified in this division, if the owner or operator of an affected facility demonstrates to the executive director that the prior compliance testing at least meets the requirements of subsections (a), (b), (c), (e), and (f) of this section. For early testing, the compliance stack test report required by subsection (g) shall be as complete as necessary to demonstrate to the executive director that the stack test was valid and the source has complied with the rule. The executive director reserves the right to request compliance testing or CEMS or PEMS performance evaluation at any time.

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

(1) Test Method 7E or 20 (40 Code of Federal Regulations (CFR), Part 60, Appendix A) for NO_x;

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

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

(4) Test Method 2 (40 CFR 60, Appendix A) for exhaust gas flow and following the measurement site criteria of Test Method 1, Section 2.1 (40 CFR 60, Appendix A), or Test Method 19 (40 CFR 60, Appendix A) for exhaust gas flow in conjunction with the measurement site criteria of Performance Specification 2, Section 3.2 (40 CFR 60, Appendix B);

(5) American Society of Testing and Materials (ASTM) Method D1945-91 or ASTM Method D3588-93 for fuel composition; ASTM Method D1826-88 or ASTM Method D3588-91 for calorific value; or alternate methods as approved by the executive director and the United States Environmental Protection Agency (EPA); or

(6) EPA-approved alternate test methods or minor modifications to these test methods as approved by the executive director, as long as the minor modifications meet the following conditions:

(A) the change does not affect the stringency of the applicable emission limitation; and

(B) the change affects only a single source or facility application.

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

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

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

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

(4) For units complying with §117.223 of this title, a rolling 30-day average of total daily pounds of NO_x emissions from the units are monitored (or calculated in accordance with §117.223(c) of this title) for 30 successive source operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is calculated as the average of all daily emissions data recorded by the monitoring and recording system

during the 30-day test period. There must be no exceedances of the maximum daily cap during the 30-day test period.

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

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

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

(B) name and address of testing organization;

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

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

(E) description of the process being sampled; and

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

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

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

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

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

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

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

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

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

(C) deviation from reference methods, if any.

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

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

(A) field data collected on raw data sheets;

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

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

(D) emission calculations.

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

(7) Appendix. Provide:

(A) calibration work sheets for sampling equipment;

(B) collection of process logs of process parameters;

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

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

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

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

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

§117.213. Continuous Demonstration of Compliance.

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

(1) The units are the following:

(A) if individually rated more than 40 million British thermal units (Btu) per hour (MMBtu/hr):

(i) boilers;

(ii) process heaters;

(iii) boilers and industrial furnaces which were regulated as existing facilities by EPA at 40 Code of Federal Regulations (CFR) Part 266, Subpart H, as was in effect on June 9, 1993; and

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

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

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

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

(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) Oxygen (O_2) monitors.

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

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

(B) process heaters with a rated heat input:

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

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

(2) The following are not subject to this subsection:

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

(B) process heaters operating with a carbon dioxide (CO_2) CEMS for diluent monitoring under subsection (e) of this section; and

(C) wood-fired boilers.

(3) The O_2 monitors required by this subsection are for process monitoring (predictive monitoring inputs, boiler trim, or process control) and are only required to meet the location specifications and quality assurance procedures referenced in subsection (e) of this section if O_2 is the monitored diluent under that subsection. However, if new O_2 monitors are necessitated as a result of this subsection, the criteria in subsection (e) of this section should be considered the appropriate guidance for the location and calibration of the monitors.

(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) boilers with a rated heat input greater than or equal to 250 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr;

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

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

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

(F) 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) units subject to the NO_x CEMS requirements of 40 CFR 75.

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

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

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

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

(2) sample CO as follows:

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

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

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

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

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

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

(A) Section 60.13;

(B) Appendix B:

(i) Performance Specification 2, for NO_x;

(ii) Performance Specification 3, for diluent; and

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

(C) After the final compliance date, audits in accordance with §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) One CEMS may be shared among units, provided:

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

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

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

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

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

(2) Monitor diluent, either O_2 or CO_2:

(A) using a CEMS

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

(ii) with a similar alternative method approved by the executive director and EPA; or

(B) using a PEMS.

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

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

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

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

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

(A) perform the following alternative initial certification tests:

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

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

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

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

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

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

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

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

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

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

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

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

(i) at normal load operations;

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

(iii) at the following frequency:

(I) semiannually; or

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

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

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

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

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

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

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

(2) Sample:

(A) on a biennial calendar basis; or

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

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

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

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

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

(h) Monitoring for gas turbines less than 30 MW. The owner or operator of any stationary gas turbine rated less than 30 MW using steam or water injection to comply with the emission specifications of §117.205 or §117.207 of this title (relating to Alternative Plant-wide Emission Specifications) shall either:

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

(2) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption.

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

(B) The steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.205 or §117.207 of this title.

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

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

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

(1) The total H_2 volume flow in all gaseous fuel streams to the unit will be divided by the total gaseous volume flow to determine the volume percent of H_2 in the fuel supply to the unit.

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

(3) A gaseous fuel stream containing 99% H_2 by volume or greater may use the following procedure to be exempted from the sampling and analysis requirements of this subsection.

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

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

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

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

(l) Enforcement of NO_x limits. If compliance with §117.205 of this title is selected, no unit subject to §117.205 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.205 of this title. If compliance with §117.207 of this title is selected, no unit subject to §117.207 of this title shall be operated at an emission rate higher than that approved by the executive director pursuant to §117.215(b) of this title (relating to Final Control Plan Procedures 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 this division shall be permanently withdrawn.

(2) Within 90 days after loss of the exemption, the owner or operator shall submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible, but no later than 24 months after exceeding the limit. The plan shall include a schedule of increments of progress for the installation of the required control equipment.

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

§117.215. Final Control Plan Procedures 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)). 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 for each non-exempt unit;

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

(A) §117.205 of this title;

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

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

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

(E) §117.570 (relating to Trading);

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

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

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

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

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

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

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

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

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

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

(1) assign to each affected:

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

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

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

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

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

(B) the maximum rated capacity for each unit;

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

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

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

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

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

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

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

(C) the applicable restriction, R_i;

(D) the method of monitoring emissions; and

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

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

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

(e) The report must be submitted by the applicable date specified for final control plans in §117.520 of this title (relating to Compliance Schedule for 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 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;

(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; and

(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 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) Start-up and shutdown records. For units subject to the start-up and/or shutdown exemptions allowed under §101.11 of this title (relating to Exemptions from Rules and Regulations), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type of fuel burned; and the date, time, and duration of the procedure.

(b) Notification. The owner or operator of an affected source shall submit notification to the executive director, as follows:

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

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

(c) Reporting of test results. The owner or operator of an affected unit shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.211 of this title and any CEMS or PEMS relative accuracy test audit (RATA) conducted under §117.213 of this title:

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

(2) not later than the compliance schedule specified in §117.520 of this title (relating to Compliance Schedule For Industrial, Commercial, and Institutional 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 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) For units complying with §117.223 of this title (relating to Source 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) specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the affected unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;

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

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

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

ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) Reporting for engines. The owner or operator of any rich-burn engine subject to the emission limitations in §§117.205, 117.206 (relating to Emission Specifications for Attainment Demonstrations), or 117.207 (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) the magnitude of excess emissions (based on the quarterly emission checks of §117.208(d)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.213(g) of this title, computed in pounds per hour and grams per horsepower-hour, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the engine operating time during the reporting period;

(2) specific identification, to the extent feasible, of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the engine or emission control system, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(f) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain written or electronic records of the data specified in this subsection. Such records shall be kept for a period of at least five years and shall be made available upon request by authorized representatives of the executive director, EPA, or local air pollution control agencies having jurisdiction. The records shall include:

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

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

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

(i) pound per million British thermal units (Btu) heat input; and

(ii) pounds or tons per day.

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

(A) emissions measurements required by:

(i) §117.208(7) of this title; and

(ii) §117.213(g) of this title; and

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

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

(A) pounds of steam or water injected;

(B) pounds of fuel consumed; and

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

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

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

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

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

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

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

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

§117.221. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.205 of this title (relating to Emission Specifications 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) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through plant-wide averaging at maximum capacity.

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

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

Where:

i = each emission unit in the emission cap

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

H_i = (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 and EPA may approve another method for calculating H_i.

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

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

Figure 30 TAC §117.223(b)(2) (No change.)

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

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 emission unit included in the source cap shall be subject to the requirements of both paragraphs (1) and (2) of this subsection at all times.

(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 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) For stationary internal combustion engines, the source cap allowable emission rate shall be calculated in lbs per hour using the procedures specified in §117.207(g)(2) of this title.

(6) For stationary gas turbines, the source cap allowable emission rate shall be calculated in lbs per hour using the procedures specified in §117.207(g)(3) of this title.

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

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

(A) install, calibrate, maintain, and operate a continuous exhaust NO_x monitor, carbon monoxide (CO) monitor, an oxygen (O_2) (or carbon dioxide (CO_2)) diluent monitor, and a totalizing fuel flow meter in accordance with the requirements of §117.213 of this title (relating to Continuous Demonstration of Compliance). The required continuous emissions monitoring systems (CEMS) and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel use for each affected unit and shall be used to demonstrate continuous compliance with the source cap;

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

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

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

(d) The owner or operator of any units subject to a source cap shall maintain daily records indicating the NO_x emissions from each source and the total fuel usage for each unit and include a total NO_x emissions summation and total fuel usage for all units under the source cap on a daily basis. Records shall also be retained in accordance with §117.219 of this title (relating to Notification, Record keeping, and Reporting Requirements).

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

(f) 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 Combustion Sources in Ozone Nonattainment Areas).

(g) For compliance with §117.205(a)-(d) of this title by November 15, 1999, 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) the unit shall have actually operated since November 15, 1990;

(2) for purposes of calculating the source cap emission limit, the applicable emission limit for retired units shall be 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, 1990, and June 9, 1993, the actual heat input shall be the average daily heat input for the continuous time period that the unit was in service, plus one standard deviation of the average daily heat input for that period. The maximum heat input shall be the maximum heat input, as certified to the executive director, allowed or possible (whichever is lower) in a 24-hour period.

(4) 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 not been used for netting or offset purposes under the requirements of Chapter 116 of this title or have not resulted from any other state or federal requirement may be included in the baseline for establishing the cap.

(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) 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) 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) 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.

SUBCHAPTER E : ADMINISTRATIVE PROVISIONS

§§117.510, 117.520, 117.570

STATUTORY AUTHORITY

The amendments are adopted 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.

§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 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.

(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.

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

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

(C) Submit to the executive director:

(i) 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) 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:

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

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

(D) 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) 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) §117.108 of this title (relating to System Cap), or

(II) §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.

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

(C) Submit to the executive director:

(i) 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) 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:

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

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

(D) 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) 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) §117.108 of this title (relating to System Cap), or

(II) §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 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 3 of this chapter (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) as soon as practicable, but no later than the dates specified in this subsection.

(1) Reasonably available control technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter B, Division 3 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) for units operating without continuous emissions monitoring system (CEMS) or predictive emissions monitoring systems (PEMS), the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

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

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

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

(iii) no later than:

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

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

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

(D) the first semiannual report required by §117.219(d) or (e) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), covering the period November 15, 1999 through December 31, 1999, no later than January 31, 2000; and

(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 3 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) no later than November 15, 2001, submit a revised final control plan which contains:

(i) the information specified in §117.215 of this title as it applies to the lean-burn engines; and

(ii) any other revisions to the source's final control plan as a result of complying with the lean-burn engine emission specifications; and

(B) no later than January 31, 2002, submit the first semiannual report required by §117.219(e) of this title covering the period November 15, 2001 through December 31, 2001.

(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 3 of this chapter as soon as practicable, but no later than March 31, 2002 (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; 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;

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

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

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

(iii) no later than:

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

(II) May 31, 2002, 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; and

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

(c) The owner or operator of each commercial, institutional, and industrial source in the Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date). The owner or operator shall:

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

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

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

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

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

(3) submit to the executive director:

(A) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.211 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 §117.213 of this title, submit the results of:

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

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

(iii) no later than:

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

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

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

(D) the first semiannual report required by §117.219(d) or (e) of this title, covering the period November 15, 1999, through December 31, 1999, no later than January 31, 2000.

§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, 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) If the source creating the RC has been shut down or irreversibly changed, the source shall use the best available data and good engineering practice to establish the actual emissions baseline.

(2) For sources subject to the emission specifications of §§117.105, 117.106, 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) §117.108(c) of this title for compliance with §117.108 of this title;

(ii) §117.223(b)(1) of this title for compliance with §117.205(e) or §117.206 of this title, except that the term may not include one standard deviation of the average daily heat input for the period; or 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 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 §117.205(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) any applicable federally enforceable emission limitation;

(II) the reasonably available control technology (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 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 total 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:

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

or

DERCs or
MDERCS:

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

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:

(i) §117.108(c) of this title for compliance with §117.108 of this title;

(ii) §117.223(b)(1) of this title for compliance with §117.205(e) or §117.206 of this title, except that the term may not include one standard deviation of the average daily heat input for the period;

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, §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 total 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 §117.108(c) or §117.223(b)(2) of this title.

d = the total number of days in the use period

(2) An owner or operator complying with §§117.105, 117.106, 117.107, 117.205, 117.206, §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: 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.

(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 total 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, §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:

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

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.

SUBCHAPTER E : GAS-FIRED STEAM GENERATION

§117.601

STATUTORY AUTHORITY

The repeal is adopted under the Texas Health and Safety Code, Texas Clean Air Act (TCAA), §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.

§117.601. Gas-Fired Steam Generation.