The Texas Commission on Environmental Quality (TCEQ or commission) adopts amendments to §117.10, concerning Definitions; §§117.105 - 117.108, 117.113 - 117.116, 117.119, and 117.121, concerning Utility Electric Generation in Ozone Nonattainment Areas; §§117.131, 117.135, 117.138, 117.141, 117.143, and 117.149, concerning Utility Electric Generation in East and Central Texas; §§117.203, 117.205 - 117.207, 117.213 - 117.216, 117.219, 117.221, and 117.223, concerning Industrial, Commercial, and Institutional Sources in Ozone Nonattainment Areas; §§117.301, 117.309, 117.311, 117.313, 117.319, and 117.321, concerning Adipic Acid Production; §§117.401, 117.409, 117.411, 117.413, 117.419, and 117.421, concerning Nitric Acid Manufacturing - Ozone Nonattainment Areas; §§117.463, 117.465, and 117.467, concerning Water Heaters, Small Boilers, and Process Heaters; §§117.473, 117.475, 117.478, and 117.479, concerning Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources; and §§117.510, 117.512, 117.520, and 117.534, concerning Administrative Provisions; new §117.151 and §117.481, concerning Alternate Case Specific Specifications; the repeal of §117.104, concerning Gas-Fired Steam Generation, §117.540, concerning Phased Reasonably Available Control Technology (RACT), and §117.560, concerning Recission; and corresponding revisions to the state implementation plan (SIP). These new and amended sections and corresponding revisions to the SIP will be submitted to the United States Environmental Protection Agency (EPA). The commission is excluding the new §§117.135(2), 117.475(i), 117.151, and 117.481, and amended §§117.106(d), 117.121, 117.206(e), and 117.221 from the SIP in order to simplify the approval process for alternative carbon monoxide (CO) or ammonia emission specifications, thereby eliminating the need for case specific SIP revisions by the EPA to complete the approval of an alternate CO or ammonia limit.

Sections 117.10, 117.105 - 117.108, 117.113, 117.114, 117.119, 117.121, 117.131, 117.135, 117.138, 117.141, 117.143, 117.149, 117.151, 117.203, 117.205, 117.206, 117.207, 117.213 - 117.215, 117.219, 117.221, 117.223, 117.311, 117.313, 117.319, 117.321, 117.411, 117.413, 117.419, 117.421, 117.467, 117.475, 117.479, 117.481, 117.510, 117.512, 117.520, and 117.534 are adopted *with changes* to the proposed text as published in the June 21, 2002, issue of the *Texas Register* (27 TexReg 5454). Sections 117.115, 117.116, 117.216, 117.301, 117.309, 117.401, 117.409, 117.463, 117.465, 117.473, and 117.478, and the repeal of §§117.104, 117.540, and 117.560 are adopted *without changes* and will not be republished.

The adopted amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and revisions to the SIP improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, deleting obsolete language, and amending requirements to achieve the intended nitrogen oxides (NO_x) emission reductions of the program.

The commission adopts these amendments to Chapter 117 and revisions to the SIP as essential components of, and consistent with, the SIP that Texas is required to develop under the Federal Clean Air Act (FCAA) Amendments of 1990 as codified in 42 United States Code (USC), §7410, to demonstrate attainment of the national ambient air quality standard (NAAQS) for ozone. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as Houston/Galveston (HGA).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES
The HGA ozone nonattainment area is classified as Severe-17 under the 1990 Amendments to the FCAA as codified in 42 USC, §§7401 *et seq.*, and therefore is required to attain the one-hour ozone standard of 0.12 part per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined as Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of several post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base case episodes, adopted rules to achieve a 9% rate-of-progress (ROP) reduction in VOCs, and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base case episodes which marginally exhibited model performance in accordance with EPA modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the Coastal Oxidant Assessment for Southeast Texas (COAST) study. The commission believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, EPA policy regarding SIP elements and timelines went through changes. Two national initiatives in particular resulted in changing deadlines and requirements. The first of these initiatives was a program conducted by the Ozone Transport Assessment Group (OTAG). This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in the OTAG program, and OTAG concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that impacted the SIP planning process is the revision to the NAAQS for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, the one-hour standard would continue to apply until it is attained. The FCAA requires that HGA attain the one-hour standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to EPA's guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the commission eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review (MCR); and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-1999 ROP plan by December 31, 2000; and to perform an MCR review by May 1, 2004.

The emission reduction requirements included as part of the December 2000 SIP revision represented substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

A SIP revision for HGA was adopted by the commission on December 6, 2000 and submitted to the EPA by December 31, 2000. The December 2000 SIP contained rules, enforceable commitments, and photochemical modeling analyses in support of the HGA ozone attainment demonstration. In addition, this SIP contained Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contained enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit an MCR.

In January 2001, the BCCA Appeal Group (BCCA-AG) and several regulated companies challenged the December 2000 HGA SIP and some of the associated rules. Specifically, the BCCA-AG challenged the 90% NO_x reduction requirement from stationary sources in the HGA area. In May 2001, the parties agreed to a stay in the case, and Judge Margaret Cooper, Travis County District Court, signed a Consent Order, effective June 8, 2001, requiring the commission to perform an independent, thorough analysis of the causes of rapid ozone formation events and identify potential mitigating measures not yet identified in the HGA attainment demonstration, according to the milestones and procedures in Exhibit C (Scientific Evaluation) of the Consent Order.

On September 26, 2001, the commission adopted a revision to the December 2000 HGA SIP. This revision included changes to several previously adopted rules, removal of the construction equipment operating restriction and the accelerated purchase requirement for Tier 2/3 heavy duty equipment, and adjustments to the ROP and NO_x gap to account for mathematical inconsistencies. The September 2001 SIP also laid out the MCR process by detailing how the state will fulfill its commitment to obtain the additional emission reductions necessary to demonstrate attainment of the one-hour ozone standard in HGA by 2007. Chapter 7 of the September 2001 SIP described the options for reducing NO_x emissions and the anticipated results from improvements to science between 2001 and the 2004 MCR.

In compliance with the Consent Order, the commission conducted a scientific evaluation based in large part on aircraft data collected by the Texas 2000 Air Quality Study (TexAQS). The TexAQS, a comprehensive research project conducted in August and September 2000 involving more than 40 research organizations and over 200 scientists, studied ground-level ozone air pollution in the HGA and central and east Texas regions. The study revealed that while NO_x emissions from industrial sources were generally correctly accounted for, industrial VOC emissions were likely significantly understated in earlier emissions inventories. The study also showed that surface monitors were insufficient in capturing the phenomenon of ozone plumes downwind of industrial facilities. On four separate days, ozone levels exceeding 125 parts per billion were recorded by aircraft instruments that were missed by surface monitoring equipment. The findings from the study are constantly evolving and have raised questions about the formation of high ozone in the HGA. To address these findings and to fulfill obligations resulting from the lawsuit settlement negotiations with the BCCA-AG, commission staff has focused on substituting industrial VOC controls for some of the last 10% of reductions required by industrial NO_x emission limit rules and determining which VOCs should be controlled if industrial VOC controls are found to be effective.

Results of photochemical grid modeling and analysis of ambient VOC data indicate that it is possible to achieve the same level of air quality benefits with reductions in industrial VOC emissions, combined with an overall 80% reduction in NO_x emissions from industrial sources, as would be realized with a 90% reduction in industrial NO_x emissions. This conclusion is based on results from several studies, including photochemical grid modeling of the August - September 2000 episode using a top-down emissions inventory adjustment to point source highly-reactive volatile organic compound (HRVOC) emissions, and analyses of ambient HRVOC measurements made by commission automated gas chromatographs and airborne canisters using the maximum incremental reactivity (MIR) and hydroxyl (OH) reactivity scales. Four HRVOCs clearly play important roles in HGA's ozone formation, and these four (ethylene, propylene, 1,3-butadiene, and butenes) seem to be the best candidates for the first round of HRVOC controls.

In order to address these recent scientific findings, the commission is adopting revisions to the industrial source control requirements, one of the control strategies within the existing federally-approved SIP. These revisions to 30 TAC Chapter 115 are published in this issue of the *Texas Register* and include new rules to reduce emissions of HRVOCs from four key industrial sources: fugitives, flares, process vents, and cooling towers. The adopted Chapter 115 rules target HRVOCs while maintaining the integrity of the SIP. Analysis to date shows that limiting emissions of ethylene, propylene, 1,3-butadiene, and butenes in conjunction with an 80% reduction in NO_x is equivalent in terms of air quality benefit to that resulting from a 90% point source NO_x reduction requirement. As such, the HRVOC rules are performance-based, emphasizing monitoring, recordkeeping, reporting, and enforcement rather than establishing individual unit emission rates. More details about these controls are included in the SECTION BY SECTION DISCUSSION of the preamble to the Chapter 115 rules published in this issue of the *Texas Register*. The revisions to Chapter 117 implement an overall 80% reduction in industrial point source NO_x emissions, and are described in detail in the SECTION BY SECTION DISCUSSION of this preamble.

Technical support documentation accompanying this revision contains the supporting analysis for early results from ongoing analysis examining whether reductions in emissions of HRVOCs can replace the last 10% of industrial NO_x controls with a reduction of approximately 36% in industrial HRVOC emissions, while ensuring that the air quality specified in the approved December 2000 HGA SIP continues to be met.

In order to demonstrate an equivalent air quality benefit and support a revision to the NO_x strategy, the commission has been conservative in estimating VOC emissions from industrial sources and establishing the site-wide cap allocation. This methodology is conservative in that, additional adjustments may be made to the inventory as the commission learns more about the relative ambient concentrations of other VOCs, thereby reducing the burden on HRVOCs necessary for attainment purposes. Similarly, the aircraft data did not account for some of the ethylene emissions, and therefore the 1:1 NO_x to VOC ratio adjustments made to the inventory are also conservative. These types of changes may be made in the future as more analysis is completed. In terms of the equivalency determination, there are conservative assumptions applied that may change with more data assessment as part of the MCR. As a full analysis of what is ultimately necessary to fully demonstrate attainment is conducted at the MCR, the commission will be evaluating a number of issues that may change the HRVOC rules, such as: which, if any, additional chemicals need to be addressed; what is the appropriate geographic scope for the regulations; what are appropriate averaging times for the chemicals of concern; and what, if any, changes need to be made to the allocation process. By establishing a compliance date for the Chapter 115 rules approximately 18 months after the conclusion of the MCR process, the commission believes it will have ample time to make necessary adjustments and still allow industry adequate time to fully comply.

In the TABLES AND GRAPHICS section of this issue of the *Texas Register*, the table titled "Potential NO_x Emission Reductions from Implementation of the Alternate ESADs by Point Source Category for Houston/Galveston Nonattainment Area Counties - Revised 12/13/02" indicates the relative proportion of emissions according to equipment category and estimated reductions resulting from the implementation of the alternate ESADs, as well as the effect of the revisions to the utility boiler ESADs in §117.106(c)(1) and the diesel engine ESADs in §117.206(c)(9)(D) which were adopted in September 2001. The commission uses the terms "Tier I" to refer to combustion modifications, "Tier II" to refer to flue gas cleanup (i.e., post-combustion control), and "Tier III" to refer to the combination of Tier I and Tier II controls.

Figure 1: 30 TAC Chapter 117 - Preamble

POTENTIAL NO_X EMISSION REDUCTIONS FROM IMPLEMENTATION OF THE ALTERNATE ESADS* BY POINT SOURCE CATEGORY FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES - Revised 12/13/02

Category	1997 Emissions (tons per day (tpd))	% of Total Point	Tier III Reductions as adopted on 12/6/00 (%; tpd)	Tier III Reductions as adopted on 9/26/01 (%; tpd)	Tier III Reductions as adopted on 12/13/02 (i.e., the alternate ESADs) (%; tpd)
Utility Boilers	196.44	29.4	93%; 184 tpd	90%; 176 tpd[1]	86%; 169.34 tpd[1, 3]
Turbines (+Duct Burners)	155.65	23.3	91%; 141 tpd	91%; 141 tpd	78%; 121.94 tpd[3]
Heaters and Furnaces	110.12	16.5	88%; 97 tpd	88%; 97 tpd	70%; 76.95 tpd[3]
IC Engines	86.37	12.9	88%; 75 tpd	89%; 77 tpd[2, 3]	87%; 75.54 tpd[2, 3]
Industrial Boilers	85.98	12.9	92%; 79 tpd	92%; 79 tpd	89%; 76.11 tpd[3]
Other	33.19[3]	5.0[3]	59%; 19 tpd	59%; 19 tpd	49%; 16.36 tpd[3]
Overall Point Source	667.76[3]	100.0	89%; 595 tpd	88%; 588 tpd	80%; 536.24 tpd[3]

*ESAD = Emission specifications for attainment demonstration

[1]Takes into account the decrease in emission reductions of 7.42 tpd due to the September 2001 revisions to the utility boiler ESADs in §117.106(c)(1) of this title
[2]Takes into account the 1.12 tpd emission reduction due to the diesel engine ESADs in §117.206(c)(9)(D) of this title adopted in September 2001
[3]Denotes changes from the corresponding table in the October 12, 2001 issue of the *Texas Register*

Another table in the TABLES AND GRAPHICS section of this issue of the *Texas Register*, titled "Subcategories - Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties - Revised 12/13/02," further breaks down the equipment categories and indicates the estimated NO_x emission reductions which would result in the event that the alternate ESADs are implemented.

Figure 2: 30 TAC Chapter 117 - Preamble

SUBCATEGORIES - POINT SOURCE POTENTIAL NO_X EMISSION REDUCTIONS
FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES - Revised 12/13/02

Category	1997 Emissions (tons per day (tpd))	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
Utility Boilers							
Gas Wall-fired	78.11		16	50%; 39.06 tpd	90%; 70.30 tpd	85%; 66.77 tpd[2]	0.030 lb/MMBtu[2]
Gas Tangential-fired	13.34		5	30%; 4.00 tpd	90%; 12.01 tpd	80%; 10.70 tpd[2]	0.030 lb/MMBtu[2]
Coal Wall-fired	56.92		2	45%; 25.61 tpd	85%; 48.38 tpd	87%; 49.37 tpd[2]	0.050 lb/MMBtu[2]
Coal Tangential-fired	47.78		2	60%; 28.67 tpd	85%; 40.61 tpd	88%; 42.23 tpd[2]	0.045 lb/MMBtu[2]
Auxiliary Boilers	0.29		7	88%; 0.26 tpd	0%; 0 tpd	88%; 0.27 tpd [2]	0.030 lb/MMBtu[2]
Total Utility Boilers	196.44	29.4	32	50%; 97.6 tpd	87%; 172 tpd	86%; 169.34 tpd[2]	
Turbines and Duct Burners							
Electric Generation	139.06[1]		78	62%; 86.22 tpd	90%; 125.15 tpd	83%;115.84 tpd[1, 2]	0.032 lb/MMBtu[2]
Compressors >10MW	4.90		16	61%; 2.99 tpd	90%; 4.41 tpd	86%; 4.22 tpd[2]	0.032 lb/MMBtu[2]
Compressors 1-10MW	6.44		22	60%; 3.86 tpd	90%; 5.80 tpd	0%; 0 tpd[2]	0.15 lb/MMBtu[2]
Compressors <1MW	0.42		40	0%; 0 tpd	70%; 0.29 tpd	45%; 0.19 tpd[2]	0.26 lb/MMBtu[2]
Elec. Peaking/Int.	3.16		29	14%; 0.44 tpd	76%; 2.40 tpd	53%; 1.69 tpd[2]	0.032 lb/MMBtu[2]
Test Cell	0.52		4	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Chemical Processing	1.13[1]		2	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Emergency	0.02		2	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Total Turbines/DBs	155.65	23.3	193	60%; 93.51 tpd	89%; 138.05 tpd	78%; 121.94 tpd[2]	
Process Heaters/Furnaces							
Gas-fired ≥100 MMBtuh	44.08[2]		251[2]	49%; 21.60 tpd[2]	90%; 39.67 tpd[2]	75%; 33.07 tpd[2]	0.025 lb/MMBtu[2]
Gas-fired ≥40<100MMBtuh	13.29[2]		196[2]	49%; 6.51 tpd[2]	86%; 11.43 tpd[2]	77%; 10.19 tpd[2]	0.025 lb/MMBtu[2]
Gas-fired <40 MMBtuh	6.98		726	62%; 4.33 tpd	0%; 0 tpd	62%; 4.33 tpd	0.036 lb/MMBtu
Pyrolysis Rctrs ≥100MMBtuh	44.08[2]		173[2]	49%; 21.60 tpd[2]	90%; 39.67 tpd[2]	64%; 28.23 tpd[2]	0.036 lb/MMBtu[2]
Pyr.Rctrs. ≥40<100MMBtuh	1.64[2]		20[2]	49%; 0.80 tpd[2]	86%; 1.41 tpd[2]	66%; 1.09 tpd[2]	0.036 lb/MMBtu[2]
Liquid-fired	0.05		1	33%; 0.02 tpd	85%; 0.04 tpd	90%; 0.04 tpd	2 lb/M gal
Total Process Heaters	110.12	16.5	1367	50%; 54.86 tpd[2]	83%; 91.92 tpd[2]	70%; 76.95 tpd[2]	

Category	1997 Emissions (tons per day (tpd))	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
IC Engines							
Lean-burn Gas	62.15		302	70%; 43.51 tpd	90%; 55.94 tpd	93%; 57.69 tpd	0.50 g/hp-hr
Rich-burn Gas	18.56		158	0%; 0 tpd	97%; 17.94 tpd	90%; 16.73 tpd[2]	0.50 g/hp-hr[2]
Emergency Diesel	5.4		196	20%; 1.08 tpd	0%; 0 tpd	20%; 1.08 tpd	various
Other Diesel	0.20		10	20%; 0.04 tpd	0%; 0 tpd	20%; 0.04 tpd	various
Test Cell	0.08		16	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Dual-fuel	0.02		1	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	5.83 g/hp-hr
Emergency Gas	0.02		15	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Total IC Engines	86.37	12.9	699	52%; 44.63 tpd	86%; 73.88 tpd	87%; 75.54 tpd[2]	
Industrial Boilers							
Gas-fired ≥100 MMBtuh	55.46		180	60%; 33.28 tpd	90%; 49.91 tpd	92%; 51.01 tpd[2]	0.020 lb/MMBtu[2]
RCRA BIF ≥100 MMBtuh	11.24		21	0%; 0 tpd	82%; 9.22 tpd	82%; 9.22 tpd	0.015 lb/MMBtu
RCRA BIF <100 MMBtuh	1.04		20	0%; 0 tpd	54%; 0.56 tpd	54%; 0.56 tpd	0.030 lb/MMBtu
Petroleum Coke-fired	11.60		1	0%; 0 tpd	90%; 10.44 tpd	90%; 10.44 tpd	0.057 lb/MMBtu
Gas ≥40 <100 MMBtuh	3.48		90	0%; 0 tpd	87%; 3.03 tpd	74%; 2.58 tpd[2]	0.030 lb/MMBtu[2]
Gas-fired <40 MMBtuh	1.60		235	62%; 0.99 tpd	0%; 0 tpd	62%; 0.99 tpd	0.036 lb/MMBtu
Wood-fired	1.01		3	0%; 0 tpd	78%; 0.79 tpd	72%; 0.72 tpd[2]	0.060 lb/MMBtu[2]
Rice Hull-fired	0.51		1	0%; 0 tpd	90%; 0.46 tpd	90%; 0.46 tpd	0.089 lb/MMBtu
Liquid-fired	0.14		3	0%; 0 tpd	90%; 0.13 tpd	90%; 0.13 tpd	2 lb/M gal
Total Industrial Boilers	85.98	12.9	554	40%; 34.31 tpd	87%; 74.54 tpd	89%; 76.11 tpd[2]	

Category	1997 Emissions (tons per day (tpd))	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
Other							
Refinery Cat Crackers	14.93		13	0%; 0 tpd	90%; 13.44 tpd	69%; 10.35 tpd[2]	40 ppmv @0% O_2[2]
Incinerators ≥40 MMBtuh	4.02		23	0%; 0 tpd	80%; 3.22 tpd	80%; 3.22 tpd	0.030 lb/MMBtu
Incinerators <40 MMBtuh	1.93		247	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Flares	5.37		555	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Dryers - $MgCl_2$	1.05		1	0%; 0 tpd	90%; 0.95 tpd	90%; 0.95 tpd	10% of '97 rate
Dryers - Others	1.26		119	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Pulping Recovery Furnaces	1.71		3	0%; 0 tpd	64%; 1.09 tpd	64%; 1.09 tpd	0.05 lb/MMBtu
Steel Furnace ≥20 Ht Treat	0.17		4	35%; 0.06 tpd	0%; 0 tpd	35%; 0.06 tpd	0.09 lb/MMBtu
Steel Furnace ≥20 Reheat	0.66		5	50%; 0.33 tpd	0%; 0 tpd	50%; 0.33 tpd	0.06 lb/MMBtu
Steel Furnace <20MMBtuh	0.16		78	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Kilns - Lime	0.28		2	64%; 0.17 tpd	0%; 0 tpd	64%; 0.17 tpd	0.66 lb/ton CaO
Kilns - Lightweight Agg.	0.62[2]		3	30%; 0.19 tpd[2]	0%; 0 tpd	30%; 0.19 tpd[2]	1.25 lb/ton LWA[2]
Kilns - Other	0.08		14	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Nitric Acid	0.41		3	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Ovens	0.23		60	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Vents	0.18		49	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Miscellaneous	0.12		150	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Fugitives	0.01		6	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Total Other	33.19[2]	4.9	1334	2%; 0.76 tpd[2]	56%; 18.70 tpd	49%; 16.36 tpd[2]	

[1]Corrections from the corresponding table in the January 12, 2001 issue of the *Texas Register*
[2]Denotes changes from the corresponding table in the October 12, 2001 issue of the *Texas Register*

SECTION BY SECTION DISCUSSION

Formatting, punctuation, and other non-substantive corrections are made throughout the rulemaking as necessary. These corrections include the deletion of unnecessary section title references. These non-substantive corrections will not be discussed further.

Subchapter A, Definitions

The changes to §117.10, concerning Definitions, revise the definitions of boiler and industrial boiler in order to clarify that these definitions include the heating of water, rather than only the production of steam. In the October 12, 2001 issue of the *Texas Register* (26 TexReg 8141), the commission published notice that the definition of boiler inadvertently does not include large water heaters rated at greater than 2.0 million British thermal units per hour (MMBtu/hr) because the definition refers to producing steam. These units may be as large as approximately 5.0 MMBtu/hr and are no different to control than the corresponding-sized boiler. The revisions to the definitions of boiler and industrial boiler are consistent with the notice in the October 12, 2001 issue of the *Texas Register* that the commission anticipated initiating rulemaking after October 15, 2001 to add a reference to heating of water. The changes are necessary to ensure that large water heaters in HGA which are rated at greater than 2.0 MMBtu/hr (and therefore excluded from the rules for water heaters and small boilers under §§117.460 - 117.469) are subject to the emission specifications for attainment demonstration (ESADs) of §117.206(c).

The changes to §117.10 also add a definition of duct burner which is consistent with the use of this term in Chapter 117. Subsequent definitions are renumbered to accommodate the new definition.

In addition, the changes to the definition of electric generating facility (EGF) replace the term "facility" with the more accurate term "unit." The changes to §117.10 further revise the definition of electric power generating system by adding a reference to electric generating facility (EGF) accounts in the renumbered §117.10(14)(A) and (B). This change is necessary because auxiliary boilers are intended to be included (as evidenced by their inclusion in §117.101, concerning Applicability, and the emission specifications established for them in §117.105, concerning Emission Specifications for Reasonably Available Control Technology (RACT), and §117.106, concerning Emission Specifications for Attainment Demonstrations). As currently written, §117.10(13)(A) and (B) (which are being renumbered as §117.10(14)(A) and (B)) could be misinterpreted to mean that auxiliary boilers are not included because they do not, by themselves, generate electricity for compensation.

The changes to §117.10 also update the reference to the Electric Reliability Council of Texas, Inc. (ERCOT) Protocols in the definition of emergency situation to reflect the most recent version of the ERCOT Protocols. In addition, the changes to §117.10 revise the definition of heat input by abbreviating carbon monoxide, and revise the definition of megawatt (MW) rating to clarify that this definition is based on the unit's output.

The changes to §117.10 further revise the definition of incinerator to clarify that this term does not apply to a unit which functions as a control device in addition to functioning as a boiler or process heater. This is necessary to ensure that boilers and process heaters remain subject to the appropriate boiler and process heater emission specifications in the event that these units also function as VOC control devices. In addition, the changes to §117.10 revise the definition of incinerator to clarify that this term does not apply to flares, as defined in 30 TAC §101.1.

The changes to §117.10 also revise the definition of predictive emissions monitoring system (PEMS) to delete a reference to use of a graph to convert process or control device operating parameter measurements into results in units of the applicable emission limitation. This change is necessary because PEMS operate such that a conversion equation or computer program automatically performs the calculations, and the reference to "graph" in the current definition inaccurately implies that these calculations are not necessarily made automatically.

In addition, the changes to §117.10 revise the definition of stationary internal combustion engine by adding a clarification that nonroad engines, as defined in 40 Code of Federal Regulations (CFR) §89.2, are not considered stationary for the purposes of Chapter 117. The changes to §117.10 also revise the definition of "unit" to delete an extra "or" in §117.10(5)(A).

Finally, the changes to §117.10 revise the definition of utility boiler to clarify that gas turbines, including associated duct burners and unfired waste heat boilers, are not considered to be utility boilers. This revision is necessary because the current definition of utility boiler could be interpreted to include these units, which is not the intent of the definition.

Subchapter B, Combustion at Major Sources
Division 1, Utility Electric Generation in Ozone Nonattainment Areas
Section 117.104, concerning Gas-Fired Steam Generation, is being repealed because this section has been made obsolete by the passing of the March 31, 2001 RACT final compliance date specified in §117.510(b)(1) for electric utilities in the Dallas/Fort Worth (DFW) ozone nonattainment area. The requirements of §117.104 were initially adopted by the Texas Air Control Board (one of the TCEQ's predecessor agencies) in 1972, but these requirements are no longer applicable after the March 31, 2001 final compliance date.

The changes to §117.105, concerning Emission Specifications for Reasonably Available Control Technology (RACT), abbreviate pound per million Btu in §117.105(a) - (c), (g)(1) - (2), and (h). In addition, the changes to §117.105 revise a reference in §117.105(d) from "subsections (a) - (c)" to "subsections (a) and (c)" because subsection (b) does not apply to firing a mixture of natural gas and fuel oil.

The changes to §117.105 also revise §117.105(e) by adding a reference to subsection (d). This change is necessary because this subsection is not intended to apply to any auxiliary steam boiler which is an affected facility as defined by New Source Performance Standards (NSPS) 40 CFR Part 60, Subparts D, Db, or Dc. In addition, the changes to §117.105 delete a reference to §117.540 in §117.105(k)(2) because §117.540 is being repealed, as described later in this preamble. Finally, the changes to §117.105 replace the phrase "pursuant to" in §117.105(k)(1) and (2) with "in accordance with" for consistency with the agency's style guidelines.

The changes to §117.106, concerning Emission Specifications for Attainment Demonstrations, delete the alternate ESADs in §117.106(c)(5)(A) - (C) which were provided by BCCA-AG as part of the

Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC. Specifically, in January 2001, BCCA-AG and others filed suit against the commission challenging the December 6, 2000 SIP revision for HGA and five of the ten sets of rules associated with that SIP revision. As part of that lawsuit, the plaintiffs sought a temporary injunction to stay the effectiveness of these five sets of rules and for the commission to withdraw the SIP from EPA consideration. A hearing on this request was held before Judge Margaret Cooper, Travis County District Court, Texas, on May 14 - 18, 2001. Before that hearing was completed, an agreement in principle was reached to settle the lawsuit, and a Consent Order was entered by Judge Cooper which includes certain specific items included in the SIP revision and rules in 30 TAC Chapters 101 and 117 proposed by the commission on May 30, 2001 (see the June 15, 2001 issue of the *Texas Register* (26 TexReg 4380 and 4400, respectively)) and subsequently adopted on September 26, 2001 (see the October 12, 2001 issue of the *Texas Register* (26 TexReg 8110 and 8089, respectively)).

In the December 2000 adoption of the original ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of those ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. A detailed explanation of how the commission reached these conclusions is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524).

The September 26, 2001 adoption of revisions to Chapter 117 included changes to §117.106 which revised the ESAD in HGA for gas-fired utility boilers from 0.010 pound per million British thermal units (lb/MMBtu) to 0.020 lb/MMBtu in §117.106(c)(1)(A), and revised the ESAD in HGA for coal-fired or oil-fired utility boilers from 0.030 lb/MMBtu to 0.040 lb/MMBtu in §117.106(c)(1)(B). The changes had the effect of reducing the emission reduction requirement for the major HGA electric utility from 93% to 90%, based on its peak 30-day NO_x emissions in 1998. The changes similarly reduced the percentage reduction required of the other Public Utility Commission (PUC)-regulated electric utility in HGA. The justification for these changes is described in detail in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8110).

The commission is proposing to delete the current ESADs in §117.106(c)(1) - (4) and replace them with the alternate ESADs of §117.106(c)(5)(A) - (C) which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC.

The changes to §117.106 further revise §117.106(d)(2) by specifying standard oxygen (O_2) conditions for ammonia concentration measurements and add flexibility to the ammonia compliance averaging period by allowing a rolling 24-hour average for units which monitor ammonia with a continuous emissions monitoring system (CEMS) or PEMS. The reference conditions of 3.0% O_2 for boilers and 15% O_2 for gas turbines on a dry basis are standard conventions in the air pollution control industry and were inadvertently excluded in previous rulemaking. The lengthier averaging period for units which continuously monitor emissions of ammonia is consistent with existing Chapter 117 flexibility for NO_x and CO monitoring. A lengthier averaging period is easier to comply with than a comparatively shorter one and is an incentive to continuously monitor emissions. Because the ammonia slip limit is intended to apply to units equipped with selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), or SCR/SNCR hybrids for NO_x control, the revisions to §117.106(d)(2) also clarify that the ammonia slip limit applies to units which inject urea or ammonia into the exhaust stream for NO_x control.

The changes to §117.107, concerning Alternative System-wide Emission Specifications, delete obsolete references to "steam generators" in §117.107(a)(2) and (3), (c), and (d)(1). The changes to §117.107 also delete a reference to "auxiliary steam boiler" in §117.107(d)(1) that conflicts with §117.107(a)(1)(B), which specifically prohibits auxiliary steam boilers from inclusion in the system-wide emission limit. Further, the changes to §117.107 correct the type of brackets used in the equation for in-stack NO_x in the figure in §117.107(d)(2).

In addition, the changes to §117.107 add a new §117.107(e) which specifies that after the applicable attainment demonstration SIP compliance date, the alternative plant-wide RACT emission specifications will no longer apply to equipment in HGA for which §117.106(c) has established a more stringent emission specification. This will avoid any potential conflicts of the RACT limits and the more stringent ESADs. For purposes of §117.107(e), the alternative plant-wide RACT emission specifications of §117.107 remain in effect until the emissions allocation for units under the HGA mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide RACT emission specifications of §117.107.

The changes to §117.108, concerning System Cap, revise §117.108(b) to update a reference to the renumbered §117.10(14).

The changes to §117.113, concerning Continuous Demonstration of Compliance, address the relative accuracy requirement of each NO_x monitor. Previously, each NO_x monitor (CEMS or PEMS) in the Beaumont/Port Arthur (BPA), DFW, or HGA ozone nonattainment area was subject to the relative accuracy requirement of 40 CFR Part 75, Appendix B, Figure 2. That requirement allowed a concentration option (in parts per million by volume (ppmv) and/or lb/MMBtu) for the relative accuracy of any unit classified as a low emitter (<0.200 lb/MMBtu). This adoption removes that previous relative accuracy option and replaces it with a more restrictive option which will provide better confidence in the monitor's ability to make low-level measurements for NO_x. It also levels the relative accuracy requirements for utility and industrial, commercial, and institutional (ICI) monitors. Commission staff discussed the current Part 60 expectation and capability with EPA's Emission Measurement Center (EMC) staff. EMC staff stated that the reference method, when implemented with a good tester and good equipment, should be able to provide results within one ppmv of the CEMS. Commission staff believe that the current monitors and procedures may not necessarily provide this capability for low-level measurements. The commission expects EPA to develop new monitor requirements/procedures in the future and temporarily defers a more restrictive relative accuracy option than two ppmv and/or future changes of relative accuracy requirement until such time that commission staff have more experience with the low-level monitor certification and/or EPA recommendations. The commission solicited comments, recommendations, and input in the relative accuracy level required to assure and document compliance with emissions limits of ten ppmv and below; these comments are addressed later in this preamble under the RESPONSE TO COMMENTS heading.

The changes to §117.113 also revise §117.113(c)(2) and add a new §117.113(c)(3) to address the sharing of CEMS among more than one unit. The existing §117.113(c)(2) was developed for the NO_x RACT rules, with which affected units typically comply by meeting an individually enforceable limit, either directly through §117.105 or through averaging in accordance with §117.107. However, compliance with §117.106(c) and the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, concerning Mass Emissions Cap and Trade Program, in HGA is demonstrated through a limit on total annual tons of NO_x emitted to the atmosphere, such that it would be more effective for the NO_x CEMS requirements to be linked to stacks, rather than individual units. The new §117.113(c)(3) enables the sharing of CEMS in this manner in HGA. The new §117.113(c)(3) also specifies that all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack. This is necessary because under the mass emissions cap and trade program, all NO_x emissions are considered, including those from startup, shutdown, upset, and maintenance activities at affected units. The new §117.113(c)(3) further specifies that exhaust streams of units which vent to a common stack do not need to be analyzed separately.

The changes to §117.113 further revise §117.113(h) by specifying that in lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. It only makes sense to apply this alternate technique on units that run only at full load or units that operate infrequently. Application to units that run at partial load more frequently would overestimate emissions. While there may be some slight overestimation of NO_x emissions for units that run only at full load or units that operate infrequently, it is offset by the savings associated with not having to install fuel flow monitors on units with minimal operation.

In addition, the changes to §117.113 delete two section titles in §117.113(g) and (h)(1) because the titles are included earlier in this section in the changes to §117.113(c)(2) and (3). The changes to §117.113 also abbreviate "megawatt" because this term is abbreviated earlier in this section. Finally, the changes to §117.113 replace the phrase "pursuant to" with "in accordance with" for consistency with the agency's style guidelines.

The changes to §117.114, concerning Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration, add a new §117.114(a)(4) which requires that ammonia monitoring be applied to units which inject urea or ammonia into the exhaust stream for NO_x control. The commission is adopting several options for ammonia slip monitoring in order to provide flexibility and minimize cost. The first option is to calculate the slip with a mass balance, as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of SCR. Because this option relies on process parameters routinely monitored in SCR systems, it is the least expensive procedure and is commonly specified in new source review (NSR) permits. The permits typically require annual calibration of this method using a stack emission test for ammonia. The commission solicited comments on the usefulness of this stack test calibration based on recent experience; these comments are addressed later in this preamble under the RESPONSE TO COMMENTS heading. The second option is to monitor ammonia slip more directly by splitting the exhaust sample stream, converting the ammonia to nitric oxide (NO) in one stream with a thermal oxidizer, and measuring the ammonia as the difference between the converted and unconverted samples. This is the slip monitoring approach recommended by the Institute of Clean

Air Companies at http://www.icac.com/noxgaswp.pdf. By alternately measuring streams, it may be feasible to monitor ammonia using an already required downstream NO_x analyzer, which would eliminate the cost of a separate analyzer. The third option is to conduct weekly ammonia sampling using stain tubes. This method has been specified in NSR permits. A fourth option is to use another method as approved by the executive director. A number of commercial methods of monitoring ammonia slip are described in the EPA's "Ammonia CEMS Background Report," June 14, 1993, available at http://www.epa.gov/ttn/emc/cem.html.

Control of the excess ammonia generation is a part of the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent, and a competently designed and operated post-combustion control system will minimize excess ammonia generation. Minimizing ammonia slip depends on designing the system such that injected ammonia is properly-mixed and well-distributed and such that the amount of catalyst (in the case of SCR) is sufficient to control both NO_x and ammonia to the desired levels. Nevertheless, there will be an increase in ammonia emissions due to ammonia slip associated with the use of post-combustion control technologies. It is desirable to minimize ammonia emissions due to the concern that significantly increased ammonia emissions will enhance formation of fine particulate matter (PM) of less than 2.5 microns ($PM_{2.5}$). Consequently, monitoring for ammonia emissions is necessary. The changes to §117.114 also renumber the existing §117.114(a)(4) as §117.114(a)(5).

In addition, the changes to §117.114 revise §117.114(c)(2)(C) to clarify that any retesting at a unit not equipped with a CEMS or PEMS establishes a new emission factor to be used to calculate actual emissions from the date of the retesting forward, with the previously determined emission factor used to calculate actual emissions for compliance with the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 until the date of the retesting.

The changes to §117.114 also add a new §117.114(c)(2)(D) which requires that all test reports be submitted to the executive director for review and approval within 60 days after completion of the testing. This is consistent with the existing requirements of Chapter 117 and is necessary to ensure the integrity and accuracy of testing.

The changes to §117.115, concerning Final Control Plan Procedures for Reasonably Available Control Technology, delete an incorrect section title in §117.115(a)(1) and correct the reference to §117.570 in §117.115(a)(2)(D) to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)).

The changes to §117.116, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, correct the reference in §117.116(a)(1)(C) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)).

The changes to §117.116 also add a new §117.116(a)(1)(D) which adds a reference to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3. This reference is necessary to ensure that sources in HGA submit the required information necessary to document compliance (for example, the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates).

The changes to §117.119, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.119(a) by replacing a reference to 30 TAC §101.11, concerning Demonstrations, with a reference to 30 TAC §101.222, concerning Demonstrations. Section 101.222 was adopted in the September 6, 2002 issue of the *Texas Register* (27 TexReg 8499) and replaced §101.11.

The changes to §117.119 also revise §117.119(b)(1) to clarify that verbal notification of the date of any testing conducted under §117.111 must be made at least 15 days prior to such date followed by written notification within 15 days after testing is completed. Likewise, the changes to §117.119(c) clarify that results of testing conducted under §117.111 must be provided to the TCEQ central and regional offices and any local air pollution control agency having jurisdiction. This revision is necessary to ensure that any retesting conducted under §117.114(c)(2) is subject to the same notification and test result reporting requirements as the initial test.

The changes to §117.121, concerning Alternative Case Specific Specifications, clarify that requests for alternate CO or ammonia limits are evaluated by the Engineering Services Team, Office of Compliance and Enforcement. It should be noted that the paragraphs (§117.106(d) and §117.206(e)) addressing pollutants which may increase as an incidental result of compliance with the NO_x limits, specifically, CO and ammonia, continue to be excluded from the SIP. The changes to §117.121 also change a reference in §117.121(a)(2) from RACT to §117.105 or §117.106. This change is necessary because the ESADs of §117.106 go beyond RACT in some cases.

The changes to §117.121 also delete the reference to §50.39 and to filing a motion for reconsideration from §117.121(b) because §50.39 only applies to any application that is declared administratively complete before September 1, 1999. The reference to §50.139, which applies to any application that is declared administratively complete on or after September 1, 1999, is appropriate and has been retained.

Subchapter B, Combustion at Major Sources
Division 2, Utility Electric Generation in East and Central Texas
The changes to §117.131, concerning Applicability, add a new §117.131(b) which specifies that the provisions of §117.134, concerning Gas-Fired Steam Generation, also apply in Palo Pinto County. This is necessary because units in Palo Pinto County are subject to §117.134 (Gas-Fired Steam Generation, initially adopted by the Texas Air Control Board in 1972), but Palo Pinto County is not included in the counties listed in the existing §117.131(4). The changes to §117.131 further add a missing division title to the relettered §117.131(a).

In addition, the changes to §117.131 and to §117.135, concerning Emission Specifications, make it clear that duct burners in gas turbine exhaust ducts are included in the applicability of Subchapter B, Division 2, Utility Electric Generation in East and Central Texas. This will ensure that emissions from a duct burner are subject to the same emission specification as the associated gas turbine of which the duct burner is an integral part.

The changes to §117.135 also add a new paragraph (2) which establishes an ammonia emission limit of ten ppmv ammonia. The new limit is necessary to prevent large increases in ammonia emissions concurrent with the installation of NO_x controls. This limit is consistent with the corresponding limit for ammonia in §117.106, and represents a maximum rate under good engineering practice. Initial testing for this pollutants is already required under §117.141(a)(2), concerning Initial Demonstration of Compliance. The commission is excluding this related pollutant limit of §117.135(2) from the SIP in order to simplify the approval process for alternative emission specifications under the new §117.151, concerning Alternative Case Specific Specifications. This step will eliminate the need for case specific SIP revisions by the EPA to complete the approval of an alternate ammonia limit. The current §117.135(1) and (2) is renumbered as §117.135(1)(A) and (B) to accommodate the new §117.135(2). Because the ammonia slip limit is intended to apply to units equipped with SCR, SNCR, or SCR/SNCR hybrids for NO_x control, the new §117.135(2)(B) also specifies that the ammonia slip limit applies to units which inject urea or ammonia into the exhaust stream for NO_x control.

The changes to §117.138, concerning System Cap, revise §117.138(b) to update a reference to the renumbered §117.10(14), add the acronym "PEMS" to §117.138(e)(3), and revise §117.138(e)(3)(B) to update a reference to the renumbered §117.143(e) which is described later in this preamble.

The changes to §117.141 revise the reference in §117.141(a) from Subchapter B, Division 2 to §117.135. This change is necessary to prevent units which are subject to §117.134 (Gas-Fired Steam Generation, initially adopted by the Texas Air Control Board in 1972) but which are not subject to §117.135, from inadvertently being subject to the testing requirements of §117.141. The changes to §117.141 also add a missing division title to §117.141(b). In addition, the changes to §117.141 revise §117.141(d) to correct a typographical error in the abbreviation of "pound per million British thermal units."

The changes to §117.143, concerning Continuous Demonstration of Compliance, revise §117.143(b) to specify that if an owner or operator chooses to monitor CO exhaust emissions from a unit subject to the emission specifications of §117.135, several listed methods should be considered appropriate guidance for determining CO emissions. The methods for this optional CO monitoring are as follows. A portable analyzer can be used, reference method testing can be conducted, or a CEMS or PEMS for CO can be installed. Limits on CO emissions are desirable to prevent large increases in CO emissions concurrent with the installation of NO_x controls. Initial testing for CO is already required under §117.141(a)(1).

In addition, the changes to §117.143 delete the requirements for auxiliary boilers in the existing §117.143(e) because auxiliary boilers do not meet the applicability criteria described in §117.131, and renumber subsequent subsections due to the deletion of subsection (e). The changes to §117.143 also revise the renumbered §117.143(e)(2)(A)(i) to correct a reference to the CEMS requirements of §117.143(c). Finally, the changes to §117.143 revise the renumbered §117.143(g)(3) and (i) to delete the wording "low annual capacity factor" from the reference to the exemption of §117.133, since these exemptions do not use this wording.

For units which are included in a system cap under §117.138, it is more effective for the NO_x CEMS requirements to be linked to stacks, rather than individual units. Therefore, the commission has added a new §117.143(c)(3) which enables the sharing of CEMS in this manner. The new §117.143(c)(3) also specifies that all bypass stacks must be monitored in order to quantify emissions directed through the bypass stack. This is necessary because under the system cap, all NO_x emissions are considered, including those from startup, shutdown, upset, and maintenance activities at affected units. The new §117.143(c) further specifies that exhaust streams of units which vent to a common stack do not need to be analyzed separately.

Finally, the changes to §117.143 clarify that the gas turbine monitoring requirements of §143(f)(1)(B) apply to units which are not included in a system cap under §117.138. This clarification is necessary because units which are included in a system cap under §117.138 must demonstrate compliance through NO_x CEMS or PEMS because the data under §143(f)(1)(B) is not sufficient to demonstrate compliance under the system cap.

The changes to §117.149, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.149(a) by replacing a reference to §101.11 with a reference to §101.222. Section 101.222 was adopted in the September 6, 2002 issue of the *Texas Register* (27 TexReg 8499) and replaced §101.11.

The new §117.151 allows an alternative emission specification to be established on a case-specific basis for ammonia. The commission is excluding this related pollutant limit from the SIP in order to simplify the approval process for alternative emission specifications. This step will eliminate the need for case-specific SIP revisions by the EPA to complete the approval of an alternate ammonia limit.

Subchapter B, Combustion at Major Sources
Division 3, Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas
The changes to §117.203, concerning Exemptions, revise §117.203(a) to include a reference to §117.219(f)(10) to ensure that the necessary records are maintained to demonstrate compliance with the diesel engine and dual-fuel engine testing and maintenance operating hour restrictions of §117.206(i). The changes to §117.203 also clarify §117.203(a)(1) by adding a reference to §117.205(a)(3), concerning Emission Specifications for Reasonably Available Control Technology (RACT), for functionally identical replacement units. The changes to §117.203 further revise §117.203(a)(2) by changing "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the remainder of this division.

In addition, the changes to §117.203 revise §117.203(a)(4) by adding molten sulfur oxidation furnaces to the list of exemptions. A molten sulfur oxidation furnace produces sulfur dioxide for use in manufacturing sulfuric acid through the oxidation of molten sulfur. This addition is consistent with the existing exemptions for certain units which commingle fuel and process chemicals, such as sulfuric acid regeneration units. The changes to §117.203 also revise §117.203(a)(6) by adding the phrase "stationary internal combustion" to clarify that this exemption is not limited to gas-fired engines.

The changes to §117.205 revise §117.205(a) to specify that emission reduction credits available under §117.570, concerning Use of Emissions Credits for Compliance, may be used to comply with §117.205. The changes to §117.205 also abbreviate pound NO_x per million British thermal units as lb NO_x/MMBtu in §117.205(a)(1)(A) and (2)(A), and §117.205(b)(1)(A) and (7)(A) - (B). In addition, the changes to §117.205 replace the phrase "pursuant to" in §117.205(a)(1) and (3) with "in accordance with" for consistency with the agency's style guidelines.

The changes to §117.205 also delete a reference to §117.540 in §117.205(a)(3) because §117.540 is being repealed, as described later in this preamble.

The changes to §117.206, concerning Emission Specifications for Attainment Demonstrations, delete the alternate ESADs in §117.206(c)(18)(A) - (Q) which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC. Specifically, in January 2001, BCCA-AG and others filed suit against the commission challenging the December 6, 2000 SIP revision for HGA and five of the ten sets of rules associated with that SIP revision. As part of that lawsuit, the plaintiffs sought a temporary injunction to stay the effectiveness of these five sets of rules and for the commission to withdraw the SIP from EPA consideration. A hearing on this request was held before Judge Margaret Cooper, Travis County District Court, Texas, on May 14 - 18, 2001. Before that hearing was completed, an agreement in principle was reached to settle the lawsuit, and a Consent Order was entered by Judge Cooper which includes certain specific items included in the SIP revision and rules in Chapters 101 and 117 proposed by the commission on May 30, 2001 (see the June 15, 2001 issue of the *Texas Register* (26 TexReg 4380 and 4400, respectively)) and subsequently adopted on September 26, 2001 (see the October 12, 2001 issue of the *Texas Register* (26 TexReg 8073 and 8110, respectively)).

In the December 2000 adoption of the original ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of those ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. A detailed explanation of how the commission reached these conclusions is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524).

The September 26, 2001 adoption of revisions to Chapter 117 included changes to §117.206 which added ESADs in HGA for stationary diesel engines as a new §117.206(c)(9)(D). The justification for this change is described in detail in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8110).

The commission is proposing to delete the current ESADs of §117.206(c)(1) - (17) and replace them with the alternate ESADs of §117.206(c)(18)(A) - (Q) which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC.

For certain source categories, the alternate ESADs of §117.206(c)(18) are identical to the corresponding current ESADs of §117.206(c)(1) - (17). The specific categories are in the following rules: §115.206(c)(1)(C), (2)(B) and (C), (3), (4), (6), (7), (8)(C), (9)(A)(i) and (B) - (D), and (12) - (17). Although the implementation of the BCCA-AG's alternate ESADs would not result in more lenient ESADs for the source categories specified in §115.206(c)(1)(C), (2)(B) and (C), (3), (4), (6), (7), (8)(C), (9)(A)(i) and (B) - (D), and (12) - (17), the commission solicited comments on equitableness of these ESADs as compared to the proposed change of the ESADs for other source categories. These comments are addressed later in this preamble under the RESPONSE TO COMMENTS heading.

The changes to §117.206 also revise §117.206(c)(7) to clarify that the ESAD for oil-fired boilers applies not just to boilers firing oil, but to boilers firing any liquid fuel which does not cause the unit to fall under the hazardous waste-fired boilers and industrial furnaces (BIF unit) ESAD. This change is consistent with the current §117.206(c)(18)(G), and the commission's intent to make this change was discussed in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8137).

In addition, the changes to §117.206 revise §117.206(c)(9) to clarify that the emission specification for diesel engines is the lower of 11.0 grams per horsepower-hour (g/hp-hr) or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. This change is necessary to ensure that an inadvertent windfall is not created for existing diesel engines which emit less than 11.0 g/hp-hr.

The changes to §117.206 also revise §117.206(c)(17), which provides an ESAD for a unit with an annual capacity factor of 0.0383 or less, to specify that averaging may be used to determine eligibility for this ESAD. Specifically, the revisions state that for units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor is used to determine whether the unit is eligible for the ESAD of these paragraphs. The revisions further specify that for units placed into service after January 1, 1997, the annual capacity factor is calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of these paragraphs (using the same two consecutive years chosen for the activity level baseline), and that the five-year period begins at the end of the adjustment period as defined in 30 TAC §101.350, concerning Definitions.

In addition, the changes to §117.206 revise §117.206(e)(1) to establish a CO limit of 775 ppmv at 7.0% O_2, dry basis, for wood fuel-fired boilers or process heaters. This is consistent with the existing CO limit for wood fuel-fired boilers or process heaters in §117.205(f)(2), which was established based on CO and O_2 emissions data indicating that wood fuel-fired boilers or process heaters do not attain the 400 ppmv CO at 3.0% O_2 standard. (See the June 10, 1994 issue of the *Texas Register* (19 TexReg 4530)). The 775 ppmv CO at 7.0% O_2 standard (1,000 ppmv CO at 3.0% O_2) represents reasonably tuned performance for a wood-fired boiler.

The changes to §117.206 further revise §117.206(e)(2) by specifying the percent O_2 to which the existing ammonia limit of ten ppmv is to be corrected. The revisions follow the same convention used to correct the NO_x emission specifications for various units to a standard O_2 basis. Because the ammonia slip limit is intended to apply to units equipped with SCR, SNCR, or SCR/SNCR hybrids for NO_x control, the revisions to §117.206(e)(2) also clarify that the ammonia slip limit applies to units which inject urea or ammonia into the exhaust stream for NO_x control.

The changes to §117.206 also revise §117.206(h)(3) to specify that changes after December 31, 2000 to a unit subject to an ESAD in §117.206(c) (an "ESAD unit") which result in increased NO_x emissions from a unit not subject to an ESAD in §117.206(c) (a "non-ESAD unit"), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS or through stack testing, and a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made in accordance with 30 TAC §101.354, concerning Allowance Deductions. This is necessary to prevent circumvention due to the transfer of emissions from a unit under which these emissions would be controlled (i.e., a unit subject to an ESAD) to a unit that is not subject to the mass emissions cap and trade program (i.e., a unit without an ESAD) and therefore is uncontrolled. If a fuel or waste stream containing chemical-bound nitrogen was being directed to a non-ESAD unit on or before December 31, 2000, then any increase in the non-ESAD unit's NO_x emission rate that resulted after December 31, 2000 from increasing the amount of chemical-bound nitrogen directed to the non-ESAD unit is a change that would be subject to the requirement that the increase in NO_x emissions at the non-ESAD unit be determined using a CEMS or PEMS or through stack testing, with a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit made in accordance with the mass emissions cap and trade program.

In addition, the changes to §117.206 add a new §117.206(h)(4) which specifies that a source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of Chapter 117. The new §117.206(h)(4) further specifies that a source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of Chapter 117. This change, in conjunction with the corresponding new §117.475(g) described later in this preamble, is necessary to close a potential loophole for certain major sources. Currently, if a major source in HGA consists primarily of units which are not subject to an ESAD, includes one or more units for which an ESAD has been established, but is not subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, because the cumulative design capacity to emit of the units subject to ESADs is less than ten tons per year (tpy), it could be interpreted that this major NO_x emission source would not be required to make any emission reductions. It was never the commission's intention to exempt major NO_x emission sources which have a limited amount of affected units from reducing NO_x emissions. The change will ensure that such sources are subject to the same ESADs and the same emission reduction requirements as other major sources.

The changes to §117.206 also add a new §117.206(h)(5) which specifies that the low annual capacity factor ESAD available under §117.206(c)(17) for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. This change is necessary to ensure that reduced operation after December 31, 2000 cannot be used to qualify for a more lenient emission specification under §117.206(c)(17) than would otherwise apply to the unit.

Finally, the changes to §117.206 add a new §117.206(i)(3) to exclude firewater pumps used for emergency response training conducted in the months of April through October from the current §117.206(i), which prohibits stationary diesel and dual-fuel engines in HGA from being started or operated for testing or maintenance between the hours of 6:00 a.m. and noon. The change is necessary to minimize the potential for heat exhaustion or heat stroke due to the protective clothing worn by an in-house fire brigade during emergency response training.

The changes to §117.207, concerning Alternative Plant-wide Emission Specifications, delete extraneous parentheses in §117.207(b), abbreviate pound NO_x per million British thermal units as lb NO_x/MMBtu in §117.207(b)(1)(A), abbreviate parts per million by volume as ppmv in §117.207(b)(1)(A) and (3), abbreviate megawatt as MW in §117.207(g)(3), correct the type of brackets used in the equation for in-stack NO_x in the figure in §117.207(g)(3), and add "or" to §117.207(i)(1).

The changes to §117.207 also add a new §117.207(j) which specifies that after the applicable attainment demonstration SIP compliance date, the alternative plant-wide RACT emission specifications will no longer apply to equipment in HGA for which §117.206(c) has established a more stringent emission specification. This will avoid any potential conflicts of the RACT limits and the more stringent ESADs. For purposes of §117.207(j), the alternative plant-wide RACT emission specifications of §117.207 remain in effect until the emissions allocation for units under the HGA mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide RACT emission specifications of §117.207.

The changes to §117.213, concerning Continuous Demonstration of Compliance, revise §117.213(a)(1)(A) to specify that stationary gas turbines exempted under §117.205(h)(7) are subject to the totalizing fuel flow meter requirements. This revision is necessary because stationary gas turbines rated at 1.0 MW or greater were required to install totalizing fuel flow meters by November 15, 1999, but are exempt from the emission specifications of §117.205 under §117.205(h)(7). Consequently, the current wording of §117.213(a)(1)(A) inadvertently does not include stationary gas turbines in the 1.0 to 10.0 MW range. The adopted revision corrects this error.

The changes to §117.213 also revise §117.213(c)(1)(I) to specify that the owner or operator of fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents) in HGA shall monitor the stack exhaust flow rate with a flow meter using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A. This revision is necessary because the flow rate must be known in order to determine the mass emission rate.

In addition, the changes to §117.213 revise §117.213(e)(1)(B)(ii) to provide an alternative to the CEMS relative accuracy requirements of 40 CFR Part 60, Appendix B, Performance Specification 2, and revise §117.213(e)(1)(C) to specify that an annual relative accuracy test audit (RATA) is required if the owner or operator chooses the optional alternative relative accuracy requirement of §117.213(e)(1)(B)(ii). The revisions are necessary because 40 CFR Part 60 looks at relative accuracy in terms of percentage instead of an absolute value and was designed for much higher NO_x concentrations than the ESADs represent. Consequently, there is a potential to fail a RATA under 40 CFR Part 60 when a source is operating at very low NO_x concentrations (e.g., ten ppmv and below).

In addition, the changes to §117.213 revise §117.213(e)(1)(C) to clarify that the ongoing quality assurance procedures specified in that subparagraph are to commence after the date the CEMS is required to be certified, which for ESAD compliance is not a single final compliance date.

In addition, the changes to §117.213 revise §117.213(e)(3) and add a new §117.213(e)(4) to address the sharing of CEMS among more than one unit. The existing §117.213(e)(3) was developed for the NO_x RACT rules, with which affected units typically comply by meeting an individually enforceable limit, either directly through §117.205 or through averaging in accordance with §117.207. However, compliance with §117.206 and the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 in HGA is demonstrated through a limit on total annual tons of NO_x emitted to the atmosphere, such that it would be more effective for the NO_x CEMS requirements to be linked to stacks, rather than individual units. The new §117.213(e)(4) enables the sharing of CEMS in this manner in HGA. The new §117.213(e)(4) also specifies that all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack. This is necessary because under the mass emissions cap and trade program, all NO_x emissions are considered, including those from startup, shutdown, upset, and maintenance activities at affected units. The new §117.213(e)(4) further specifies that exhaust streams of units which vent to a common stack do not need to be analyzed separately. The changes to §117.213(e)(3)(B) clarify that for shared CEMS in BPA and DFW, the CEMS certification requirements must be met while the CEMS is operating in the time-shared mode.

The changes to §117.213 also add a new §117.213(e)(5) which provides an alternative to the CEMS requirements of 40 CFR Part 60 specified in §117.213(e)(1). The new §117.213(e)(5) provides that an owner or operator may choose to comply with the CEMS requirements of 40 CFR Part 75. The new paragraph is necessary because 40 CFR 60 looks at relative accuracy in terms of percentage instead of an absolute value, whereas 40 CFR Part 75 allows the use of an absolute difference. Because 40 CFR Part 60 was designed for much higher NO_x concentrations than the ESADs represent, there is a potential to fail a RATA under 40 CFR Part 60 when a source is operating at very low NO_x concentrations (e.g., ten ppmv and below). In addition, the existing §117.213(e)(4) has been renumbered as §117.213(e)(6) to accommodate the new §117.213(e)(4) and (5), and a reference to the new §117.213(e)(5) has been added to §117.213(e)(1) to facilitate the new §117.213(e)(5) described earlier in this paragraph.

In addition, the changes to §117.213 revise §117.213(f)(5)(A)(i)(I) and (C)(iii)(II) to provide an alternative to the CEMS relative accuracy requirements of 40 CFR Part 60, Appendix B, Performance Specification 2. The revisions are necessary because 40 CFR Part 60 looks at relative accuracy in terms of percentage instead of an absolute value and was designed for much higher NO_x concentrations than the ESADs represent. Consequently, there is a potential to fail a RATA under 40 CFR Part 60 when a source is operating at very low NO_x concentrations (e.g., ten ppmv and below).

The changes to §117.213 also add new §117.213(f)(5)(A)(ii)(IV) and (V) which revise the PEMS requirements by allowing temporary waivers of the r-correlation test based on certain cases. The new §117.213(f)(5)(A)(ii)(IV) allows a waiver from the statistical tests and default reference method standard deviation values for the F-test according to the "TNRCC PEMS Protocol Draft," May 16, 1994. The new §117.213(f)(5)(A)(ii)(V) provides a temporary waiver of the correlation analysis if the process design is such that it is technically impossible to vary the process to result in a concentration change sufficient to allow a successful correlation analysis statistical test, or if the data for a measured compound (e.g., NO_x, O_2) are determined to be autocorrelated according to the procedures of 40 CFR §75.41(b)(2), with the statistical test repeated at the next RATA to verify compliance with the correlation analysis statistical test requirement.

The changes to §117.213 also revise §117.213(g)(1)(C) to refer to "engines used exclusively in emergency situations" rather than the more specific phrase "gas-fired emergency generators." This change will exclude diesel-fired engines used exclusively in emergency situations from the biennial testing specified in §117.213(g)(1)(B) and will ensure that these engines will not have to be started for no reason other than to conduct this testing.

The changes to §117.213 also revise §117.213(i) to include a reference to §117.205(h)(9) which was inadvertently deleted in previous rulemaking. The change restores the NO_x RACT run time meter requirement for stationary gas turbines and engines which operate less than 850 hours per year, based on a rolling 12-month average, and is necessary to ensure compliance with the 850 hours per year limit. In addition, the changes to §117.213 correct a section title in §117.213(m).

The changes to §117.214, concerning Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration, add a new §117.214(a)(1)(D) which requires that ammonia monitoring be applied to units which inject urea or ammonia into the exhaust stream for NO_x control. The commission is adopting several options for ammonia slip monitoring in order to provide flexibility and minimize cost. The first option is to calculate the slip with a mass balance, as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of SCR. Because this option relies on process parameters routinely monitored in SCR systems, it is the least expensive procedure and is commonly specified in NSR permits. The permits typically require annual calibration of this method using a stack emission test for ammonia. The commission solicited comments on the usefulness of this stack test calibration based on recent experience; these comments are addressed later in this preamble under the RESPONSE TO COMMENTS heading. The second option is to monitor ammonia slip more directly by splitting the exhaust sample stream, converting the ammonia to NO in one stream with a thermal oxidizer, and measuring the ammonia as the difference between the converted and unconverted samples. This is the slip monitoring approach recommended by the Institute of Clean Air Companies at http://www.icac.com/noxgaswp.pdf. By alternately measuring streams, it may be feasible to monitor ammonia using an already required downstream NO_x analyzer, which would eliminate the cost of a separate analyzer. The third option is to conduct weekly ammonia sampling using stain tubes. This method has been specified in NSR permits. A fourth option is to use another method as approved by the executive director. A number of commercial methods of monitoring ammonia slip are described in the EPA's "Ammonia CEMS Background Report," June 14, 1993, available at http://www.epa.gov/ttn/emc/cem.html.

Control of the excess ammonia generation is a part of the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent, and a competently designed and operated post-combustion control system will minimize excess ammonia generation. Minimizing ammonia slip depends on designing the system such that injected ammonia is properly mixed and well distributed and such that the amount of catalyst (in the case of SCR) is sufficient to control both NO_x and ammonia to the desired levels. Nevertheless, there will be an increase in ammonia emissions due to ammonia slip associated with the use of post-combustion control technologies. It is desirable to minimize ammonia emissions due to the concern that significantly increased ammonia emissions will enhance formation of $PM_{2.5}$. Consequently, monitoring for ammonia emissions is necessary. The changes to §117.214 also renumber the existing §117.214(a)(1)(D) as §117.214(a)(1)(E) to accommodate the new §117.214(a)(1)(D).

In addition, the changes to §117.214 revise §117.214(b)(2) to specify that quarterly NO_x and CO emission checks are not required for engines equipped with CEMS or PEMS, since these quarterly checks are intended to be a substitute for CEMS or PEMS. The changes to §117.214 also add a new §117.214(b)(3) which specifies that each stationary internal combustion engine controlled with nonselective catalytic reduction (NSCR) 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. This change is necessary because an automatic AFR controller is necessary for NSCR to work reliably. In addition, the changes to §117.214 revise the catchline in §117.214(b) to specify "operating requirements" because the AFR requirement is more appropriately categorized as an operating requirement rather than a testing requirement.

In addition, the changes to §117.214 revise §117.214(c)(2)(C) to clarify that any retesting at a unit not equipped with a CEMS or PEMS establishes a new emission factor to be used to calculate actual emissions from the date of the retesting forward, with the previously determined emission factor used to calculate actual emissions for compliance with the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, until the date of the retesting. The changes to §117.214 also abbreviate continuous emissions monitoring system and predictive emissions monitoring system in §117.214(c)(2).

Finally, the changes to §117.214 add a new §117.214(c)(2)(D) which requires that all test reports be submitted to the executive director for review and approval within 60 days after completion of the testing. This is consistent with the existing requirements of Chapter 117 and is necessary to ensure the integrity and accuracy of testing.

The changes to §117.215, concerning Final Control Plan Procedures for Reasonably Available Control Technology, correct the reference in §117.215(a)(2)(E) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)). The changes to §117.215 also abbreviate million British thermal units per hour in §117.215(a)(6).

The changes to §117.216, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, correct the reference in §117.216(a)(1)(C) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)). In addition, the changes to §117.216 add a new §117.216(a)(1)(D) which references §117.207. This change is necessary because §117.207 is an option for compliance in BPA and DFW under §117.206(f)(1)(A). The changes to §117.216 also revise a reference from §117.206(a) and (b) to §117.206 and add a new §117.216(a)(1)(E) which references the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, and §117.210, concerning System Cap. These changes are necessary to ensure that sources in HGA submit the required information necessary to document compliance.

In addition, the changes to §117.216 revise §117.216(a)(4) by replacing a reference to the Austin office with a reference to the central office to avoid confusion with the Austin regional office. Finally, the changes to §117.216 add a new §117.216(a)(6) that specifies which information is to be submitted for EGFs subject to the system cap of §117.210. This is necessary to ensure that EGFs in HGA submit the required information necessary to document compliance (for example, the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates).

The changes to §117.219, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.219(a) by replacing a reference to §101.11 with a reference to §101.222. Section 101.222 was adopted in the September 6, 2002 issue of the *Texas Register* (27 TexReg 8499) and replaced §101.11.

The changes to §117.219 also revise §117.219(b)(1) to clarify that verbal notification of the date of any testing conducted under §117.211 must be made at least 15 days prior to such date followed by written notification within 15 days after testing is completed. Likewise, the changes to §117.219(c) clarify that results of testing conducted under §117.211 must be provided to the TCEQ central and regional offices and any local air pollution control agency having jurisdiction. This revision is necessary to ensure that any retesting conducted under §117.214(c)(2) is subject to the same notification and test result reporting requirements as the initial test.

The changes to §117.219 also revise §117.219(e) to replace the phrase "rich-burn" with "gas-fired" because this rule also applies to lean-burn engines. In addition, the changes to §117.219 replace a reference to quarterly reports in §117.219(e) with a reference to semiannual reports for consistency with references to these reports in §117.520(a)(2)(B) and elsewhere in §117.219(e). A semiannual reporting frequency is consistent with the reporting frequency specified for federal operating permits in 30 TAC §122.145, concerning Reporting Terms and Conditions. Affected owners and operators may maintain a quarterly schedule, if they prefer.

The changes to §117.221, concerning Alternative Case Specific Specifications, clarify that requests for alternate CO or ammonia limits are evaluated by the Engineering Services Team, Office of Compliance and Enforcement. It should be noted that the paragraphs (§117.106(d) and §117.206(e)) addressing pollutants which may increase as an incidental result of compliance with the NO_x limits, specifically, CO and ammonia, continue to be excluded from the SIP. The changes to §117.221 also revise a reference in §117.221(a)(2) from RACT to §117.205 or §117.206. This change is necessary because the ESADs of §117.206 go beyond RACT in some cases.

The changes to §117.221 also delete the reference to §50.39 and to filing a motion for reconsideration from §117.221(b) because §50.39 only applies to any application that is declared administratively complete before September 1, 1999. The reference to §50.139, which applies to any application that is declared administratively complete on or after September 1, 1999, is appropriate and has been retained.

The changes to §117.223, concerning Source Cap, abbreviate EPA in §117.223(a)(4) and revise §117.223(b)(1) to correct an inadvertent restriction on the use of the source cap. Specifically, the source cap in §117.223 is given as an option for compliance with the lean-burn engine emission specifications in §117.205(e) which are applicable in BPA. A company in BPA would like to use the source cap for their lean-burn engines, putting them into a cap with their boilers and heaters which are subject to the §117.205(a) - (d) RACT emission limits up until May 1, 2003, when the more stringent boiler and heater limits in §117.206 become applicable. However, the existing rule language seems to inadvertently prohibit them from combining the engines, boilers, and heaters into one source cap until May 1, 2003. The definition of H_i in the figure in §117.223(b)(1), variable (A), requires that the boilers and heaters complying with §117.205(a) - (d) use the original RACT heat input baseline within 1990 - 1993, and in variable (B) requires the lean burn engines and boilers and heaters under the ESAD to use the 1997 - 1999 baseline, while both §117.223(a) and (b) specify use of the same heat input baseline for all sources in the cap. For sources in BPA complying with the lean-burn engine emission specifications in §117.205(e), the revision to the definition of H_i in the figure in §117.223(b)(1), variable (B), will allow the owner or operator to combine the source cap with sources complying with §117.205(a) - (d) of this title, using the 1997 - 1999 heat input baseline described in the figure in §117.223(b)(1), variable (A), for the sources complying with §117.205(a) - (d). In addition, the revisions to the definition of R_i in the figure in §117.223(b)(1), variables (A)(ii) and (B)(ii), and to §117.223(c)(2) replace the phrase "pursuant to" with "in accordance with" for consistency with the agency's style guidelines. The changes to §117.223 also spell out Code of Federal Regulations in §117.223(c)(2).

In addition, the changes to §117.223 add a new §117.223(l) which specifies that after the applicable attainment demonstration SIP compliance date, the RACT source cap will no longer apply to equipment in HGA for which §117.206(c) has established a more stringent emission specification. This will avoid any potential conflicts of the RACT limits and the more stringent ESADs. For purposes of §117.223(l), the RACT source cap of §117.223 remains in effect until the emissions allocation for units under the HGA mass emissions cap are equal to or less than the allocation that would be calculated using the RACT source cap of §117.223. In addition, a reference to "system cap" is corrected to "source cap."

Subchapter C, Acid Manufacturing
Division 1, Adipic Acid Manufacturing
The changes to §117.301, concerning Applicability, revise the sentence structure for improved readability and revise "undesignated head" to "division" in response to revised *Texas Register* rules (see the February 13, 1998 issue of the *Texas Register* (23 TexReg 1289)).

The change to §117.309, concerning Control Plan Procedures, revises "undesignated head" to "division" in response to revised *Texas Register* rules.

The change to §117.311, concerning Initial Demonstration of Compliance, replaces a reference to "the effective date of this rule" in §117.311(d) with the actual date (June 23, 1994).

The changes to §117.313, concerning Continuous Demonstration of Compliance, update the reference to the PEMS requirements of §117.213 due to a recent renumbering of this section; revise the sentence structure for improved readability; revise "undesignated head" to "division" in response to revised *Texas Register* rules; and replace "Texas Natural Resource Conservation Commission (commission)" with "commission" because the agency's name was recently changed to "Texas Commission on Environmental Quality" in accordance with House Bill 2912, Article 18, 77th Legislature, 2001.

The changes to §117.319, concerning Notification, Recordkeeping, and Reporting Requirements, revise references to the TNRCC and the EPA for consistency with the agency's style guidelines. The changes to §117.319 also revise the record retention time specified in recordkeeping, §117.319(d), from two years to five years for consistency. The sources subject to Chapter 117 are also subject to FCAA, Title V permit requirements, which specify a five-year period for retention of compliance records.

The changes to §117.321, concerning Alternative Case Specific Specifications, revise a reference to the EPA for consistency with the agency's style guidelines; change a reference from RACT to the specific section (§117.305); revise “undesignated head” to “division” in response to revised *Texas Register* rules; and replace a reference to §103.71, concerning Request for Action by the Commission (which has been repealed), with a reference to §50.139, concerning Motion to Overturn Executive Director’s Decision.

Subchapter C, Acid Manufacturing
Division 2, Nitric Acid Manufacturing - Ozone Nonattainment Areas
The changes to §117.401, concerning Applicability, revise the sentence structure for improved readability; revise “undesignated head” to “division” in response to revised *Texas Register* rules; and correct a reference to the title of the division.

The changes to §117.409, concerning Control Plan Procedures, revise “undesignated head” to “division” in response to revised *Texas Register* rules and correct a reference to the title of the division.

The change to §117.411, concerning Initial Demonstration of Compliance, replaces a reference to “the effective date of this rule” in §117.411(d) with the actual date (June 23, 1994).

The changes to §117.413, concerning Continuous Demonstration of Compliance, update the reference to the PEMS requirements of §117.213 due to a recent renumbering of this section; revise the sentence structure for improved readability; revise “undesignated head” to “division” in response to revised *Texas Register* rules; correct a reference to the title of the division; and replace “Texas Natural Resource Conservation Commission (commission)” with “commission” due to the recent change in the agency's name.

The changes to §117.419, concerning Notification, Recordkeeping, and Reporting Requirements, revise references to the TNRCC and the EPA for consistency with the agency's style guidelines. The changes to §117.419 also delete two section titles in §117.419(b) because the titles are included earlier in this section. In addition, the changes to §117.419 revise the record retention time specified in recordkeeping, §117.419(d), from two years to five years for consistency. The sources subject to Chapter 117 are also subject to FCAA, Title V permit requirements, which specify a five-year period for retention of compliance records.

The changes to §117.421, concerning Alternative Case Specific Specifications, revise a reference to the EPA for consistency with the agency's style guidelines; change a reference from RACT to the specific section (§117.405); revise “undesignated head” to “division” in response to revised *Texas Register* rules; and replace a reference to §103.71, concerning Request for Action by the Commission (which has been repealed), with a reference to §50.139, concerning Motion to Overturn Executive Director’s Decision.

Subchapter D, Small Combustion Sources
Division 1, Water Heaters, Small Boilers, and Process Heaters
The changes to §117.463, concerning Exemptions, add exemptions for manufacturers and distributors of water heaters, small boilers, and process heaters which exceed the emission limits of §117.465, concerning Emission Specifications, but which are intended for shipment and use outside of Texas. The new exemptions are necessary because some Texas manufacturers also market their products outside of Texas. Similarly, some manufacturers may produce units that exceed the emission limits of §117.465 and ship them to a Texas distribution center which then ships them outside of Texas.

The change to §117.465, concerning Emission Specifications, corrects a typographical error in §117.465(4)(B) by deleting "per hour."

The change to §117.467, concerning Certification Requirements, corrects a reference to the South Coast Air Quality Management District because the rule currently lacks "Quality."

Subchapter D, Small Combustion Sources
Division 2, Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources
The changes to §117.473, concerning Exemptions, revise §117.473(2)(E), (H)(ii), and (I)(ii) by deleting "effective" before the date of the revisions to 40 CFR §60.15 (December 16, 1975) because this date is the date of publication in the *Federal Register*, rather than the effective date of 40 CFR §60.15.

The changes to §117.475, concerning Emission Specifications, add a new §117.475(c)(1)(B) which specifies an ESAD of 0.072 lb/MMBtu heat input (or alternatively, 60 ppmv at 3.0% O_2, dry basis) for liquid-fired boilers and process heaters, and clarify that the ESAD of 0.036 lb/MMBtu heat input (or 30 ppmv at 3.0% O_2, dry basis) is applicable to gas-fired units.

The changes to §117.475 also revise §117.475(c)(4)(A) to clarify that the emission specification for diesel engines is the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. This change is necessary to ensure that an inadvertent windfall is not created for existing diesel engines which emit less than 11.0 g/hp-hr.

The changes to §117.475 further revise §117.475(c)(4)(B) because ESADs for stationary diesel engines rated at less than 50 horsepower (hp) were inadvertently included for minor sources in the existing §117.475(c)(4)(B)(i) - (iii). Because §117.473(a)(2)(A) exempts engines rated at less than 50 hp, these ESADs are superfluous. Therefore, the existing §117.475(c)(4)(B)(i) - (iii) has been deleted, and the existing §117.475(c)(4)(B)(iv) - (ix) has been renumbered as §117.475(c)(4)(B)(i) - (vi).

In addition, the changes to §117.475 revise §117.475(c)(6), which provides an ESAD for a unit with an annual capacity factor of 0.0383 or less, to specify that averaging may be used to determine eligibility for this ESAD. Specifically, the revisions state that for units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor is used to determine whether the unit is eligible for the ESAD of this paragraph. The revisions further specify that for units placed into service after January 1, 1997, the annual capacity factor is calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph (using the same two consecutive years chosen for the activity level baseline), and that the five-year period begins at the end of the adjustment period as defined in §101.350.

The changes to §117.475 also revise §117.475(f) to specify that changes after December 31, 2000 to a unit subject to an ESAD in §117.475(c) (an "ESAD unit") which result in increased NO_x emissions from a unit not subject to an ESAD in §117.206(c) (a "non-ESAD unit"), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS or through stack testing, and a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made as specified in §101.354. This is necessary to prevent circumvention due to the transfer of emissions from a unit under which these emissions would be controlled (i.e., a unit subject to an ESAD) to a non-ESAD unit which consequently is uncontrolled. If a fuel or waste stream containing chemical-bound nitrogen was being directed to a non-ESAD unit on or before December 31, 2000, then any increase in the non-ESAD unit's NO_x emission rate that resulted after December 31, 2000 from increasing the amount of chemical-bound nitrogen directed to the non-ESAD unit is a change that would be subject to the requirement that the increase in NO_x emissions at the non-ESAD unit be determined using a CEMS or PEMS or through stack testing, with a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit made in accordance with the mass emissions cap and trade program.

In addition, the changes to §117.475 add a new §117.475(g) which specifies that a source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of Chapter 117. The new §117.475(g) further specifies that a source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of Chapter 117. This change, in conjunction with the corresponding change to §117.206(h)(4) described earlier in this preamble, is necessary to close a potential loophole for certain major sources. Currently, if a major source in HGA consists primarily of units which are not subject to an ESAD, includes one or more units for which an ESAD has been established, but is not subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, because the cumulative design capacity to emit of the units subject to ESADs is less than ten tpy, it could be interpreted that this major NO_x emission source would not be required to make any emission reductions. It was never the commission's intention to exempt major NO_x emission sources which have a limited amount of affected units from reducing NO_x emissions. The change will ensure that such sources are subject to the same ESADs and the same emission reduction requirements as other major sources.

The changes to §117.475 also add a new §117.475(h) which specifies that the low annual capacity factor ESAD available under §117.475(c)(6) for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. This change is necessary to ensure that reduced operation after December 31, 2000 cannot be used to qualify for a more lenient emission specification under §117.475(c)(6) than would otherwise apply to the unit.

Finally, the changes to §117.475 add a new §117.475(i) which specifies ammonia and CO limits. The new limits are necessary to prevent large increases in ammonia and CO emissions concurrent with the installation of NO_x controls, and represent a maximum rate under good engineering practice. Testing for these pollutants is already required under §117.479(e)(1) and (2). The commission is excluding these related pollutant limits of §117.475(i) from the SIP in order to simplify the approval process for alternative emission specifications under the new §117.481, concerning Alternative Case Specific Specifications. This step will eliminate the need for case specific SIP revisions by the EPA to complete the approval of an alternate CO or ammonia limit. Because the ammonia slip limit is intended to apply to units equipped with SCR, SNCR, or SCR/SNCR hybrids for NO_x control, the new §117.475(i)(2) also specifies that the ammonia slip limit applies to units which inject urea or ammonia into the exhaust stream for NO_x control.

The change to §117.478, concerning Operating Requirements, adds a new §117.478(c)(3) to exclude firewater pumps used for emergency response training conducted in the months of April through October from the current §117.478(c), which prohibits stationary diesel and dual-fuel engines in HGA from being started or operated for testing or maintenance between the hours of 6:00 a.m. and noon. The change is necessary to minimize the potential for heat exhaustion or heat stroke due to the protective clothing worn by an in-house fire brigade during emergency response training.

The changes to §117.479, concerning Monitoring, Recordkeeping, and Reporting Requirements, revise the totalizing fuel flow meter and recordkeeping requirements of §117.479(a)(1) and (g) to include references to §117.473(b). These revisions are necessary for the owner or operator of boilers and process heaters claimed exempt under §117.473(b) to be able to demonstrate compliance with the annual heat input limits.

The changes to §117.479 also add a new §117.479(e)(2) which requires that ammonia monitoring be applied to units which inject urea or ammonia into the exhaust stream for NO_x control. The commission is adopting several options for ammonia slip monitoring in order to provide flexibility and minimize cost. The first option is to calculate the slip with a mass balance, as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of SCR. Because this option relies on process parameters routinely monitored in SCR systems, it is the least expensive procedure and is commonly specified in NSR permits. The permits typically require annual calibration of this method using a stack emission test for ammonia. The commission solicited comments on the usefulness of this stack test calibration based on recent experience; these comments are addressed later in this preamble under the RESPONSE TO COMMENTS heading. The second option is to monitor ammonia slip more directly by splitting the exhaust sample stream, converting the ammonia to NO in one stream with a thermal oxidizer, and measuring the ammonia as the difference between the converted and unconverted samples. This is the slip monitoring approach recommended by the Institute of Clean Air Companies at http://www.icac.com/noxgaswp.pdf. By alternately measuring streams, it may be feasible to monitor ammonia using an already required downstream NO_x analyzer, which would eliminate the cost of a separate analyzer. The third option is to conduct weekly ammonia sampling using stain tubes. This method has been specified in NSR permits. A fourth option is to use another method as approved by the executive director. A number of commercial methods of monitoring ammonia slip are described in the EPA's “Ammonia CEMS Background Report,” June 14, 1993, available at http://www.epa.gov/ttn/emc/cem.html.

Control of the excess ammonia generation is a part of the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent, and a competently designed and operated post-combustion control system will minimize excess ammonia generation. Minimizing ammonia slip depends on designing the system such that injected ammonia is properly mixed and well distributed and such that the amount of catalyst (in the case of SCR) is sufficient to control both NO_x and ammonia to the desired levels. Nevertheless, there will be an increase in ammonia emissions due to ammonia slip associated with the use of post-combustion control technologies. It is desirable to minimize ammonia emissions due to the concern that significantly increased ammonia emissions will enhance formation of $PM_{2.5}$. Consequently, monitoring for ammonia emissions is necessary. The changes to §117.479 also renumber the existing §117.479(e)(2) as §117.479(e)(3) to accommodate the new §117.479(e)(2).

In addition, the changes to §117.479 revise §117.479(e)(7)(C) to clarify that any retesting at a unit not equipped with a CEMS or PEMS establishes a new emission factor to be used to calculate actual emissions from the date of the retesting forward, with the previously determined emission factor used to calculate actual emissions for compliance with the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 until the date of the retesting.

The changes to §117.479 add a new §117.479(e)(9) which requires that all test reports be submitted to the executive director for review and approval within 60 days after completion of the testing. This is consistent with the existing requirements of Chapter 117 and is necessary to ensure the integrity and accuracy of testing. Finally, the changes to §117.479 abbreviate carbon monoxide as CO in §117.479(g)(4).

The new §117.481 allows alternative emission specifications to be established on a case-specific basis for CO and ammonia. The commission is excluding these related pollutant limits from the SIP in order to simplify the approval process for alternative emission specifications. This step will eliminate the need for case-specific SIP revisions by the EPA to complete the approval of an alternate CO or ammonia limit.

Subchapter E, Administrative Provisions

The changes to §117.510, concerning Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas, add new §117.510(a)(2)(C) and (b)(2)(A)(iii) which specify a May 1, 2003 compliance date for installation of CEMS or PEMS on previously exempt units in BPA and DFW and completion of applicable CEMS or PEMS evaluations and quality assurance procedures specified in §117.113. The previously exempt units include utility boilers which are not subject to 40 CFR Part 75 NO_x monitoring (i.e., those rated at up to 25 MW) and utility boilers claimed exempt from NO_x RACT using the low annual capacity factor exemption of §117.103(a)(2), concerning Exemptions. A CEMS or PEMS is necessary for these units to be able to demonstrate compliance with §117.106(a) and (b).

In addition, the changes to §117.510 revise §117.510(c)(2)(A)(i) to specify that an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005.

The changes to §117.510 also delete §117.510(c)(2)(E) because the deletion of the alternate ESADs in §117.106(c)(5) makes §117.510(c)(2)(E) unnecessary. Because alternate ESADs are being implemented through relocation to §117.106(c)(1) - (3), the current language of §117.510(c)(2)(E)(i) is replacing the current language of §117.510(c)(2)(B)(iii)(I). Similarly, the current language of §117.510(c)(2)(E)(ii) is relocated to §117.510(c)(2)(B)(iii)(III). The new §117.510(c)(2)(B)(iii)(II) requires submission, by March 31, 2004, of the information specified in §117.116, which, as described earlier in this preamble, is necessary to document compliance. This information would include, for example, the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates.

The changes to §117.512, concerning Compliance Schedule for Utility Electric Generation in East and Central Texas, specify how compliance with the regional electric utility requirements is determined in the remainder of the calendar year following the final compliance date (either May 1, 2003 or May 1, 2005). Because compliance with the NO_x emission specifications and optional system cap is on an annual basis, the changes specify that the first year's compliance is determined using the period of May 1 through April 30, with compliance for each subsequent annual period on a calendar year basis.

The changes to §117.512 also specify that the updated final control plan required by §117.145, concerning Final Control Plan Procedures, shall be submitted no later than one month after the end of the first year's compliance period, and by January 31 of the next calendar year. These changes are consistent with the intent of the current rule language. In addition, the changes to §117.512 add a new §117.512(1)(C) which specifies a May 1, 2005 compliance date for electric utilities in east and central Texas to meet the ammonia limit of §117.135(2) described earlier in this preamble.

The changes to §117.520, concerning Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas, revise §117.520(c)(2)(A)(i) to specify that an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005.

In addition, the changes to §117.520 revise §117.520(c)(2)(A)(ii)(I) to clarify the commission's intent that the requirement in §117.211(c) for CEMS or PEMS to be operational before stack testing does not apply to a stack test conducted before March 31, 2005 on a unit not equipped with CEMS or PEMS for which CEMS or PEMS must be installed no later than March 31, 2005. In addition, the commission revised §117.520(c)(2)(A)(ii)(II) to clarify that if the monitoring system installation is deferred until March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures still must be submitted by that date.

The changes to §117.520 also revise the system cap compliance schedule for non-utility EGFs in §117.520(c)(2)(B)(iii) by deleting the intermediate compliance dates. The commission adopts this revision to eliminate the unnecessarily complicated schedule and to allow the affected industries more options for planning and implementing incremental reductions in emissions. The amendment would not affect the March 31, 2007 final compliance date nor would it increase final emission rates, and would still achieve the final emission reductions as required by the SIP.

In addition, the changes to §117.520 delete §117.520(c)(2)(C) because the deletion of the alternate ESADs in §117.206(c)(18) makes §117.520(c)(2)(C) unnecessary. Subsequent subparagraphs are relettered due to the deletion of §117.520(c)(2)(C).

The changes to §117.520 also add a new §117.520(c)(2)(F) which specifies that March 31, 2005 is the default compliance date for HGA attainment demonstration requirements that are not explicitly addressed elsewhere in §117.520(c)(2), such as the quarterly engine checks required by §117.214(b)(2).

The changes to §117.534, concerning Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources, revise §117.534(1)(B)(i) and (2)(B)(i) to clarify the commission's intent that the requirement in §117.479(e)(6) for CEMS or PEMS to be operational before stack testing does not apply to a stack test conducted before March 31, 2005 on a unit not equipped with CEMS or PEMS for which CEMS or PEMS must be installed no later than March 31, 2005. In addition, the commission revised §117.534(1)(B)(ii) and (2)(B)(ii) to clarify that if the monitoring system installation is deferred until March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures still must be submitted by that date.

The changes to §117.534 also add a new §117.534(1)(F) which specifies that March 31, 2005 is the default compliance date for HGA attainment demonstration requirements that are not explicitly addressed elsewhere in §117.534, such as the quarterly engine checks required by §117.478(b)(5).

In addition, the changes to §117.534 revise §117.534(2)(A) to specify that an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005.

The changes to §117.534 revise §117.534(2)(B)(i) to clarify the commission's intent that the requirement in §117.479(e)(6) for CEMS or PEMS to be operational before stack testing does not apply to a stack test conducted before March 31, 2005 on a unit not equipped with CEMS or PEMS for which CEMS or PEMS must be installed no later than March 31, 2005. In addition, the commission revised §117.534(2)(B)(ii) to clarify that if the monitoring system installation is deferred until March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures still must be submitted by that date.

The changes to §117.534 also switch the order of the existing §117.534(2)(C) and (D) for consistency with §117.534(1) and to make the order more logical.

Section 117.540, concerning Phased Reasonably Available Control Technology (RACT), is repealed because this section has been made obsolete by the passing of the March 31, 2001 final compliance date for RACT in DFW specified in §117.510(b)(1).

Section 117.560, concerning Recission, is repealed because this section has been made obsolete by determinations that NO_x reductions are necessary for attainment of the ozone standard. The FCAA, 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 §7511a(f) NO_x measures would contribute to ozone attainment.

On April 16, 1999, EPA published notice in the *Federal Register* (64 FR 18864) that in order for BPA to take advantage of a policy which allows consideration of the effect of transport of ozone or its precursors from an upwind area, 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. The commission met the "expeditious attainment" requirement of EPA's policy by providing for additional NO_x reductions in BPA through adoption of lean-burn engine NO_x rules on October 27, 1999. Commission staff conducted modeling for an ozone episode showing transport from HGA to BPA, as well as another ozone episode in which BPA's local emission contributions predominate in the formation of ozone, showing the need for more NO_x reductions in BPA in order for the area to attain the one-hour ozone standard. The commission adopted additional NO_x rules on April 19, 2000 in order for BPA to attain under these local contributions conditions.

On June 21, 1999, the EPA rescinded a 42 USC, §7511a(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. Similarly, the §7511a(f) exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under §7511a(f) was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the commission has made determinations for BPA, DFW, and HGA that NO_x reductions are necessary for attainment of the ozone standard in these ozone nonattainment areas, thereby rendering §117.560 obsolete.

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 HGA ozone nonattainment area. 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 (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.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION
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. A "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 and revisions to the SIP amend requirements to achieve the intended NO_x emission reductions of the program. Specifically, the amendments to Chapter 117 will require emission reductions, and, for some facilities, revise the ESADs, from electric utility boilers and stationary gas turbines; ICI boilers and stationary gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary internal combustion engines; fluid catalytic cracking units (including catalyst regenerators and CO boilers and furnaces); pulping liquor recovery furnaces; lime kilns; lightweight aggregate (LWA) kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators; and BIF units in the HGA ozone nonattainment area. 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, petrochemical plants, refineries, and other industrial, commercial, or institutional groups, and each group could be considered a sector of the economy in a sector of the state. This is based on the analysis provided in the rule proposal preamble, including the discussion in the PUBLIC BENEFITS AND COSTS section of the proposal which was published in the June 21, 2002 issue of the *Texas Register* (27 TexReg 5454) and in preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524). In addition, the amendments add ammonia emission specifications for electric generating facilities located in 31 attainment counties of east and central Texas. The remaining amendments in this rulemaking are intended to correct typographical errors, update cross-references, clarify ambiguous language, add flexibility and delete obsolete language, and these amendments are not expected to 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 do not meet any of the four applicability criteria for requiring a regulatory analysis of a "major environmental rule" as defined in the Texas Government Code. 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. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. While 42 USC, §7410, does not require specific programs, methods, or reductions in order to meet the standard, SIPs must include "enforceable emission limitations and other control measures, means or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance as may be necessary or appropriate to meet the applicable requirements of this chapter," (meaning Chapter 85, Air Pollution Prevention and Control). It is true that the FCAA does require some specific measures for SIP purposes, such as the inspection and maintenance program, but those programs are the exception, not the rule, in the SIP structure of the FCAA. The provisions of the FCAA recognize that states are in the best position to determine what programs and controls are necessary or appropriate in order to meet the NAAQS. This flexibility allows states, affected industry, and the public, to collaborate on the best methods for attaining the NAAQS for the specific regions in the state. Even though the FCAA allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of 42 USC, §7410. Thus, while specific measures are not generally required, the emission reductions are required. States are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule.

The requirement to provide a fiscal analysis of proposed regulations in the Texas Government Code were amended by Senate Bill (SB) 633 during the 75th Legislative Session. The intent of SB 633 was to require agencies to conduct an regulatory impact analysis (RIA) 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 law, federal law, or a delegated federal program, or are 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. As discussed earlier in this preamble, the FCAA does not require specific programs, methods, or reductions in order to meet the NAAQS; thus, states must develop programs for each nonattainment area to ensure that area will meet the attainment deadlines. Because of the ongoing need to address nonattainment issues, the commission routinely proposes and 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 RIA 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 only to require the full RIA 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. For these reasons, rules adopted for inclusion in the SIP fall under the exception in Texas Government Code, §2001.0225(a), because they are specifically required by federal law.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The adopted rules will be submitted to the EPA as measures in the federally approved SIP. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f) exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App.–Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App.–Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the 76th legislature (1999). In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified, in Texas Government Code, §2001.035, that state agencies are required to meet certain sections of the APA against the standard of "substantial compliance." The legislature specifically identified Texas Government Code, §2001.0225 as subject to this standard. The commission has more than substantially complied with the requirements of §2001.0225.

As discussed earlier in this preamble, this rulemaking implements requirements of the FCAA. There is no contract or delegation agreement that covers the topic that is the subject of this rulemaking. Therefore, the adopted rules do not exceed a standard set by federal law, exceed an express requirement of state law, exceed a requirement of a delegation agreement, nor are adopted solely under the general powers of the agency. In addition, the rules are adopted under the Texas Health and Safety Code (THSC), Texas Clean Air Act (TCAA), §§382.011, 382.012, 382.014, 382.016, 382.017, 382.021 and 382.051(d). Comments regarding the draft RIA determination are addressed later in this preamble under the RESPONSE TO COMMENTS heading.

TAKINGS IMPACT ASSESSMENT

The commission completed a takings impact analysis for the adopted rules under Texas Government Code, §2007.043. The specific purposes of these amendments are to achieve reductions in NO_x emissions and ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone, as well as to improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, and deleting obsolete language. Certain sources located in HGA 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.

Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to these adopted rules, because they are reasonably taken to fulfill an obligation mandated by federal law. The NO_x emission limitations and control requirements within this rulemaking were developed in order to meet the NAAQS for ozone set by the EPA under 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. Under 42 USC,

§7410, and related provisions, states must submit, for approval by the EPA, SIPs that provide for the attainment and maintenance of NAAQS through control programs directed to sources of the pollutants involved. Therefore, one purpose of this rulemaking action is to meet the air quality standards established under federal law as NAAQS. Attainment of the ozone standard will eventually require substantial NO_x reductions as well as reductions of highly-reactive VOC emissions. Any NO_x reductions resulting from the current rulemaking are no greater than what 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, Texas Government Code, §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. This action is taken in response to the HGA area 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 ozone levels in the HGA nonattainment area, as well as minimizing ammonia emissions due to the concern that significantly increased ammonia emissions will enhance formation of $PM_{2.5}$, which is a pollutant subject to a NAAQS. The amendments add ammonia emission specifications for electric generating facilities located in 31 attainment counties of east and central Texas. Control of the excess ammonia generation is a part of the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent, and a competently designed and operated post-combustion control system will minimize excess ammonia generation. It is desirable to minimize ammonia emissions due to the concern that significantly increased ammonia emissions will enhance formation of $PM_{2.5}$. Consequently, these adopted rules meet the exemption in §2007.003(b)(13). This rulemaking action therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons, the adopted rules do not constitute a takings under Chapter 2007.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission reviewed the rulemaking and found that it is a rulemaking identified in Coastal Coordination Act Implementation Rules, 31 TAC §505.11, or will affect an action/authorization identified in Coastal Coordination Act Implementation Rules, 31 TAC §505.11, and therefore will require that applicable goals and policies of the Coastal Management Program (CMP) be considered during the rulemaking process.

The commission reviewed this action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that the action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and ozone levels will be reduced as a result of these rules. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations in 40 CFR, to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action complies with 40 CFR. Therefore, in compliance with 31 TAC §505.22(e), this rulemaking action is consistent with CMP goals and policies. No comments were received during the comment period regarding the CMP consistency review.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMIT PROGRAM
Chapter 117 is an applicable requirement under 30 TAC Chapter 122; therefore, owners or operators subject to the Federal Operating Permit Program must, consistent with the revision process in Chapter 122, revise their operating permits to include the revised Chapter 117 requirements for each emission unit at their sites affected by the revisions to Chapter 117.

PUBLIC COMMENT
The commission held public hearings on this proposal at the following locations: July 18, 2002, in Austin; July 22, 2002 in Houston and Channelview; and August 6, 2002 in Houston. The comment period was originally scheduled to close on July 22, 2002, but was extended until 5:00 p.m. on August 6, 2002. (See the July 12, 2002 issue of the *Texas Register* (27 TexReg 6450)).

Thirty-two commenters submitted testimony on the proposal. Kaneka Texas Corporation (Kaneka) supported the proposed revisions to Chapter 117. AES Deepwater, Inc. (AES); Air Products, L.P. (Air Products); Association of Electric Companies of Texas, Inc. (AECT); BakerBotts L.L.P. on behalf of BCCA-AG (BCCA-AG); BASF; Bracewell and Patterson, L.L.P. on behalf of Louisiana-Pacific Corporation (Louisiana-Pacific); BP Products North America Inc. (BP); Chevron Phillips Chemical Company LP (Chevron); City of Austin Electric Utility Department d.b.a. Austin Energy (Austin Energy); City Public Service of San Antonio (CPS); Dow Chemical Company (Dow); DuPont; Environmental Defense (ED); EPA; Ethyl Corporation - Houston Plant (Ethyl); Galveston-Houston Association for Smog Prevention (GHASP); Goodyear Tire and Rubber Company - Houston Chemical Plant (Goodyear-Houston); Greater Houston Partnership; Jenkens and Gilchrist on behalf of TXI Operations, LP (TXI); Lyondell Chemical Company (Lyondell); Mothers for Clean Air (MfCA); National Aeronautics and Space Administration (NASA); Pavilion Technologies, Inc. (Pavilion); Phillips Petroleum Company (Phillips); Reliant Energy, Incorporated (Reliant); Shrader Engineering Co., Inc. (Shrader); Sierra Club - Houston Regional Group (Sierra-Houston); Sierra Club - Lone Star Chapter (Sierra-Lone Star); Texas Chemical Council (TCC); Texas Industry Project (TIP); Texas Oil and Gas Association (TxOGA); TXU Business Services (TXU); and Waid and Associates on behalf of Houston Marine Services (Houston Marine) supported the proposed revisions but suggested changes or clarifications.

GHASP supported the comments submitted by ED. Air Products, OxyChem, Sierra-Lone Star, and Valero did not have any Chapter 117 comments of their own, but supported the comments of groups that did. Sierra-Lone Star supported the comments submitted by ED, GHASP, and Sierra-Houston. Air Products supported the comments submitted by BCCA-AG and TCC. Chevron, Dow, OxyChem, and Valero supported the comments submitted by BCCA-AG and TCC. BP and DuPont supported the comments submitted by TCC. ExxonMobil and Phillips supported the comments submitted by BCCA-AG, TCC, and TxOGA.

RESPONSE TO COMMENTS

GENERAL COMMENTS

Ethyl stated that the proposed regulations and supporting documents are lengthy and that there was insufficient time to read them, evaluate them, gather information, and develop substantial comments with supportive documentation to oppose portions of the proposals.

Many of the supporting documents were posted on the commission's website for months before the rule revisions were proposed. In addition, the comment period was extended from July 22, 2002 to August 6, 2002. (See the July 12, 2002 issue of the *Texas Register* (27 TexReg 6450)). Any additional extensions of the comment period would not allow commission staff sufficient time to review and respond to the comments.

TXI noted that the commission used the 1997 emissions inventory as the baseline for the ESADs which were adopted in December 2000. TXI stated that for the emission rate of 1.0886 lb NO_x/ton of product in its 1997 emissions inventory, TXI had reported the NO_x emissions as NO, calculating the emissions on the basis of a 1992 stack test conducted using EPA test methods. TXI stated that this emission rate was calculated using the molecular weight of NO (i.e., 30), not nitrogen dioxide (NO_2) (i.e., 46), and that the emission rate calculated with NO_x, considered to be the sum of NO and NO_2, collectively expressed as NO_2, is 46/30 x 1.0886 = 1.669 lb NO_x/ton of product.

TXI commented that §117.10 defines "nitrogen oxides (NO_x)" as "the sum of the nitric oxide and nitrogen dioxide in the flue gas or emission point, *collectively expressed as nitrogen dioxide*." (TXI's emphasis supplied). TXI stated that Chapter 101 does not define "nitrogen oxides (NO_x)." TXI stated that the Emissions Inventory Questionnaire packages made available to the regulated community in 1997, 1998, and 1999 also did not contain a definition of "NO_x" but instead referred to "nitrogen oxides (NO_x)." As an example, TXI referenced the 1997 Emissions Inventory Questionnaire package at pages I-2, 3, and 42. TXI further stated that the Emissions Inventory Questionnaire packages defined "emissions" as "air contaminants generated by a facility" and "contaminants" as "a substance emitted into air" and asserted that a regulated company preparing an emissions inventory would reasonably believe, based on applicable rules and emissions inventory instructions made available by the commission, that it was supposed to report the quantity of nitrogen oxides being emitted from its facility into the air.

TXI stated that at its LWA kilns, 95% or more of the NO_x emitted into the air from these kilns is in the form of NO, rather than NO_2, and that consequently TXI reported its NO_x emissions as NO, calculating the emissions on the basis of the 1.0886 lb NO_x/ton of product emission rate. TXI stated that in 2000, it performed another stack test at its LWA plant which demonstrated a NO_x emission rate of 1.78 lbs/ton, expressed as NO_2. TXI stated that this rate compares favorably to the 1992 stack test result when expressed as NO_2. In summary, TXI stated that its 1997 baseline should be 1.669 lb NO_x/ton of product, not the 1.0886 lb NO_x/ton of product it reported.

The commission notes that §101.1 states that "unless specifically defined in the TCAA or in the rules of the commission, the terms used by the commission have the meanings commonly ascribed to them in the field of air pollution control." The definition of "nitrogen oxides (NO_x)" in §117.10

is consistent with the meaning commonly ascribed to this term in the field of air pollution control as well as state and federal air quality rules. In addition, the commission clarifies that until a definition of "nitrogen oxides (NO_x)" is added to Chapter 101, the existing definition in §117.10 is used for all commission air quality rules which include references to "nitrogen oxides" and/or "NO_x."

The Emissions Inventory Questionnaire packages and guidance do not attempt to define individual pollutants where universal usage is presumed. This is the case for NO_x where EPA guidance and general usage by the air pollution control community has expressed NO_x as NO_2 for decades. The universal convention of expressing NO_x emissions using the molecular weight of NO_2 is based on the fact that all emissions of NO are rapidly converted to NO_2 when released into the atmosphere. In the early days of addressing NO_x under the FCAA, EPA determined that NO_x should be expressed as NO_2. See *Air Quality Criteria for Oxides of Nitrogen*, (EPA-600/8-82-026, 1982) which addresses the reaction of NO to NO_2 after it is released into the atmosphere. It states "within or a few exit diameters downwind of a source such as a stack of a power plant . . . the relatively high NO concentrations which may be present can produce NO_2 in significant amounts." The thermodynamics of the reaction indicate that this conversion is extremely fast, limited only by the absence of oxygen, and occurs long before the pollutant crosses a property boundary. This provides the basis for the convention in all air pollution measurement and reporting that NO_x emissions are expressed using the molecular weight of 46. In addition, 30 TAC §101.14 states "{w}here not otherwise specified in the rules, regulations, determinations, and orders of the {commission}, the procedures used for sampling air and measuring air contaminants, and the methods of expressing the findings shall be those commonly accepted and used in the field of air pollution control."

Specific language was added to the 2000 emissions inventory guidance reminding companies with CEMs to check the molecular weight of NO_2 used in their software programs. A handful of companies, including TXI in Ellis County, had been using the incorrect molecular weight for NO_2 when reporting data from their continuous monitors.

As discussed later in this preamble, because of the concerns raised by TXI regarding the company's error in reporting its NO_x emissions, the commission has revised the LWA ESAD from 0.76 lb NO_x/ton of product to 1.25 lb NO_x/ton of product. The revised ESAD continues to represent a 30% reduction in actual emissions, despite the numerical change, because the original LWA ESAD of 0.76 lb NO_x/ton of product was based on TXI's erroneous reporting of NO_x as NO rather than NO_2.

TXI stated that two proven NO_x reduction technologies for LWA kilns (coal and tangential firing, as opposed to the frequently used center-firing configuration with natural gas) already were being used on two of its three LWA kilns in 1997, and that the third kiln was subsequently converted to these technologies. TXI stated that based on stack test data, its LWA plant's NO_x emission rate is approximately 10% lower than the rate for LWA kilns included in AP-42. TXI asserted that the use of a 1997 baseline prevents TXI from taking advantage of the NO_x reductions it may have already achieved at its LWA plant by 1997.

It should be noted that under EPA's emission factor quality rating system, EPA assigned the AP-42 factor of 1.9 lb NO_x/ton of feed a "D" quality rating, which EPA defines as follows: "D--Below average: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of the emission factor are noted in the emission factor table." Consequently, a comparison of TXI's stack test data to AP-42 is not relevant. In addition, it should be noted that according to TXI's two stack tests on its LWA plant, TXI's NO_x emission rate, on the basis of lb NO_x/ton of product, actually *increased* from 1992 to 2000.

In addition, TXI did not specify whether its two LWA kilns which it stated were using coal and tangential firing in 1997 had, in fact, ever been equipped with a higher-emitting center-firing configuration with natural gas, and if so, when these two kilns were modified. As noted in the preamble to the December 2000 rule adoption (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)), the commission staff used the 1997 emissions inventory as the basis for considering various combinations of ESADs for various categories of equipment to achieve approximately a 90% reduction in point source NO_x emissions. Use of the 1997 emissions inventory is consistent with the method of analysis for all other equipment categories. In addition, use of the 1997 emissions inventory is consistent with the photochemical modeling analyses of NO_x point source emissions in support of the HGA ozone attainment demonstration, which are based on 1997 emissions. Therefore, use of the 1997 baseline was not arbitrary or unfair, as TXI has implied, but, in fact, was a necessary and consistent component of an approvable SIP revision.

TXI commented that Chapter 117 does not include an ESAD for hot mix asphalt plants. TXI asserted that there are 14 hot mix asphalt plants located in the middle of HGA (as opposed to the location of TXI's LWA kilns on the very western periphery of the HGA), with cumulative NO_x emissions of approximately 1.5 times that of TXI's three LWA kilns. TXI stated that all of the LWA kilns in HGA are at its Clodine LWA plant and asserted that it has been "unfairly targeted for regulation" because Chapter 117 includes an ESAD for LWA kilns but not for hot mix asphalt plants

The commission's point source NO_x control strategy is driven by the need for significant NO_x emission reductions, as documented by numerous modeling runs, and the availability of technically feasible controls to reduce point source NO_x emissions in order to maintain progress toward attaining the ozone NAAQS in HGA. The rules apply to major sources in HGA, as well as numerous minor sources, because modeling has shown that NO_x emissions from point sources in HGA are contributing to exceedances of the one-hour ozone NAAQS. The commission believes that it is appropriate for those sources which are contributing to the ozone problem to be part of the solution. The specific ownership of the thousands of units in HGA which are subject to the ESADs is not relevant and, therefore, was not considered in developing the commission's point source NO_x control strategy. Likewise, the fact that TXI owns all of the LWA kilns in HGA is irrelevant. Under TXI's logic, if a single entity owned all of the thousands of NO_x point sources in HGA, it would be unfair to that entity if it had to shoulder *any* of the emission reduction burden necessary to bring HGA into attainment with the ozone NAAQS because it would be "unfairly targeted for regulation."

Regarding hot mix asphalt plants, the commission disagrees with TXI's claim that it was "unfairly targeted for regulation." In 1997 TXI reported emissions of 153.02 tpy from its LWA plant, or 234.63 tpy if TXI had properly reported its NO_x emissions as NO_2 rather than NO. Taking at face value TXI's assertion that there are 14 hot mix asphalt plants in HGA which cumulatively emit 1.5 times as much NO_x as TXI's LWA plant would mean that the hot mix asphalt plants emit an average of approximately 25 tpy each. In contrast, TXI's LWA plant emitted 234.63 tpy in 1997, or over nine times as much as the average hot mix asphalt plant, based on TXI's own data. Even if each LWA kiln is compared to this average hot mix asphalt plant, each of TXI's LWA kilns emits over three times as much NO_x as the average hot mix asphalt plant.

The 1997 emission inventory which was used in the development of the ESADs did not list any sources under the Standard Industrial Classification (SIC) code for hot mix asphalt plants (SIC 2951). This is because hot mix asphalt plants are too small to inventory individually and because most of them are portable (i.e., temporarily located) plants which would not be inventoried as point sources, as confirmed by an extract from the current EI which revealed that of the 24 hot mix asphalt plants in HGA, the highest emissions reported NO_x emissions were only 6.6 tpy. Fifteen of the 24 hot mix asphalt plants are portable plants which move periodically to new construction projects not necessarily in HGA or even in Texas. Regardless, extension of the ESADs to include hot mix asphalt plants will be contemplated in the future if the emission reductions are needed to meet EPA and/or FCAA requirements. The commission does not believe that the possible need for such supplementary rulemaking in the future to regulate smaller sources such as hot mix asphalt plants is justification for exempting major sources which are subject to the current rule.

Ethyl opposed the proposed revisions and expressed support for the current NO_x requirements in HGA. Ethyl stated that many sources (including Ethyl) have already committed to reduce NO_x emissions according to the existing SIP.

The commission appreciates the support for the current NO_x requirements and appreciates the commenter's efforts to reduce NO_x emissions in HGA.

GHASP requested that the proposed revisions related to the implementation of the alternative ESADs proposed by BCCA-AG be clearly specified in the preamble so that the public and the commission may more easily make reference to the appropriate revisions without adversely affecting the other, unrelated revisions included in this proposal.

The rule proposal preamble clearly specified the revisions associated with the proposed implementation of BCCA-AG's alternate ESADs. GHASP's detailed comments on the proposed implementation of the alternate ESADs are an indication that these proposed changes were adequately described in the rule proposal preamble.

TXI resubmitted its September 25, 2000 comment letter concerning the Chapter 117 rulemaking and associated SIP revision which were adopted by the commission on December 6, 2000. TXI had initially submitted this comment letter during the comment period for the referenced previous rulemaking and associated SIP revision.

The comments in the TXI comment letter dated September 25, 2000 were addressed in the ANALYSIS OF TESTIMONY section of the preamble to the earlier Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register*. The commission's responses to the issues raised in the TXI comment letter dated September 25, 2000 are unchanged except as discussed later in this preamble under the ESAD - LIGHTWEIGHT AGGREGATE KILNS and COST headings.

AECT and TXU commented that the rule proposal preamble stated in the PUBLIC BENEFITS AND COSTS heading that the amendments will have the benefit of "potentially reduced costs associated with the reduction of public exposure to *NO_x* emitted from affected stationary sources, reduction of ground-level ozone in ozone non-attainment areas, and the conformance with the requirements of the FCAA." (AECT's and TXU's emphasis supplied.) AECT and TXU stated that there is no explanation of how the reduction of CO from coal-fired units in the East Texas attainment area will assist in reducing public exposure to NO_x and ground-level ozone. AECT and TXU asserted that in order to achieve compliance with the CO limit, coal-fired EGFs in east and central Texas will be forced to limit the amount of NO_x reductions otherwise attainable, which AECT stated would jeopardize compliance with the NAAQS in DFW, HGA, and the Tyler/Longview/Marshall area. AECT and TXU stated that the FCAA does not require or even suggest that the proposed CO limit be imposed and noted that the commission does not intend to include the CO limits in the SIP submittal to EPA.

The commission agrees that the portion of the rule proposal preamble cited by the commenters inadvertently focused on NO_x emissions and did not include all anticipated benefits of the rule proposal. However, the rule proposal preamble specified that the new CO limits are necessary to prevent large increases in ammonia and CO emissions concurrent with the installation of NO_x controls. Therefore, another benefit of the rule proposal is reduction of public exposure to CO and ammonia emitted from affected stationary sources. The commenters' issues regarding the actual CO limit and the interrelation with NO_x emissions are addressed later in this preamble under the CO AND AMMONIA EMISSIONS heading.

RIA DETERMINATION

AECT and TXU commented on the draft RIA and stated that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule as defined in Texas Government Code, §2001.0225. AECT and TXU stated that the commission claimed that because the proposed rules are being adopted for inclusion in the Texas SIP, they are specifically required by federal law and are therefore exempt from the RIA requirements. AECT and TXU stated that elsewhere in the rule proposal preamble, the commission stated that the proposed CO limit of §117.135(2)(A) and alternative case-specific specifications of §117.151 will *not* be included in the SIP in order to simplify the approval process for alternative limits. (AECT's and TXU's emphasis supplied.) AECT and TXU stated that the proposed CO limit is not required, or even suggested, by any federal or state law. AECT and TXU asserted that it is doubtful whether the proposed CO limit will produce any discernable benefits and will "most certainly mandate exorbitant expenditures." AECT and TXU stated that as such, the proposed CO limit by itself constitutes a major environmental rule that exceeds any standard set by federal law. AECT and TXU asserted that given the "very significant capital costs" to achieve the proposed 400 ppmv CO limit, the commission is required to prepare an RIA for the proposed CO limit.

As discussed elsewhere in this preamble, the objective of the commission's proposal to limit CO was to ensure that the NO_x controls did not unnecessarily increase as well as to effectuate reductions of CO emissions, and other emissions of products of incomplete combustion from the affected power plants. CO is an identified harmful air pollutant. The EPA regulates CO as one of the six "criteria" pollutants for which an NAAQS has been established. CO is also known to play a limited role in ozone formation. As an organic compound, CO has a lower photochemical reactivity (i.e., ozone formation potential) than methane or ethane, but it is nonetheless an emission input in the photochemical modeling due to the large quantity of actual emissions, primarily from mobile sources. VOC emissions are also products of incomplete combustion, and may concurrently increase with CO increases. Any VOC increases associated with higher CO emissions are of concern to the commission because of their potential to exacerbate ozone formation. Other products of incomplete combustion which tend to increase with CO include reactive organic compounds, which contribute to ozone formation, and hazardous organic compounds, which have much lower impact thresholds of concern than CO. In the absence of specific studies, the commission considers it a worthwhile objective to achieve significant reductions, or avoidance of significant increases of CO, if it can be achieved at little additional effort by owners of emitting facilities.

Because information received revealed that CO emissions are so much higher than previously understood, it will be necessary to assess whether the CO increases include significant increases in reactive organic compounds, which could limit the effectiveness of the ozone control strategy. Gathering information on VOC emissions will also require additional time. Therefore, as discussed elsewhere in this preamble, the commission has revised §117.135(2) to delete the CO limit and the associated monitoring requirements.

The commission disagrees that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule as defined in Texas Government Code, §2001.0225. The commission acknowledges that the portion of the RIA which stated that the proposed rules are being adopted for inclusion in the Texas SIP because they are specifically required by federal law was not specific about the rules regarding CO emissions, and was focused on NO_x emissions. The CO rules were designed to be a portion of the state's air control plan, and the commission has the authority to regulate the quality of the state's air, specifically having authority to establish ambient air quality limits to effectuate the purpose of the TCAA, as well as implement measures to ensure compliance with NAAQS.

The commission has the responsibility to prepare a final RIA after considering public comment on the draft RIA. However, because the commission is not adopting the CO limit and associated monitoring rules, no final RIA regarding CO emissions is required. Because the commission has not conducted a full RIA, it is not appropriate nor relevant to speculate on what the conclusions of that would be.

The commenters' issues regarding the actual CO limit and the interrelation with NO_x emissions, as well as specific comments regarding costs, are addressed later in this preamble under the CO AND AMMONIA EMISSIONS and COST headings, respectively.

Louisiana-Pacific commented on the draft RIA and stated that had the commission conducted a full RIA, it could only conclude that the reductions proposed in §117.206(c)(5) for wood-fired boilers are "not technically or economically achievable at the present time" and that the commission should consider "a different, and achievable, emission specification."

Because the commission has not conducted a full RIA, it is not appropriate nor relevant to speculate on what the conclusions of that would be. As discussed elsewhere in this preamble, the commission has previously determined that both the original and revised ESADs are technically feasible.

DEFINITIONS
GHASP supported the proposed changes to the definitions in §117.10.

The commission appreciates the support.

NASA stated that the definition of emergency situation in the renumbered §117.10(15)(A) should be revised to allow operation of stationary diesel generators for scheduled outages such as planned maintenance outage requests by the electric utility (Reliant) affecting incoming feeders, or internal NASA outages to test, repair, troubleshoot, and maintain facilities (including high voltage systems, substations, or air switches) or tie in new circuits. NASA stated that the operation of a stationary emergency diesel generator for a single scheduled outage can require 48 hours or more. NASA stated that if operation of stationary emergency generators is prohibited for scheduled outages, it will be "forced to use exempt portable backup generators" instead to carry critical loads, which would violate National Fire Protection Association (NFPA) Standard 110 and would result in higher costs (and possibly higher NO_x emissions) compared to using existing stationary generators. NASA noted that it has the alternative of adding its existing diesel generators (a total of 24 units) into the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, but stated that this would result in significantly increased costs to perform quarterly testing for NO_x and CO on each engine per §117.214(b)(2) and additional effort to track allowances for 30 units instead of only NASA's six boilers.

The existing definition of emergency situation was, as the term implies, developed to define emergency situations. It was not intended to include scheduled outages, which, as NASA noted, can be lengthy. NASA would not be "forced to use exempt portable backup generators" under the definition of emergency situation. It appears that NASA's usage of its stationary diesel generators is simply far greater than envisioned under the exemptions in §117.203(a)(6)(D) and (11). Should NASA's existing engines not qualify for exemption under §117.203(a)(6)(D) and (11), they would be subject to the ESADs under §117.206(c)(9)(D) in conjunction with the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3. The commission evaluated the effort required to track allowances for the mass emissions cap and trade program in the rulemaking for those Chapter 101 rules and concluded that the effort required was reasonable. In addition, it should be noted that §117.214(b)(2) specifies that quarterly testing is not required for those engines whose monthly run time does not exceed ten hours. While the commission has not made any changes to the definition of emergency situation in response to NASA's comments, it has updated the references to the ERCOT Protocols in this definition.

Phillips stated that the definition of incinerator in the renumbered §117.10(21) should be revised to exclude vapor combustors, thermal oxidizers, and other VOC control devices. TxOGA made a similar comment, and Phillips and TxOGA stated that the ESAD in §117.206(c)(16) for these units is inappropriate. Phillips further stated that the ESADs for these units are economically infeasible, and that it knows of no existing NO_x controls installed on these types of devices.

The commission does not believe that the definitions section (i.e., §117.10) is the appropriate place to address concerns about §117.206(c)(16), and has made no changes to §117.10 in response to the comments. The commission instead is addressing the commenters' concerns later in this preamble under the ESAD - INCINERATORS heading. While the commission has not made any changes to the definition of incinerator in response to the comments, it has revised this term to clarify that the term incinerator does not apply to a unit which functions as a control device in addition to functioning as a boiler or process heater. This is necessary to ensure that boilers and process heaters remain subject to the appropriate boiler and process heater emission specifications in the event that these units are also function as VOC control devices. In addition, the commission has revised the definition of incinerator to clarify that this term does not apply to flares, as defined in §101.1.

For owners or operators who may be concerned about possible confusion between boilers and incinerators, the commission notes that the EPA definition of boiler in 40 CFR §260.10 states that a boiler is an enclosed device using controlled flame combustion and having the following characteristics: 1) the combustion chamber and primary energy recovery section must be of integral design; 2) thermal energy recovery efficiency must be at least 60%; and 3) at least 75% of the recovered energy must be "exported" (i.e., not used for internal uses such as preheating of combustion air or fuel, or driving combustion air fans or feed water pumps) and used. The commission suggests that owners or operators consider this definition if, after reviewing the revised definition of incinerator, they are still unclear as to whether or not a combustion unit is a boiler or an incinerator.

TECHNICAL FEASIBILITY OF EXISTING ESADS

BCCA-AG and Lyondell stated that the current ESADs are not technically feasible for many source categories. BCCA-AG and Lyondell asserted that comments submitted by BCCA and other commenters on the August 2000 proposed SIP, documents compiled by the commission and produced in discovery in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, and the testimony of Doug Deason (Deason) and Jess McAngus (McAngus) in the temporary injunction hearing held before Judge Margaret Cooper, Travis County District Court, Texas, on May 14 - 18, 2001, establish that the alternative ESADs are the maximum technically feasible retrofit NO_x controls for point sources.

In claiming that the alternative ESADs are the maximum technically feasible retrofit NO_x controls for point sources, BCCA-AG and Lyondell are, in effect, claiming that the ESADs as adopted December 6, 2000 and as revised September 26, 2001 are not technically feasible. The commission disagrees with both of these BCCA-AG/Lyondell positions. In the December 2000 adoption of the original ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of those ESADs. The commission determined that the various controls

which can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. A detailed explanation of how the commission reached these conclusions is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524).

In the adoption of the September 26, 2001 revisions to Chapter 117, the commission refuted the testimony of Deason and McAngus in the temporary injunction hearing in which these BCCA-AG witnesses claimed that the original ESADs were not technically feasible. (It should be noted that the hearing held in May 2001 was not completed before a settlement in principle was reached.) The commission also refuted the testimony of other BCCA-AG witnesses in the temporary injunction hearing, and again concluded that the ESADs are technically feasible. A detailed explanation of how the commission refuted the testimony of BCCA-AG witnesses and again concluded that the ESADs are technically feasible is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8110).

With regard to technical feasibility, EPA noted that the proposed limit for gas-fired utility boilers of 0.030 lb/MMBtu is roughly twice the limit in the South Coast Air Quality Management District (SCAQMD) rules of 0.015 lb/MMBtu. For rich-burn engines, EPA noted that the proposed limit is 0.5 g/hp-hr, well above the Ventura County Air Pollution Control District (VCAPCD) limit for these units. EPA also stated that is ample evidence provided in the December 2000 adoption that more stringent levels than the proposed Chapter 117 limits have been achieved in California at non-utility boilers, process heaters, gas turbines, and fluid catalytic cracking units (FCCUs).

The 1991 SCAQMD Rule 1135 has an output-based standard for gas-fired utility boilers of 0.15 lb NO_x/megawatt-hour (lb NO_x/MWh), which is approximately equal to a heat input standard of 0.015 lb/MMBtu. The commission agrees that the proposed alternate ESAD for gas-fired utility boilers of 0.030 lb/MMBtu is approximately double the limit in SCAQMD Rules 1135. Similarly, VCAPCD Rule 59 has an output-based standard for gas-fired utility boilers of 0.10 lb/MWh, essentially equal to 0.010 lb NO_x/MMBtu. The alternate ESAD for gas-fired utility boilers of 0.030 lb/MMBtu is approximately three times the limit in VCAPCD Rule 59. The commission also notes that numerous examples of units achieving NO_x emissions at or below the ESADs were described in the preambles to the Chapter 117 rulemakings which were published in the January 12, 2001 and October 12, 2001 issues of the *Texas Register*. More recent examples are included later in this preamble.

IMPLEMENTATION OF ALTERNATE ESADS
BCCA-AG, Chevron, Dow, Lyondell, Phillips, Reliant, and TxOGA supported the proposed substitution of the alternate ESADs in §117.106(c)(5) in lieu of the corresponding ESADs in §117.106(c)(1) - (3) and the substitution of the alternate ESADs in §117.206(c)(18) in lieu of the corresponding ESADs in §117.206(c)(1) - (17) in conjunction with controls on HRVOCs as part of the proposed Chapter 115 revisions. BCCA-AG and Lyondell stated that the proposed implementation of the alternate ESADs and controls on certain HRVOCs will increase the effectiveness of the HGA SIP control strategy. BCCA-AG and Lyondell stated that there is “ample scientific, legal and policy

support at this juncture for the adoption of the alternate ESADs" based on the current understanding of ozone formation in HGA and additional modeling analysis performed by the commission. BCCA-AG and Lyondell further asserted that the proposed implementation of the alternate ESADs is supported by "an overwhelming weight of evidence indicating that reductions of HRVOC emissions will reduce peak ozone levels by more than the last 10% of point source NO_x emission reductions called for in the December 2000 SIP."

Specifically, BCCA-AG and Lyondell stated that previous modeling sensitivity runs found in the May 1998 HGA SIP and ENVIRON's *Diagnostic Analysis of the COAST Domain Modeling of September 6-11, 1993 Including CAMx Process Analysis* (May 2000) had shown that reductions in VOC emissions would reduce ozone levels in HGA. BCCA-AG and Lyondell stated that ENVIRON used process analysis to derive an explanation for the "steep" NO_x control requirement predicted by the photochemical modeling. BCCA-AG and Lyondell stated that data from the TexAQS and findings from the Accelerated Science Evaluation show that biogenic VOC do not contribute significantly to peak ozone formation and that some anthropogenic VOC, primarily highly reactive VOCs, are more abundant and much more important to ozone formation than previously believed. BCCA-AG and Lyondell stated that these recent science findings show that peak ozone levels would be more sensitive to reactive VOC reductions than the earlier modeling portrayed. BCCA-AG asserted that by reducing the appropriate VOC emissions sufficiently, point source NO_x emission reductions beyond 80% become *superfluous* to attainment. (BCCA-AG's and Lyondell's emphasis supplied.)

The commission provided evidence in the proposed SIP revision that reductions in emissions of certain HRVOCs might be substituted for part of the originally required reductions in NO_x emissions without increasing peak ozone levels in the area. However, it would be premature to call this evidence "overwhelming." At the time the June proposal was developed, the modeling for the 2000 TexAQS episode showed only marginal performance, so some caution was necessary in applying the results of the modeling analysis. Since that time, the TexAQS modeling staff has improved the modeling representation of the TexAQS episode and has much greater confidence in its ability to accurately characterize ozone formation in HGA. Additional modeling analyses have been conducted prior to final adoption of this proposed SIP amendment. This modeling provides a more robust basis for determining the feasability of trading VOC reductions for NO_x reductions, and in fact indicates that it is feasible to substitute reductions in HRVOC emissions for the last 10% of NO_x reductions.

The TexAQS results have dramatically improved the understanding of how ozone forms in the HGA area, and the June, 2002 modeling results were the first opportunity to incorporate these results into the modeling, thence into the regulatory process. Results of the Phase I MCR modeling indicate that the model now responds well to HRVOC emission reductions, and that significant progress towards attainment can be made using HRVOC emission reductions. However, in some cases, the model also responds to reductions of NO_x, so it not appropriate to term the last 10% of NO_x reductions "superfluous." Further analysis which is being conducted for Phase 2 of the MCR will help determine whether additional NO_x reductions, together with VOC reductions, will be necessary to reach attainment.

GHASP and Sierra-Houston opposed the proposed substitution of the alternate ESADs in lieu of the current ESADs. GHASP supported the proposed deletion of the alternate ESADs in §117.206(c)(18). EPA and GHASP stated that there is no documentation that the ESADs were proposed for revision because of technical infeasibility and noted that the rule proposal preamble cites the December 2000 adoption of the original ESADs, where the commission determined that the various controls that can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. GHASP noted that proposals similar to the alternate ESADs were rejected by the commission in December 2000 and stated that the alternate ESADs are arbitrary because the commission's only justification for their proposal is that they were submitted to a court by an organization (BCCA-AG) that has filed a lawsuit against the commission. EPA stated that when the commission entered into the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, it was EPA's understanding that, if Texas decided to relax the existing ESADs, an alternative attainment demonstration would be developed demonstrating attainment could be reached without the existing ESADs. EPA and GHASP stated that to date this alternative attainment demonstration has not been provided. EPA and GHASP further stated that there continues to be a shortfall in NO_x emission reductions and expressed concern that technically feasible controls are being relaxed when there is a shortfall in needed emission reductions.

The commission agrees that the basis for proposing alternate ESADs was not that the ESADs are technically infeasible. As noted by the commenters, in the December 2000 adoption of the original ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of those ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. However, as stated earlier in this preamble, Texas is legally entitled to determine what sources to control and how to control them, and that the state has the responsibility, and the discretion, to make such determinations. The commission noted that the alternate ESADs were provided to the commission by BCCA-AG, but disagrees that the basis for adopting these is arbitrary. Rather, the commission solicited comment regarding the alternate ESADs and whether those reductions represent a level of NO_x reductions that, in conjunction with the revisions to Chapter 115 being adopted concurrently (described elsewhere in this issue of the *Texas Register*), are equally effective in reducing ozone in HGA as the current ESADs.

As discussed in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES part of this preamble, commission staff has focused on substituting industrial VOC controls for the last 10% of reductions required by industrial NO_x emission limit rules and determining which VOCs should be controlled if industrial VOC controls are found to be effective. Results of photochemical grid modeling and analysis of ambient VOC data indicate that it is possible to achieve the same level of air quality benefits with reductions in industrial VOC emissions, combined with an overall 80% reduction in NO_x emissions from industrial sources, as would be realized with a 90% reduction in industrial NO_x emissions. This conclusion is based on results from several studies, including photochemical grid modeling of the August - September 2000 episode using a top-down emissions inventory adjustment to point source HRVOC emissions, and analyses of ambient HRVOC measurements made by commission automated gas

chromatographs and airborne canisters using the MIR and OH reactivity scales. Four HRVOCs clearly play important roles in HGA's ozone formation, and these four (ethylene, propylene, 1,3-butadiene, and butenes) seem to be the best candidates for the first round of HRVOC controls. Analysis to date shows that limiting emissions of ethylene, propylene, 1,3-butadiene, and butenes in conjunction with an 80% reduction in NO_x is equivalent in terms of air quality benefit to that resulting from a 90% point source NO_x reduction requirement.

BCCA-AG and Lyondell stated that the commission should adopt the alternate ESADs because, in combination with targeted controls on HRVOCs, such a control strategy is more likely to attain the ozone standard than the current strategy. BCCA-AG and Lyondell asserted that the current SIP will not attain the standard because of the model's failure to address rapidly-forming and spatially-limited ozone plumes (ozone "spikes") driven by HRVOC emissions and insufficient controls on HRVOCs. BCCA-AG and Lyondell commented that the proposed SIP revision substitutes a suite of HRVOC controls for the last 10% of point source NO_x emissions, which they asserted are unnecessary for attainment. BCCA-AG and Lyondell further asserted that because the revised SIP will increase the likelihood that the SIP control strategy will attain the standard, it should be adopted on that basis alone.

The commission agrees that controls on HRVOC emissions will be necessary for the HGA area to reach attainment. The current SIP revision includes reductions in HRVOC emissions which will reduce ozone as much or more than the last 10% of NO_x reductions. The commission appreciates the willingness expressed by Lyondell and BCCA-AG to make the considerable reductions to HRVOC emissions that will be necessary to reach attainment.

BCCA-AG and Lyondell stated that the estimated point source NO_x reductions of 535 tpd from the alternate ESADs, while admittedly less than the estimated 588 tpd reductions from the existing ESADs, represent an unprecedented magnitude of NO_x reductions, especially in such a short period of time. BCCA-AG and Lyondell stated that no agency has imposed a greater overall point source NO_x reduction mandate in any area in the world. BCCA-AG and Lyondell further asserted that not only do point sources continue to bear the brunt of the SIP NO_x control strategy if the alternate ESADs are adopted, but their overall burden in achieving attainment is in no way lessened because the proposed HRVOC controls apply exclusively to point sources. BCCA-AG and Lyondell stated that although they believe that the combination of the alternate ESADs and HRVOC rules will be more feasible than the current ESADs alone, the point sources nonetheless will shoulder the same measure of responsibility for bringing the HGA into attainment by 2007.

Because of Houston's unique circumstances, it is unlikely that another nonattainment area will require as large a NO_x point source reduction. The reductions required to meet the standard depend on the number and degree of exceedances. Currently, only Los Angeles has ozone exceedances in number and degree similar to Houston's. The intensity of summertime sunlight is also a factor, which puts cities in southern latitudes like Los Angeles and Houston at a disadvantage in comparison to more northern cities. Singularly, Houston has the highest percentage of point source NO_x emissions of total NO_x emissions of the nine severe and one extreme ozone nonattainment areas in the United States. Therefore, it is entirely appropriate that point sources have the greatest emission reduction requirements because those sources contribute the most to causing HGA's ozone nonattainment status.

There are other large urban areas with a severe ozone designation and a petroleum refining presence, such as Philadelphia. Philadelphia, however, is primarily basing its current attainment projections on reductions in regionally transported ozone. Likewise, Milwaukee and Chicago are focusing on reductions in regionally transported ozone. Some of the other severe ozone nonattainment areas have not completed development of their emission specifications for the one-hour attainment demonstrations required by the 1990 FCAA.

In addition, areas in the country other than Houston have large concentrations of refining and petrochemical plants. Most of these areas have smaller populations and less total on-road and non-road emissions, and therefore either already attain the one-hour ozone standard or are predicted to attain the standard with far more modest reductions than required in Houston. Such areas include Corpus Christi and BPA, Texas and Lake Charles, Louisiana.

BCCA-AG and Lyondell stated that Texas is legally entitled to determine what sources to control and how to control them. BCCA-AG and Lyondell stated that there is no limitation on the commission submitting a proposed revision to its SIP control strategy to EPA at any time and that EPA's role is limited solely to determining whether the submission meets the requirements of the 1990 Amendments to the FCAA. BCCA-AG and Lyondell stated that as long as the commission demonstrates that the ozone standard will be attained, it is entirely within the commission's discretion to determine what sources will be controlled and in what way. BCCA-AG and Lyondell stated that the United States Supreme Court recently reaffirmed that "it is to the States that the {FCAA} assigns initial and primary responsibility for deciding what emissions reductions will be required and from what sources." *Whitman v. American Trucking Associations, Inc. et al.*, 121 S.Ct. 903, 911 (2001).

The commission agrees that Texas is legally entitled to determine what sources to control and how to control them, and that the state has the responsibility to make such determinations. However, in making these determinations, the commission is subject to applicable federal and state law which limits the types of sources that the state can control. The commission disagrees that EPA's role is limited solely to determining whether the submission meets the requirements of the 1990 amendments to the FCAA. For example, 42 USC, §7511a, also contains specific requirements that states must include in plan revisions, such as RACT and an inspection and maintenance program. Further, EPA has also promulgated rules regarding requirements that states must follow for SIP submittals.

BCCA-AG and Lyondell commented that the existing §117.106(c)(5) and §117.206(c)(18) state that "in the event that the total NO_x emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 baseline emissions inventory baseline, the revised specifications *shall be* the lower of" certain permit limits or the specific alternate ESADs in §117.106(c)(5) and §117.206(c)(18). (BCCA-AG's and Lyondell's emphasis supplied.) BCCA-AG and Lyondell asserted that as a result, if the commission makes a determination that 80% point source NO_x reductions are required for attainment, the allocation of the relief afforded by any such determination has already been made. BCCA-AG and Lyondell asserted that the only means for NO_x relief for other source categories is if the commission determines that less than 80% NO_x reductions are required for attainment. BCCA-AG and Lyondell stated that in 2001, the commission solicited and considered public comment on the specific source category limits represented by the alternate ESADs and that no comments suggested that the alternate ESADs should be allocated among point sources in a manner different from BCCA-AG's alternate ESADs in the event that the commission determines that less than 80% NO_x reductions are required for attainment. BCCA-AG and Lyondell asserted that because public comment was taken in 2001 on the allocation represented by the alternate ESADs, no further consideration of the subject is appropriate.

BCCA and Lyondell correctly quote the rule language, but ignore the qualifying language that was included in §117.106(c)(5) and §117.206(c)(18). That language states that, if and to the extent supported by the commission's continuing scientific assessment of the causes of and possible solutions to the HGA nonattainment status for ozone, the executive director determines that attainment can be reached with fewer NO_x emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop proposed rulemaking regarding the ESADs. In the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, the commission agreed that the commission may adopt a rule that: 1) confirms the determination that the 80% option (emission specifications that establish an approximate area-wide blended 80% point source NO_x reduction, which would result in a total reduction of not less than 535 tpd NO_x emissions from utility and non-utility point sources in the HGA area) is appropriate; 2) retains the 90% option (the ESADs adopted by the commission in December 2000, which establish an approximate area-wide blended 90% point source NO_x reduction); or 3) establishes revised ESADs that are different than either the 80% option. The adoption of rules which establish the potential alternate ESADs in 2001 does not preclude the commission taking comment on these proposed revised ESADs again. Rather, the commission is required by the Texas Administrative Procedure Act (APA), Texas Government Code, Chapter 2001, to provide all interested persons a reasonable opportunity to submit data, views, or arguments on the proposed rules. The Consent Order specifically states that the commission reserves any legal rights it has (absent the Consent Order) under the APA, TCAA, Texas Water Code (TWC), FCAA, or other applicable law. The commission made it clear in its 2001 rulemaking that the scientific assessment was ongoing and that the executive director would develop proposed rulemaking to address the alternate ESADs, which is the subject of this action by the commission.

BCCA-AG and Lyondell stated than even if the commission reassesses the level of NO_x reductions required for the various point source categories under the 80% option, the alternate ESADs as they currently appear in §117.106(c)(5) and §117.106(c)(1) - (3) should be adopted. BCCA-AG and Lyondell noted that as part of the development of the December 2000 SIP and subsequent refinements to it, the commission has accumulated a wealth of data and received considerable public input on the technical feasibility and cost of various levels of NO_x control for each source category, including numerous formal comments submitted in response to the commission's originally proposed ESADs in August 2000, as well as the testimony of Deason and McAngus at the temporary injunction hearing in May 2001. BCCA-AG and Lyondell asserted that this body of data and analysis more than adequately supports the adoption of the alternate ESADs without change.

As noted earlier in this preamble, in the December 2000 adoption of the original ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of

those ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. A detailed explanation of how the commission reached these conclusions is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524).

In the adoption of the September 26, 2001 revisions to Chapter 117, the commission refuted the testimony of Deason and McAngus in the temporary injunction hearing in which these BCCA-AG witnesses claimed that the original ESADs were not technically feasible. (It should be noted that the hearing held in May 2001 was not completed before a settlement in principle was reached.) The commission also refuted the testimony of other BCCA-AG witnesses in the temporary injunction hearing, and again concluded that the ESADs are technically feasible. A detailed explanation of how the commission refuted the testimony of BCCA-AG witnesses and again concluded that the ESADs are technically feasible is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8110).

BCCA-AG and Lyondell acknowledged that refinement of the SIP is an on-going process and that further adjustments to the SIP may be made during the 2004 - 2006 time frame based on the continuing availability of new data, modeling results, and analysis which are likely to improve the understanding of ozone creation in the HGA. BCCA-AG and Lyondell commented that such information may or may not provide a better basis on which to further refine the point source component of the control strategy and expressed an interest in continuing to collaborate with the commission and other entities in this regard. However, BCCA-AG and Lyondell stated that point source owners and operators must now make critical control technology decisions because of shutdown schedules, lead-times to design and engineer highly-complex controls in space-limited plant sites, limitations on critical contractor resources, and capital investment limitations. BCCA-AG and Lyondell stated that the control decisions are heavily influenced, and in some cases solely determined by, whether the alternate ESADs are adopted. BCCA-AG and Lyondell stated that adoption of the alternate ESADs after December 2002 date simply will be too late in many cases, and urged the commission to adopt the alternate ESADs at this time. GHASP stated that if the commission abandons the NO_x reductions provided by the original ESADs, then it may be rendering those measures effectively infeasible for re-adoption during the mid-course correction and noted that in the December 2000 rule adoption, the commission determined that it is necessary to "allow the more difficult to control or more expensive emission reduction projects six years to achieve the emission reductions." GHASP further stated that if the commission were to abandon the original ESADs, then found it necessary to re-adopt them in 2004, it could be bound by its prior finding to set a compliance deadline of 2010, which is inconsistent with HGA's 2007 attainment deadline.

The commission is required by the APA to adopt and file the rule adoption within six months after the date the proposal is published in the Texas Register, or else the proposal will be automatically withdrawn. Therefore, it is not possible for the commission to adopt the current rule proposal after December 2002. The last sentence of the BCCA-AG/Lyondell comment indicates that should further analysis after December 2002 (e.g., MCR) demonstrate that additional NO_x reductions above and beyond the alternate ESADs are necessary for HGA to achieve the one-hour ozone

NAAQS by the 2007 FCAA deadline, BCCA-AG and Lyondell would likewise believe such adjustments to the point source component of the HGA SIP to be "too late," thereby ensuring continued noncompliance with the one-hour ozone NAAQS past the mandated 2007 deadline.

BCCA-AG and Lyondell commented that the existing ESADs will result in widespread use of SCR and SNCR technologies, and that ammonia emissions will increase "by an order of magnitude" in Harris County (where the majority of point sources in HGA are located) due to ammonia slip and may lead to a "significant increase {in} ambient particulate matter concentrations" in HGA. BCCA-AG and Lyondell stated that implementation of the alternate ESADs would result in far fewer ammonia emissions and therefore would result in better overall air quality. BCCA-AG and Lyondell further stated that formation of fine PM will also be of less concern if the alternate ESADs are implemented.

As explained in detail in the preambles to the Chapter 117 rulemakings which were published in the January 12, 2001 and October 12, 2001 issues of the *Texas Register,* BCCA-AG overestimated by at least a factor of two the expected ammonia emissions in HGA due to ammonia slip from SCR and SNCR used to comply with the December 2000 and existing ESADs. Ammonia slip emissions (and therefore subsequent particulate formation) in any case will be insignificant in comparison to other existing sources of ammonia in HGA, which are estimated to be 23,862 tpy (from area sources, on-road and non-road mobile sources, and biogenics). Existing emissions of ammonia from point sources are estimated to be 1,802 tpy. Assuming ammonia slip at five ppmv (i.e., approximately 15 tpd) as a worst-case estimate from ammonia slip would result in a relatively modest increase in ammonia emissions of 20%, which is far less than "an order of magnitude." Due to the availability of the emissions cap and trade program and due to the ability of some Tier I controls to achieve the required reductions without the need for Tier II controls, the actual number of SCRs in operation are expected to be fewer than some commenters have suggested in previous rulemaking. The adoption of the nominal 80% ESADs will allow even more units to achieve the required reductions with Tier I controls, thereby further reducing the number of SCRs. Therefore, the actual ammonia emissions associated with ammonia slip would be expected to be less than previously estimated.

GHASP noted that the commission has solicited comments on the equitableness of the ESADs that would remain unchanged if the BCCA-AG's proposed alternate more lenient ESADs are implemented. GHASP stated that an "equitableness" standard does not have any basis in law and that the commission is required to adopt all reasonably available control measures. GHASP stated that the various controls that can be used to meet the ESADs are technically feasible, and thus the existing ESADs should be maintained and should not be changed for other source categories.

The commission agrees that an "equitableness" standard is not the basis for determining what controls are necessary for the SIP. In the December 2000 adoption of the original ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of those ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. However, as stated elsewhere in this preamble, Texas is legally entitled to determine what sources to control and how to control them, and that the state has the

responsibility, and the discretion, to make such determinations. The alternate ESADs represent a level of NO_x reductions that, in conjunction with the revisions to Chapter 115 being adopted concurrently (described elsewhere in this issue of the *Texas Register*), are equally effective in reducing ozone in HGA as the current ESADs.

As discussed in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES part of this preamble, commission staff has focused on substituting industrial VOC controls for the last 10% of reductions required by industrial NO_x emission limit rules and determining which VOCs should be controlled if industrial VOC controls are found to be effective. Results of photochemical grid modeling and analysis of ambient VOC data indicate that it is possible to achieve the same level of air quality benefits with reductions in industrial VOC emissions, combined with an overall 80% reduction in NO_x emissions from industrial sources, as would be realized with a 90% reduction in industrial NO_x emissions. This conclusion is based on results from several studies, including photochemical grid modeling of the August - September 2000 episode using a top-down emissions inventory adjustment to point source HRVOC emissions, and analyses of ambient HRVOC measurements made by commission automated gas chromatographs and airborne canisters using the MIR and OH reactivity scales. Four HRVOCs clearly play important roles in HGA's ozone formation, and these four (ethylene, propylene, 1,3-butadiene, and butenes) seem to be the best candidates for the first round of HRVOC controls. Analysis to date shows that limiting emissions of ethylene, propylene, 1,3-butadiene, and butenes in conjunction with an 80% reduction in NO_x is equivalent in terms of air quality benefit to that resulting from a 90% point source NO_x reduction requirement.

Goodyear-Houston stated that the proposed implementation of the alternate ESADs provides relief to certain source categories but none to others. Goodyear-Houston stated that in order to make the rules more equitable, all sites which include equipment subject to the new HRVOC rules should qualify for an ESAD representing an 80% reduction in NO_x emissions.

Goodyear-Houston is correct in noting that implementation of the alternate ESADs provides relief to certain source categories but none to others. However, the alternate ESADs were never intended to apply an equal across-the-board relaxation of the ESADs. Rather, the alternate ESADs represent a level of NO_x reductions that, in conjunction with the revisions to Chapter 115 being adopted concurrently (described elsewhere in this issue of the *Texas Register*), are equally effective in reducing ozone in HGA as the current ESADs. The commission has the authority to develop the plan for control of the state's air and as such can exercise its discretion regarding control strategies.

GHASP stated that commission has not properly analyzed the proposed alternative ESADs to determine the amount of NO_x emissions that would be expected to occur.

In the TABLES AND GRAPHICS section of this issue of the *Texas Register*, the table titled "Potential NO_x Emission Reductions from Implementation of the Alternate ESADs by Point Source Category for Houston/Galveston Nonattainment Area Counties - Revised 12/13/02" indicates the relative proportion of emissions according to equipment category and estimated reductions resulting from the implementation of the alternate ESADs, as well as the effect of the

revisions to the utility boiler ESADs in §117.106(c)(1) and the diesel engine ESADs in §117.206(c)(9)(D) which were adopted in September 2001. In addition, another table in the TABLES AND GRAPHICS section of this issue of the *Texas Register*, titled "Subcategories - Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties - Revised 12/13/02," further breaks down the equipment categories and indicates the estimated NO_x emission reductions which would result in the event that the alternate ESADs are implemented. These tables clearly delineate the expected amount of NO_x emission reductions and remaining NO_x emissions.

BCCA-AG and Lyondell stated that the purpose of the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, is to allow point sources flexibility in meeting the ESADs. BCCA-AG and Lyondell stated that the current ESADs are so stringent that there will be few surplus allowances and therefore no flexibility afforded by the mass emissions cap and trade program. BCCA-AG and Lyondell asserted that the adoption of the alternate ESADs will give sites with regulated point sources a feasible control level with a small compliance margin, so that the mass emissions cap will function as intended.

The commission disagrees with the BCCA-AG/Lyondell assertion that the current ESADs will result in few surplus allowances and no flexibility under the mass emissions cap and trade program. As previously provided in the specific examples of units achieving the ESADs (see the January 12, 2001 and October 12, 2001 issues of the *Texas Register*), many of these units are operating below the ESADs. This demonstrates that it is possible to use over-compliance to create surplus point source emission reduction credits under the adopted Chapter 101 mass emissions cap and trade program. Under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs and will function as intended. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

BCCA-AG and Lyondell stated that the FCAA requires that an attainment demonstration be based on photochemical modeling, but also provides for the use of other analytical methods and affords EPA and the states considerable latitude in determining the appropriate scientific methodology for a particular attainment demonstration. BCCA-AG and Lyondell stated that as the scope and complexity of the ozone problem has been more fully appreciated, EPA's attainment demonstration guidance has evolved to recognize the limitations of "modeling" attainment and the value of qualitative analysis. BCCA-AG and Lyondell asserted that the revised SIP, if it incorporates the alternate ESADs and HRVOC controls, is a refinement of the control strategy specifically designed to address this unique situation, and is fully consistent with the FCAA and applicable EPA guidance.

BCCA-AG and Lyondell commented that the rule proposal preamble states that "while the commission has proposed changing some of the current NO_x ESADs, detailed modeling which will quantitatively assess the overall effect of any changed ESADs, in conjunction with the proposed revisions to 30 TAC Chapter 115 to address highly reactive VOCs, will be used in the development of the final ESADs." BCCA-AG and Lyondell supported the commission's efforts to precisely quantify the level of NO_x reductions needed for attainment through traditional photochemical modeling, but asserted that it is not necessary to do so. BCCA-AG and Lyondell stated that under 42 USC, §7511a(d) and (c)(2)(A), the FCAA only requires that the attainment demonstration "be based on photochemical grid modeling or any other analytical method determined by the Administrator, in the Administrator's discretion, to be as least as effective."

BCCA-AG and Lyondell stated that EPA's guidance on attainment demonstrations has increasingly recognized the role of non-modeling methods. BCCA-AG and Lyondell commented that EPA's initial 1991 guidance on attainment demonstrations (*Guideline for Regulatory Application of the Urban Airshed Model* (July 1991), §6.4) called for photochemical modeling to forecast that the state's chosen control strategy would attain the standard in each of the grid cells of the model on each of the days during the modeling episode. BCCA-AG and Lyondell stated that EPA later updated the attainment test in its 1996 guidance on attainment demonstrations (*Guideline on the Use of Modeled Results to Demonstrate Attainment of the Ozone NAAQS*, EPA-454/B-95-007 (June 1996)) to allow deviations from this strict test in certain circumstances. BCCA-AG and Lyondell stated that in later guidance (*Guidance on Improving Weight of Evidence Through Identification of Additional Emission Reductions, Not Modeled* (1999)), EPA endorsed a specific approach for crediting the effects of certain controls without modeling them.

BCCA-AG and Lyondell stated that the 1996 guidance introduced the concept of "weight of evidence" (WOE), which allows states to present additional analysis, including "observational models" and "incremental costs and benefits," to determine whether an area will reach attainment. BCCA-AG and Lyondell stated that the 1996 guidance provides that *any* additional corroborative evidence may be brought to bear in an attainment demonstration. (BCCA-AG's and Lyondell's emphasis supplied.) BCCA-AG and Lyondell stated that the 1996 guidance was driven by information that EPA gleaned from the states' initial efforts with photochemical modeling. First, model predictions are uncertain due to uncertain inputs, computational limitations, and the level of scientific knowledge. Second, the controls estimated by the models to be necessary to attain the standard "can be very high."

BCCA-AG and Lyondell stated that the proposed SIP revision is fully consistent with the evolution in EPA attainment demonstration policy because the attainment demonstration is based on photochemical grid modeling, but with a supplemental WOE analysis using data from TexAQS and the Accelerated Science Evaluation in conjunction with a recognition of the difference in incremental costs and benefits attributable to the 90% NO_x and 80% NO_x/HRVOC options to demonstrate that the last 10% of modeled NO_x reductions from point sources can be replaced with a targeted set of controls on HRVOCs. BCCA-AG and Lyondell asserted that this refinement retains the integrity of the SIP, but will increase the likelihood that the HGA will attain the standard in a timely manner.

BCCA-AG and Lyondell asserted that use of observational data in conjunction with an incremental cost/benefit comparison is allowed by EPA's 1996 guidance. BCCA-AG and Lyondell stated that EPA's 1996 guidance (page 36) specifies that "observational models take advantage of monitored data to draw conclusions about the relative importance of different types of VOC and/or NO_x emissions as factors contributing to observed ozone" and that their role is "to provide a means for corroborating whether a control strategy identified in a photochemical grid modeling analysis is addressing key contributors to observed high ozone."

BCCA-AG and Lyondell stated that according to EPA's 1996 guidance (pages 36 - 37), if the results of the observational model contradict those of the photochemical model, the observational model "may support a position that controlling certain emissions further in pursuit of the benchmark should be postponed" and that "if small incremental benefits are accompanied by large incremental costs, this supports not immediately pursuing this particular strategy to come closer to passing the benchmark {for demonstrating attainment}." BCCA-AG and Lyondell stated that EPA's 1996 guidance also specifies: "Rather, . . . if the model predictions appear to be relatively unresponsive to additional controls, resulting in large incremental costs, it may be appropriate to conclude that model results are close enough to the benchmark, given other corroborative evidence."

The commission is aware of EPA guidance regarding weight-of-evidence, agrees that this guidance supports employing weight-of-evidence in the final SIP adoption, and has incorporated several additional arguments into its analysis, including the use of additional ozone metrics, observation-based modeling, and analysis of ambient hydrocarbon data collected by aircraft and surface sites. The observation-based model corroborates the conclusion that it is feasible to trade VOC reductions for the last 10% of NO_x reductions. The observation-based model also responds to both VOC and NO_x reductions, and, like the photochemical model, indicates that very large emission reductions may be necessary to achieve attainment. Additional analyses of ambient VOC data indicate that a large portion of the area's ozone generation likely is due to HRVOC emissions, hence the area would benefit from reductions to these emissions. These ambient VOC analyses, however, do not address the issue of response to reductions of NO_x emissions. Thus far, none of the analyses conducted by or presented to commission staff have contradicted the results of the photochemical modeling, which helps lend credence to the conclusions based on the modeling.

ESAD - UTILITY BOILERS
GHASP expressed its continuing opposition to the revised ESADs for utility boilers in §117.106(c) which were adopted on September 26, 2001.

The previous and existing ESADs for both utility and non-utility boilers are technically feasible, as discussed in detail in the ANALYSIS OF TESTIMONY sections of the preambles to the Chapter 117 rulemakings which were published in the January 12, 2001 and October 12, 2001 issues of the *Texas Register*. The point source NO_x control strategy as adopted on December 6, 2000 had an associated NO_x emission reduction of 595 tpd. While the revisions to the point source NO_x rules as revised on September 26, 2001 are expected to reduce NO_x by 586 tpd, the effect of this increase is counterbalanced by reductions enacted by the Texas Legislature requiring the permitting of grandfathered facilities in east and central Texas. The legislature requires certain grandfathered sources in this region to reduce emissions of NO_x by approximately 50%. The commission believes that the September 26, 2001 rulemaking will provide air quality benefits similar to the December 6, 2000 SIP revision for several reasons. First, NO_x emissions in east and central Texas will be significantly lower overall under the September 26, 2001 SIP than under the December 6, 2000 SIP revision. Second, ozone production efficiency at the sources affected by the recent legislation is expected to be very high, based on recently published results from an ozone study conducted in the Nashville, Tennessee area by the Southern Oxidant Study. Results from the Texas 2000 Air Quality Study indicate that ozone production at Reliant's W. A. Parish power plant is three to five times lower than what is expected from the rural grandfathered sources. No data is currently available on ozone production efficiency at other Reliant units, but it is expected to be somewhat higher than that at the Parish facility. Third, the increased NO_x emissions will occur at peaking units, which generate most of their emissions in the afternoon, at least during the ozone season. Modeling has shown that afternoon emissions are less important in ozone formation than are morning emissions.

In any case, the ESADs as revised September 26, 2001 are cost-effective in terms of cost per ton of NO_x compared to the ESADs in the December 6, 2000 SIP revision, and result in a very large reduction in emissions. Detailed modeling will be required to quantitatively assess the overall effect of these two compensating changes to the emissions inventory. The commission will address this issue during the first phase of the mid-course review.

ESAD - ICI BOILERS

Houston Marine noted that §117.475(c)(1) for boilers and process heaters at minor sources does not include a separate ESAD for liquid fuel-fired units, but rather applies an ESAD of 0.036 lb/MMBtu heat input (or 30 ppmv) NO_x, at 3.0% O_2, dry basis for all fuel types. Houston Marine stated that it has contacted numerous burner companies to determine the lowest NO_x level that can be achieved while burning diesel, waste oils, or used oils in small boilers, and that all but one of these companies have indicated that 90 - 95 ppmv NO_x is the lowest level that can be achieved with combustion modifications. Houston Marine stated that one company from California indicated that a level of 55 ppmv NO_x could be achieved when burning low-sulfur diesel fuel with a modulating burner, steam atomization, and flue gas recirculation (FGR). Based on this information, Houston Marine requested that the commission revise §117.475 to establish an ESAD of 0.072 lb/MMBtu heat input (or alternatively, 60 ppmv NO_x) for liquid-fired boilers and process heaters.

The commission's intent is that the ESADs for minor sources generally be achievable using combustion modifications. The commission has evaluated Houston Marine's documentation and agrees that liquid-fired units should have a separate ESAD as suggested. Consequently, the

commission has added a new §117.475(c)(1)(B) which specifies an ESAD of 0.072 lb/MMBtu heat input (or alternatively, 60 ppmv at 3.0% O_2, dry basis) for liquid-fired boilers and process heaters. The commission also clarified that the ESAD of 0.036 lb/MMBtu heat input (or 30 ppmv at 3.0% O_2, dry basis) is applicable to gas-fired units.

ESAD - COKE-FIRED BOILERS
AES stated that the commission should re-evaluate the existing coke-fired boiler ESAD of 0.057 lb NO_x/MMBtu in §117.206(c)(4). AES requested that the commission revise the ESAD to 0.20 lb NO_x per MMBtu, representing a 65% reduction.

AES stated that compared to coal firing, SCR catalysts implemented on coke-fired units are deactivated quicker, and achievable catalyst lifetimes are significantly reduced, and that this distinction is due to the high sulfur content (4.0 - 6.0%) and high vanadium content (approximately 1,600 ppm) of coke, with the apparent production of vanadium sulfate compounds which blind the catalyst beds.

AES stated that compared to coal-fired units, SCR catalysts on coke-fired units oxidize sulfur dioxide (SO_2) to sulfur trioxide (SO_3) at a higher rate, while typical coal-firing experience is that SCR increases SO_2 oxidation by 0.02% - 1.0% while catalysts in coke-fired experience increase SO_2 by 1.0% - 3.0% or higher. AES stated that the increased SO_3 and sulfuric acid (H_2SO_4) is not significantly removed by the existing dry electrostatic precipitator (ESP) nor by the existing wet limestone scrubbing systems used at the plant; the increased SO_3 /H_2SO_4 emissions may also exceed the capability of the existing wet electrostatic precipitator (ESP) used at its plant. AES asserted that fine PM in the stack discharge will increase by a minimum of 10%, which will constitute a major increase in $PM_{2.5}$ when the $PM_{2.5}$ NAAQS is implemented. AES stated that current measured levels of $PM_{2.5}$ in HGA indicate pockets where the NAAQS may be exceeded.

AES stated that because of experienced and predicted corrosion in the air heater section (which will receive the discharge from the SCR unit), ammonia slip from the SCR unit will have to be maintained at a lower level than typical for other SCR applications. AES stated that its design engineers have specified that ammonia slip from the SCR will have to be maintained at less than two ppmv, dry, at 3.0% O_2 to minimize additional sulfate condensation (and resulting corrosion) in the air heater. AES expressed concern about whether this limit can be achieved and maintained over a long term.

AES stated that systems such as the SCONOX process are not technically viable on coke-fired units, and that systems such as liquid oxidation scrubbing are either not demonstrated on coke-fired units or are more expensive even than SCR.

The commission appreciates AES's concerns about sulfur emissions and ammonia slip. Although the use of SCR may be technically challenging for the reasons described by AES, SCR catalyst formulations are adjustable to reduce sensitivities to various catalyst poisons. SCR has been employed in boilers firing high sulfur fuel oil (up to 5.4% sulfur) and on cement kilns in commercial demonstrations in Sweden and Germany. The inorganic compounds and PM present in the exhaust streams of these applications degrade the performance more rapidly than cleaner fuels and exhaust streams, thereby shortening the life of the catalysts. Although catalyst replacement cost may be higher relative to a conventional SCR, SCR is still technically feasible.

The commission notes that SCR is but one control option. In addition to SCR, there is an oxidation technology for NO_x reduction which has been successfully applied to a variety of full-scale commercial operations. This technology, low-temperature oxidation, injects ozone as the oxidant to form dinitrogen pentoxide (N_2O_5), which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. More recent full-scale commercial installations include: a natural gas-fired boiler in California, achieving 85% - 90% NO_x removal; a nitric acid pickling process in Pennsylvania, achieving 90% - 95% NO_x removal; and a 25 MW coal-fired boiler in Ohio, achieving 85% - 90% NO_x removal. In addition, full-scale commercial installation on a lead furnace in California is scheduled to occur in 2002. Recent pilot project demonstrations in HGA include a wood-fired boiler in summer 2002, and an FCCU in fall 2002.

The AES coke-fired boiler, with its existing scrubbers, would logically be a good candidate for NO_x scrubber technology because of the potential avoidance of capital expenditure for a new scrubber as well as the operational experience in place with the scrubbers. The low-temperature oxidation technology is capable of the 90% reductions envisioned by the coke-fired boiler ESAD, as is SCR, as described earlier in the response to AES's comments. Therefore, the commission has retained the existing coke-fired boiler ESAD of 0.057 lb/MMBtu. AES's comments about cost are addressed later in this preamble under the COST heading.

ESAD - WOOD-FIRED BOILERS
Louisiana-Pacific stated that the commission should re-evaluate the proposed revision of the wood-fired boiler ESAD in §117.206(c)(5) from 0.046 lb NO_x/MMBtu to 0.060 lb NO_x/MMBtu. Instead, Louisiana-Pacific suggested an ESAD of 0.130 lb NO_x per MMBtu.

The commission agrees that wood-fired industrial boilers and mixed-fuel industrial boilers can add some difficulty to the control of NO_x. However, there is enough theoretical and practical experience with SNCR in mixed fuel systems and wood-fired boilers to demonstrate the technical feasibility of SNCR. The science of computer modeling, and the improvement of injection, control, and sensor systems have made this possible. SNCR normally operates with real time control of reagent feed versus load, and follows swings quite closely. Proper use of these inputs also minimizes the formation of ammonia-related problems in the combustion system, cold end, and stack emissions. The commission is aware of a mixed fuel industrial boiler (based on wood waste, biomass sludge, etc.) at Bowater Newsprint's pulp and paper mill in Calhoun, Tennessee that is achieving a 62% NO_x reduction with urea-based SNCR. There have been no particular problems reported with the operation of Bowater's SNCR system since it was installed. The commission is aware of at least 16 other commercial applications of urea-based SNCR on wood- or wood/biomass-fired systems on boilers ranging in size from 130 to 550 MMBtu/hr, representing NO_x reductions of 35% - 60% (average of 51%). In some cases, the data for these individual units represent the guaranteed reduction percentages or the permitted limits, both of which are set to provide a "cushion" such that the actual emission reductions are greater than the targeted emission reductions. In other words, lower efficiencies may simply reflect the regulatory limit rather than the capability of the technology in the particular application.

SNCR is not adversely affected by inorganics in the exhaust because there is no catalyst to degrade, and the NO_x reductions are favored in the high-temperature zone where SNCR is located. However, SNCR is typically capable of reductions in the 50% - 60% range, not high enough to achieve the existing ESAD, although one option would be to install SNCR and use credits, which are available to the owners of the wood-fired boilers, to satisfy the remainder of the reductions.

Although the use of SCR may be technically challenging due to "dirty" exhaust streams, SCR catalyst formulations are adjustable to reduce sensitivities to various catalyst poisons. SCR has been employed in boilers firing high sulfur fuel oil (up to 5.4% sulfur) and on cement kilns in commercial demonstrations in Sweden and Germany. The inorganic compounds and PM present in the exhaust streams of these applications degrade the performance more rapidly than cleaner fuels, thereby shortening the life of the catalysts. Although catalyst replacement cost may be higher relative to a conventional SCR, SCR is still technically feasible. SCR has been operating on a 57 MMBtu/hr wood-fired boiler at Sauder Woodworking in Ohio since 1994, meeting its NO_x reduction objectives during that time.

In addition to SCR, there is an oxidation technology for NO_x reduction which has been successfully applied to a variety of full-scale commercial operations. This technology, low-temperature oxidation, injects ozone as the oxidant to form N_2O_5, which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. More recent full-scale commercial installations include: a natural gas-fired boiler in California, achieving 85% - 90% NO_x removal; a nitric acid pickling process in Pennsylvania, achieving 90% - 95% NO_x removal; and a 25 MW coal-fired boiler in Ohio, achieving 85% - 90% NO_x removal. In addition, full-scale commercial installation on a lead furnace in California is scheduled to occur in 2002. Recent pilot project demonstrations in HGA include a wood-fired boiler in summer 2002, and an FCCU in fall 2002.

SCR removal efficiency of 80% would be a more representative design goal for dirty fuel streams. The oxidation technology appears capable of the 90% reductions envisioned by the ESAD proposed in August 2000. However, emerging technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to more established technologies, and these challenges can compromise performance goals. Therefore, the commission is implementing the alternate ESAD of 0.060 lb/MMBtu for wood-fired boilers as proposed. This represents a 60% NO_x reduction, which is achievable with SNCR, SCR, and low-temperature oxidation. This ESAD will result in 0.07 tpd fewer emission reductions than the current ESAD.

ESAD - STATIONARY DIESEL ENGINES
GHASP supported the proposed revisions to §117.206(c)(9) and §117.475(c)(4)(A) which clarify that the emission specification for diesel engines is the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data.

The commission appreciates the support and believes that this change is necessary to ensure that an inadvertent windfall is not created for existing diesel engines which emit less than 11.0 g/hp-hr. In addition, it has come to the commission's attention that ESADs for stationary diesel engines rated at less than 50 horsepower (hp) were inadvertently included for minor sources in the existing §117.475(c)(4)(B)(i) - (iii). Because §117.473(a)(2)(A) exempts engines rated at less than 50 hp, these ESADs are superfluous. Therefore, the commission has deleted the existing §117.475(c)(4)(B)(i) - (iii) and has renumbered the existing §117.475(c)(4)(B)(iv) - (ix) as §117.475(c)(4)(B)(i) - (vi).

ESAD - GAS TURBINES
GHASP commented that the proposed revisions to §117.206(c)(10) divide stationary gas turbines into four categories based on MW rating. GHASP stated that this categorization is not described in the SECTION-BY-SECTION DISCUSSION of the preamble and does not appear to have been explained in any previous rulemaking.

The proposed revisions to §117.206(c)(10) implement the stationary gas turbine alternate ESADs which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC. GHASP is correct that BCCA-AG's stationary gas turbine alternate ESADs divide stationary gas turbines into four categories based on MW rating.

GHASP objected to proposed revisions to §117.206(c)(10) and stated that the commission should provide a technical basis for any revised standards that is specific to the category of pollution source equipment. GHASP further stated that the information presented by the commission is inadequate to determine the impact of the proposed revisions to §117.206(c)(10) on NO_x emissions, and requested the opportunity to formally comment on the proposed categorization after the commission provides a technical rationale.

The current ESADs are all technically feasible, as described earlier in this preamble. Therefore, all of the less-stringent alternate ESADs are likewise technically feasible. In the TABLES AND GRAPHICS section of this issue of the *Texas Register*, the table titled "Potential NO_x Emission Reductions from Implementation of the Alternate ESADs by Point Source Category for Houston/Galveston Nonattainment Area Counties - Revised 12/13/02" indicates the relative proportion of emissions according to equipment category and estimated reductions resulting from the implementation of the alternate ESADs, as well as the effect of the revisions to the utility boiler ESADs in §117.106(c)(1) and the diesel engine ESADs in §117.206(c)(9)(D) which were adopted in September 2001. In addition, another table in the TABLES AND GRAPHICS section of this issue of the *Texas Register*, titled "Subcategories - Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties - Revised 12/13/02," further breaks down the equipment categories and indicates the estimated NO_x emission reductions which would result in the event that the alternate ESADs are implemented. These tables clearly delineate the expected amount of NO_x emission reductions and remaining NO_x emissions.

ESAD - BIF UNITS
TCC stated that the BIF unit ESADs in §117.206(c)(3) may not be technically feasible for BIF units that burn wastes containing fuel-bound nitrogen. TCC stated that the burners are designed for high excess O_2, and the fuel-bound nitrogen in the waste stream is converted to NO_x. TCC requested that the rules provide a case-by-case exemption for BIF units that burn wastes containing fuel-bound nitrogen

Today's understanding of NO_x formation includes three different mechanisms for generation of NO_x. Thermal NO_x is formed by the oxidation of atmospheric nitrogen present in the combustion air. Prompt NO_x is produced by high speed reactions at the flame front. Fuel NO_x is formed by the oxidation of nitrogen contained in the fuel. Prompt NO_x is more likely to form in a fuel-rich environment because of its dependence on hydrocarbon fragments. This is very different than thermal NO_x, which is highly dependent upon air concentrations.

Chemically-bound nitrogen, also called fuel-bound nitrogen, is one of the three common production routes for NO_x emissions. NO_x emissions from fuel-bound nitrogen and high excess O_2 were presumably reflected in the emission factors that the BIF and incinerator owners provided to the commission in the emission rate survey conducted in the first quarter of 2000. The existing ESADs for BIF units in §117.206(c)(3) were developed from this information and therefore reflect the effects of fuel-bound nitrogen and high excess O_2. NO_x produced by fuel-bound nitrogen is not any different from NO_x formed by the other formation mechanisms, "thermal" or "prompt" NO_x. Because of this, the presence of fuel-bound nitrogen does not pose questions of technical feasibility that have not already been considered.

TCC also commented that Resource Conservation and Recovery Act (RCRA) requirements apply to BIF units, in addition to the in-development BIF maximum achievable control technology (MACT) standards for which additional control technologies are expected to be installed at about the same time as controls for the HGA SIP. TCC expressed concern that the technologies may not work as efficiently as advertised when installed in a sequential manner. Specifically, TCC stated that many wastes burned in BIF units contain components that cause catalyst fouling and poisoning, resulting in poor performance and higher operating costs, and may counter other technologies driving organic and/or dioxin destruction and metal removal. TCC suggested that the ESAD be relaxed to a level representing non-SCR technology.

Because the BIF MACT is not even scheduled to be proposed until December 2003, the final BIF MACT requirements would be mere speculation at this time. Obviously, it would be advantageous to design for both ESAD and BIF MACT standards simultaneously. Regardless, the existing BIF unit ESAD is not based upon combustion modifications due to the potential for affecting the hydrocarbon destruction and removal efficiencies, but instead is based upon flue gas cleanup (specifically, SCR). Consequently there is no impact on hydrocarbon destruction and removal efficiencies. Because the largest BIFs, those rated above 100 MMBtu/hr heat input, are industrial boilers burning liquid hydrocarbon wastes without high levels of inorganic "dirty" materials and without wet scrubbers, the use of SCR would not be a problem for the largest BIF boilers because hydrocarbon wastes combusted in these boilers produce exhaust products essentially indistinguishable from any hydrocarbon fuel. Therefore, the existing ESAD in

§117.206(c)(3)(A) for BIFs rated 100 MMBtu/hr heat input or greater is based on SCR at 90% control because these boilers combust hydrocarbon wastes which do not threaten to reduce the effectiveness of SCR as the flue gas cleanup application.

For smaller BIFs, the existing ESAD in §117.206(c)(3)(B) is based on 80% control, rather than 90%, to take into account the concerns raised that certain of the units have "dirty" exhaust streams, primarily with sulfur and chlorides, and a few with some metals and other inorganics. Liquid firing is almost a prerequisite for classification as a BIF, because gaseous materials are not regulated as hazardous waste under RCRA regulations. The units with "dirty" exhaust streams use wet scrubbers to remove acid gases and some of the other inorganics. Considering the "dirty" streams, SCR has been employed in a few high sulfur fuel oil applications, but the inorganic compounds present in the exhaust degrade the performance more rapidly than cleaner fuels.

In addition to SCR, there is an oxidation technology for NO_x reduction which has been successfully applied to a variety of full-scale commercial operations. This technology, low-temperature oxidation, injects ozone as the oxidant to form N_2O_5, which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. More recent full-scale commercial installations include: a natural gas-fired boiler in California, achieving 85% - 90% NO_x removal; a nitric acid pickling process in Pennsylvania, achieving 90% - 95% NO_x removal; and a 25 MW coal-fired boiler in Ohio, achieving 85% - 90% NO_x removal. In addition, full-scale commercial installation on a lead furnace in California is scheduled to occur in 2002. Recent pilot project demonstrations in HGA include a wood-fired boiler in summer 2002, and an FCCU in fall 2002.

The commission believes that the exhaust streams from the BIFs with higher levels of inorganics will pose greater technical challenges than the more common, cleaner streams. SCR removal efficiency of 80% would be a more reasonable design goal for "dirty" fuel streams. The BIF units with existing scrubbers would logically be good candidates for NO_x scrubber technology because of the potential avoidance of capital expenditure for a new scrubber as well as the operational experience in place with the scrubbers. The low-temperature oxidation technology is capable of the 90% reductions envisioned by the BIF ESAD. However, emerging developing technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to more established technologies and these challenges can compromise performance goals. Because of the concerns raised by the commenters about inorganic materials in the exhaust streams, the existing ESAD for the BIFs rated less than 100 MMBtu/hr heat input is either an 80% reduction from baseline, or 0.030 lb/MMBtu.

ESAD - INCINERATORS

BASF, DuPont, and TCC stated that the commission should re-evaluate the basis for the incinerator ESAD in §117.206(c)(16)(B) and consider raising it from 0.03 lb NO_x/MMBtu to 0.15 lb NO_x/MMBtu. BASF, DuPont, and TCC concluded that an ESAD of 0.03 lb NO_x/MMBtu is technically difficult to achieve. BASF, DuPont, Phillips, and TxOGA asserted that there is currently no known proven control technology for any incinerator to meet the specified ESAD of 0.03 lb NO_x/MMBtu. BASF and DuPont stated that their suggested ESAD of 0.15 lb NO_x/MMBtu would provide more flexibility for various incinerator types to meet the compliance requirements. TCC stated that SCR would be required to achieve 0.03 lb NO_x/MMBtu, but SNCR could be used to achieve 0.15 lb NO_x/MMBtu. TCC stated that waste fuels often contain catalyst poisons. BASF, DuPont, and TCC stated that the lack of revision to the incinerator ESAD while relaxing the ESADs of other equipment places an unfair burden on facilities using highly efficient waste incinerators. DuPont stated that hazardous waste incinerators are already heavily regulated by RCRA and MACT requirements. BASF and DuPont stated that in order to be 99.99% efficient (or higher) in destroying complex waste streams as required by RCRA permits, incinerators must operate at high temperatures which result in the natural generation of thermal NO_x, with additional NO_x generated from fuel-bound nitrogen. DuPont also stated that incinerators using liquid fuel (i.e. distillate oil) inherently have higher emission factors than those using gaseous fuel (i.e. natural gas).

The commenters' suggested ESAD of 0.15 lb NO_x/MMBtu represents the baseline and therefore would result in absolutely no emission reductions from incinerators. The commission considered the waste streams in the HGA incinerators in response to the comments and agrees with the commenters that certain of the units have "dirty" exhaust streams, primarily with sulfur and chlorides, and a few with some metals and other inorganics. The units with "dirty" exhaust streams use wet scrubbers to remove acid gases and some of the other inorganics. Considering the "dirty" streams, SCR has been employed in a few high sulfur fuel oil applications, but the inorganic compounds present in the exhaust degrade the performance more rapidly than cleaner fuels. SNCR will not be adversely affected by these inorganics, because there is no catalyst to degrade and the NO_x reductions are favored in the high-temperature zone where SNCR is located. However, SNCR is typically capable of reductions in the 50% - 60% range, not high enough to achieve the ESAD.

In addition to SCR, there is an oxidation technology for NO_x reduction which has been successfully applied to a variety of full-scale commercial operations. This technology, low-temperature oxidation, injects ozone as the oxidant to form N_2O_5, which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. More recent full-scale commercial installations include: a natural gas-fired boiler in California, achieving 85% - 90% NO_x removal; a nitric acid pickling process in Pennsylvania, achieving 90% - 95% NO_x removal; and a 25 MW coal-fired boiler in Ohio, achieving 85% - 90% NO_x removal. In addition, full-scale commercial installation on a lead furnace in California is scheduled to occur in 2002. Recent pilot project demonstrations in HGA include a wood-fired boiler in summer 2002, and an FCCU in fall 2002.

The commission believes that the exhaust streams from the incinerators with higher levels of inorganics will pose greater technical challenges than cleaner, hydrocarbon-only streams. SCR removal efficiency of 80% is a more reasonable design goal for dirty fuel streams. The incinerators with existing scrubbers would logically be good candidates for NO_x scrubber technology because of the potential avoidance of capital expenditure for a new scrubber as well as the operational experience in place with the scrubbers. The low-temperature oxidation technology

is capable of the 90% reductions envisioned by the incinerator ESAD originally proposed in August 2000. However, emerging technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to more established technologies and these challenges can compromise performance goals. Because of the concerns raised by the commenters about inorganic materials in the exhaust streams, the ESAD for these units is either an 80% reduction from baseline, or 0.030 lb/MMBtu.

ESAD - LIGHTWEIGHT AGGREGATE KILNS

TXI stated that the commission should re-evaluate the basis for the LWA ESAD in §117.206(c)(13)(B) of 0.76 lb NO_x/ton of product, but did not suggest an alternative ESAD. TXI asserted that Chapter 117 treats TXI's LWA kilns similar to cement kilns and stated that the kilns are more akin to hot mix asphalt plants, for which Chapter 117 does not include an ESAD. TXI stated that "neither low NO_x burners or {sic} mid-kiln firing will achieve the NO_x reductions on LWA kilns that they have been demonstrated to achieve on cement kilns." TXI stated that the "small diameter and short length of a LWA kiln correlate with a shorter residence time as compared to a long wet process cement kiln, not allowing the use of tire chips or mid-kiln firing." TXI also submitted a letter from a burner vendor in which the vendor stated that it "does not believe that a low-NO_x burner is applicable" to LWA kilns. TXI further stated that FGR "has not been tried on a rotary kiln," but also stated that "a form of FGR is currently utilized" on its LWA kilns and has been "utilized at the plant since prior to 1997." TXI also stated that "reburn technology," as described in December 2000 adoption of the existing ESADs, is more properly known as "air staging," since reburn normally involves a second source of fuel (usually natural gas, or micronized coal) downstream of the primary fuel source. TXI stated that in any case, if it were to be introduced into mid-kiln, then the operation of the cooler would be adversely affected and fuel consumption would rise.

The commission disagrees with TXI's apparent belief that the LWA ESAD in §117.206(c)(13)(B) is based entirely upon any similarity between cement kilns and LWA kilns. It is true that the commission based the ESAD in part upon information gathered from rotary kiln vendors with expertise in cement kilns and that a variety of control technologies were discussed in the preamble to the point source NO_x control strategy as adopted on December 6, 2000. However, as discussed in that preamble, the commission also based the ESAD in part upon another technology, low-temperature oxidation, which has shown to be capable of a 90% NO_x reduction. This technology is described in more detail later in this section of this preamble. The commission has re-evaluated the LWA ESAD and agrees that the mid-kiln firing and reburn technology control technologies (also known as "air staging" or "mixing air technology"), discussed in the preamble to the point source NO_x control strategy as adopted on December 6, 2000, are not applicable to LWA kilns.

Regarding TXI's claim that FGR "has not been tried on a rotary kiln," the commission notes that TXI stated that "a form of FGR is currently utilized" on its LWA kilns and has been "utilized at the plant since prior to 1997." Thus, it appears that TXI disagrees with itself. Regarding TXI's claim that low-NO_x burners are not applicable to LWA kilns, the commission notes that in an August 28, 2002 letter, TXI offered to equip its LWA kilns with low-NO_x burners, although the letter indicates that the vendor believes that a 20% NO_x reduction may be achievable but is not guaranteed. Again, it appears that TXI disagrees with itself. Even if installation of low-NO_x burners would not reduce NO_x emissions enough to meet the ESAD, one option would be to install

low-NO_x burners and use credits, which are available to TXI, to satisfy the remainder of the reductions. While the commission agrees that the low-NO_x burners may not achieve the desired reductions in LWA kilns, it notes that other technology is available to reduce emissions to well below the ESAD, as described later in this section of the preamble.

However, as also discussed later in this preamble, the ESAD for LWA kilns was based on TXI's reporting of the emissions from its LWA plant as NO, rather than NO_2. Therefore, the commission has re-evaluated the basis for the LWA ESAD in §117.206(c)(13)(B) of 0.76 lb NO_x/ton of product and has revised that ESAD to 1.25 lb NO_x/ton of product. The revised ESAD continues to represent a 30% reduction in actual emissions, despite the numerical change.

TXI asserted that tight process control with O_2, CO, and NO_x analyzers is not expected to be applicable on LWA kilns. TXI stated that O_2 control only works when one tries to combust fuel at as low an O_2 level as practical, which is not the case for LWA kilns. TXI stated that CO emissions are as likely to come from the feed, so CO would not be expected to be useful for indicating a burner problem. TXI agreed that NO_x measurement may be useful, but stated that the potential to emit NO_x by the kiln feed can be substantial and that it is probably not feasible to differentiate the source of the NO_x.

TXI did not explain why it believes that the potential to emit NO_x by the kiln feed can be substantial. The commission continues to believe that because there is an incentive to operate at the lowest temperature that product can be made in order to minimize fuel costs, knowing the instantaneous NO_x level through the use of a NO_x monitor could be used in process control such that corrective action is taken to adjust the process when the NO_x level indicates a more than adequate temperature in the kiln. Reductions in the NO_x mass emission rate would come about through reduced fuel use and the associated reduced NO_x concentration. While any such reductions, by themselves, would not be expected to be sufficient to meet the ESAD, they nevertheless could be used in conjunction with reductions from the implementation of other control measures to meet the ESAD. Use of a NO_x monitor will also enable accurate characterization of NO_x behavior, potentially leading to additional NO_x reduction strategies. The commission agrees that there will be some CO emissions associated with the feed, but believes that CO and O_2 monitoring in addition to NO_x could still provide useful information which may lead to reduced NO_x emissions.

TXI asserted that SNCR is not feasible on LWA kilns because the urea injection should be at 750 - 950 degrees Celsius for optimum conditions and that due to the very temperature sensitive nature of LWA production, this would require injection of urea through the kiln shell into the burning zone. TXI asserted that this would not be physically possible on a LWA kiln. TXI also asserted that SCR would not be applicable because the dust in the LWA gas stream would likely foul the catalyst or otherwise cause the catalyst not to react well. TXI stated that even if the dust could be removed from the gas stream at the back end of the kiln, the gas stream temperatures would have to be reheated and then injected, and that the moisture content of the LWA gas stream would cause problems with the SCR process. TXI also stated that SNCR and SCR have never been used on LWA kilns. Regarding low temperature oxidation, TXI questioned this technology's technical feasibility because it is not currently in use on any rotary kiln or on order by a rotary kiln operator.

Regarding post-combustion controls, the commission acknowledges that it is not aware of specific situations in which SCR or SNCR were considered for use on lightweight aggregate kilns. However, it is also true that there have been no lightweight aggregate kiln regulations requiring NO_x reductions that would motivate potential users to consider installation of these technologies. As Northeast States for Coordinated Air Use Management (NESCAUM) (www.nescaum.org) noted in *Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers* (Publication SS-25, September 2000), implementation of technology historically follows regulation, and not the reverse. Once clear, enforceable standards are set, the regulated community and technology vendors have proven adept at finding cost-effective solutions and then implementing them.

SNCR is not adversely affected by inorganics in the exhaust because there is no catalyst to degrade, and the NO_x reductions are favored in the high-temperature zone where SNCR is located. The commission agrees that urea injection must occur within a specific temperature window for SNCR to be effective. However, it is presently unknown whether an SNCR system could successfully inject the urea in the proper temperature zone from the end of the kiln rather than through the kiln shell because TXI has not responded to the SNCR vendor's March 2002 request for the additional information which is necessary to complete the vendor's free evaluation. Consequently, the commission is unable to make a determination with a reasonable degree of certainty concerning the applicability of SNCR to TXI's LWA kilns.

Although the use of SCR may be technically challenging due to a LWA kiln's "dirty" exhaust stream, SCR catalyst formulations are adjustable to reduce sensitivities to various catalyst poisons. SCR has been employed in boilers firing high sulfur fuel oil (up to 5.4% sulfur) and on cement kilns in commercial demonstrations in Sweden and Germany. The inorganic compounds and PM present in the exhaust streams of these applications degrade the performance more rapidly than cleaner fuels and exhaust streams, thereby shortening the life of the catalysts. Although catalyst replacement cost may be higher relative to a conventional SCR, SCR is still technically feasible.

In addition to SCR, there is an oxidation technology for NO_x reduction which has been successfully applied to a variety of full-scale commercial operations. This technology, low-temperature oxidation, injects ozone as the oxidant to form N_2O_5, which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996.

More recent full-scale commercial installations include: a natural gas-fired boiler in California, achieving 85% - 90% NO_x removal; a nitric acid pickling process in Pennsylvania, achieving 90% - 95% NO_x removal; and a 25 MW coal-fired boiler in Ohio, achieving 85% - 90% NO_x removal. In addition, full-scale commercial installation on a lead furnace in California is scheduled to occur in 2002. Recent pilot project demonstrations in HGA include a wood-fired boiler in summer 2002, and an FCCU in fall 2002. The successful full-scale commercial application of low-temperature oxidation to a coal-fired boiler at the Medical College of Ohio (MCO) in Columbus, Ohio is described in detail in *A Report on the Application of Low Temperature Oxidation for Control of NO_x*

***Emissions Introduction*, presented in Houston on February 13, 2002 at the Institute of Clean Air Companies' Forum '02 - Cutting NO_x Emissions: Operating Experience for Reducing NO_x Emissions. The commission notes that TXI's LWA kilns are already equipped with scrubbers. Consequently, they logically would be good candidates for NO_x scrubber technology because of the potential avoidance of capital expenditure for a new scrubber as well as the operational experience in place with the scrubbers. In addition, the exhaust flow rate is relatively low, which holds down the reagent costs. The MCO coal-fired boiler and a TXI LWA kiln have comparable heat inputs and exhaust flow rates. The fact that one unit is a boiler and the other is a rotary kiln is irrelevant because the exhaust stream at the scrubber inlet contains a certain level of NO_x, but the source of the NO_x is of no consequence to the control device. In other words, from the perspective of the control device, NO_x is NO_x. The specific source of the NO_x does not pose questions of technical feasibility that have not already been considered. In addition, while the MCO coal-fired boiler and TXI LWA kilns are similar in that they both have a much higher particulate loading than corresponding gas-fired boilers and LWA kilns, the relatively high particulate loading in the LWA kiln exhaust is not an issue because the existing LWA scrubber is specifically designed to control those particulate emissions.**

Regarding the issue of guarantees, emission reduction guarantees are routinely made by the emission control vendors, including the low-temperature oxidation vendor, and are set to provide a "cushion" such that the anticipated emission reductions are expected to be greater than the guaranteed emission reductions. Guarantees may also be obtained through air pollution engineering firms with offices in Houston who will operate the air pollution control system under contract so as to free up the source owner from having to operate and maintain the control system.

Because full-scale commercial applications of low-temperature oxidation have demonstrated NO_x removal efficiencies on the order of 90%, well in excess of the 30% reductions envisioned by the LWA ESAD originally proposed in August 2000, and low-temperature oxidation is especially well-suited for application to TXI's LWA kilns, it appears that a more appropriate ESAD would represent up to an 80% reduction. (An 80% reduction would take into account the likelihood that emerging technologies, like NO_x oxidation, may have more unforeseen practical challenges compared to more established technologies.) Because the commission did not propose to strengthen the ESAD, it is not adopting a more stringent ESAD at this time, although the commission may contemplate doing so in future rulemaking if additional emission reductions are necessary to bring HGA into attainment with the one-hour and/or eight-hour ozone NAAQS. Regardless, the commission continues to believe that the ESAD is technically feasible and that the ESAD would continue to be technically feasible even if the ESAD represented a much greater reduction, such as 80%.

The wide chasm between the reductions represented by the LWA ESAD and the NO_x removal efficiencies demonstrated by low-temperature oxidation provides a significant allowance for the likelihood that emerging technologies, like NO_x oxidation, may have more unforeseen practical challenges compared to more established technologies. Because of the concerns raised by TXI regarding the company's error in reporting its NO_x emissions, described earlier in this preamble under the GENERAL COMMENTS heading, the commission has revised the LWA ESAD from

0.76 lb NO_x per ton of product to 1.25 lb NO_x per ton of product. The revised ESAD continues to represent a 30% reduction in actual emissions, despite the numerical change, because the original LWA ESAD of 0.76 lb NO_x per ton of product was based on TXI's erroneous reporting of NO_x as NO rather than NO_2. Nevertheless, the commission continues to believe that the current LWA ESAD of 0.76 lb NO_x per ton of product is technically feasible.

LOW ANNUAL CAPACITY FACTOR ESAD
Reliant stated that the proposed implementation of the alternate ESADs inadvertently does not include the low annual capacity factor ESAD for utility boilers, auxiliary steam boilers, and stationary gas turbines currently found in §117.106(c)(4). Reliant stated that the alternate ESADs were not intended to substitute for this low capacity factor ESAD, as it would increase the stringency of the emission specification applicable to these few sources by a factor of two. Reliant stated that the low capacity factor ESAD rate affects a minimal amount of emissions, does not alter the 535 tpd NO_x emission budget, and should remain in place.

In fact, the proposed deletion of §117.106(c)(4) was not inadvertent. Instead, the commission proposed to delete the current ESADs in §117.106(c)(1) - (4) and replace them with the alternate ESADs of §117.106(c)(5)(A) - (C) which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC. The alternate ESADs provided by BCCA-AG do not include a low annual capacity factor ESAD for electric utilities. It should be noted that Reliant is one of BCCA-AG's member companies and presumably had input into BCCA-AG's development of the alternate ESADs.

GHASP commented on §§117.106(c)(4), 117.206(c)(17), and 117.475(c)(6), which include an ESAD for a unit with an annual capacity factor of 0.0383 or less. GHASP requested that the commission evaluate whether these units would be more likely to operate during periods conducive to the formation of ground-level ozone, and that if so, the commission should adjust its future case emission inventories to account for the higher emissions allowed from these units than would be expected based on annual or ozone season averaging techniques.

The ESAD is the lower of any applicable permit limit or 0.06 lb/MMBtu for any unit with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation. There is no reason to believe that units which qualify for this ESAD would be more likely to operate at any particular time.

MODELING
Louisiana-Pacific commented that its Cleveland plywood manufacturing and sawmill complex is located approximately five miles south of the northernmost boundary of HGA, approximately 50 miles northeast of Houston. Louisiana-Pacific stated that the NO_x emissions from its wood-fired boiler, alone or combined with emissions from all other wood-fired boilers in HGA, are “insignificant in terms of impact on ozone formation” in HGA. TXI similarly stated that its Clodine LWA plant is located only nine miles southeast of Waller County “which is not in the HGA,” approximately 20 miles west of downtown Houston and 30 miles from the ship channel. TXI stated that the NO_x emissions from its LWA plant are an insignificant contributor to NO_x emissions in HGA and that there is “no evidence that

meeting {the ESAD} would have any real beneficial impact on ambient ozone concentrations in the areas where monitors have indicated that the ozone standard has been exceeded."

Even though wood-fired boiler and LWA kiln emissions form a relatively small fraction of the total emissions in HGA, the same can be said of most categories of emission sources. The commenters' logic of allowing minimal (or no) reductions from a source sector because it individually contributes only marginally to the area's ozone problem would cumulatively result in an inadequate plan for the area's attainment of the ozone standard due to insufficient emission reductions. Because significant contributions to air pollution occur throughout the HGA area, reductions from sources within Houston alone will not be enough to meet federal air quality standards.

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

Furthermore, it is inequitable to create a protected source category such as wood-fired boilers or LWA kilns which is not subject to the Chapter 101 mass emissions cap and trade program. Indeed, such a protected source category would permit continued growth in emissions, thereby jeopardizing the SIP.

In addition, although the percentage contribution is small, wood-fired boilers and LWA kilns by themselves are nonetheless "major sources" (defined by the 1990 FCAA Amendments as having the potential to emit 25 tpy for sources in HGA). For source categories such as wood-fired boilers and LWA kilns, which have relatively few affected sources, comparing these emissions to the total emissions of all regulated sources or to emissions from specific large sources is not meaningful or appropriate as a criterion for control. Finally, in response to TXI's comment that Waller County is not in HGA, it should be noted that Waller County has been part of the eight-county HGA ozone nonattainment area since the classification of HGA as Severe-17 for ozone nonattainment over eleven years ago, as codified in 40 CFR §81.344. (See the November 6, 1991 issue of the *Federal Register* (56 FR 56694)). Consequently, Waller County has been included for over eleven years as one of the eight counties comprising the HGA ozone nonattainment area, as specified in the definition of "applicable ozone nonattainment area" in §117.10(2).

CO AND AMMONIA EMISSIONS

It has come to the commission's attention that the references to §50.39 and to filing a motion for reconsideration should be deleted from §§117.121(b), 117.151(b), 117.221(b), and 117.481(b) because §50.39 only applies to any application that is declared administratively complete before September 1, 1999. The references to §50.139, which applies to any application that is declared administratively complete on or after September 1, 1999, are appropriate and have been retained.

GHASP supported the proposed ammonia limit for electric utilities in east and central Texas and monitoring requirements and requested that the commission perform an initial determination as to the likely impact on $PM_{2.5}$ concentrations as a result of likely ammonia emissions. GHASP further stated that the proposed standard of ten ppmv ammonia should be based on potential health effects as well as "good engineering practice."

The proposed ammonia limit of ten ppmv in §117.135(2)(B) is consistent with the existing ammonia limit of ten ppmv in §§117.106(d)(2), 117.206(e)(2), and 117.475(i). The existing ammonia limit of ten ppmv 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* (June 1998), prepared for Northeast States for Coordinated Air Use Management and Mid-Atlantic Regional Air Management Association (will be referred to as NESCAUM/MARAMA). The utility boiler operators cooperated in the development of this report by providing actual project cost, operating cost, as well as operating experience.

The commission selected an allowable ammonia slip of ten ppmv for post-combustion controls in order to balance the implementation of an effective control strategy for NO_x reduction against concern that significantly increased ammonia emissions will enhance $PM_{2.5}$ particle formation. Ammonia emissions can contribute to the production of particulate sulfate, nitrate, and ammonium which may create health effects concerns related to $PM_{2.5}$. These particulates can also degrade visibility. Current monitoring data indicate that additional ammonia emissions could increase particulate sulfate, and particulate nitrate and ammonium might also increase with a ten ppmv ammonia slip. However, the amount of any potential increase is uncertain, and until aerosol modeling is used to calculate $PM_{2.5}$ mass concentrations, the exact impact of increased ammonia emissions cannot be known. However, based on current information, it appears that most, if not all, of the NO_x reductions required of electric utilities in east and central Texas by §117.135(1) will be achieved through combustion modifications, rather than through installation of SCR or SNCR. Therefore, minimal impact is anticipated on $PM_{2.5}$ concentrations as a result of ammonia emissions from electric utilities in east and central Texas because combustion modifications, the predominate control strategy being implemented at these sources, do not result in an increase in ammonia emissions.

CPS stated that the ten ppmv ammonia limit in §117.135(2)(B) should clearly state that the rule is subject only to units equipped with SCR or SNCR, since ammonia is only associated with those types of NO_x controls.

The commission agrees that §117.135(2)(B) is intended to apply to units which inject urea or ammonia into the exhaust stream for NO_x control and has revised §117.135(2)(B) accordingly. Likewise, the commission has made corresponding clarifications to the ten ppmv ammonia limit in §§117.106(d)(2), 117.206(e)(2), and 117.475(i)(2).

TXI stated that SCR and SNCR can also increase CO, nitrous oxide (N_2O), and ammonia emissions and expressed concern that an ammonium bisulfate stack plume could result.

Emissions due to ammonia slip and potential particle formation are addressed earlier in this preamble under the CO AND AMMONIA EMISSIONS heading, in addition to being discussed in greater detail in the ANALYSIS OF TESTIMONY sections of the preambles to the Chapter 117 rulemakings which were published in the January 12, 2001 and October 12, 2001 issues of the *Texas Register*. TXI did not provide documentation of its claim that increases in CO and N_2O emissions could occur with operation of SCR or SNCR. A 1999 European report on nitrous oxide cited two references which discussed SCR and SNCR's effect with regard to nitrous oxide. The Japanese reference cited in the report saw no nitrous oxide increase with SCR in actual measurements and little with SNCR.

GHASP supported the proposed CO limit for EGFs in east and central Texas and monitoring requirements. AECT, CPS, and TXU opposed the proposed CO limit for EGFs in east and central Texas, although AECT and TXU agreed that the proposed 400 ppmv CO limit is an appropriate limit for gas-fired EGFs in east and central Texas. AECT and TXU questioned why, from an environmental standpoint, it is important to "have *any* limits on CO emissions" in east and central Texas or what problem the limit is designed to mitigate. (AECT's and TXU's emphasis supplied.) AECT and TXU stated that no part of Texas (except El Paso) has been designated as nonattainment for the CO NAAQS and that they are not aware of any studies or analysis which suggest that any increase in CO emissions that may result from NO_x controls on EGFs will cause or threaten a violation of the CO NAAQS or otherwise harm human health or the environment. CPS stated that Bexar County has never exceeded the CO NAAQS, that point sources in the local Bexar County airshed contribute less than 2% to the total CO emissions of Bexar County, and that only about 18 tpd out of a total of 1,180 tpd of CO emissions are contributed by point sources in Bexar County (1.5% of total CO emissions). CPS further stated that in the counties surrounding Bexar County, point sources only contribute about 3.0% of the total CO emissions.

The commission appreciates GHASP's support for the proposed CO limit for EGFs in east and central Texas and monitoring requirements. The commission also appreciates AECT's and TXU's support for the proposed 400 ppmv CO limit for gas-fired EGFs in east and central Texas. While it is true that El Paso is currently the only CO nonattainment area in Texas, CO is still an air pollutant of concern, as described in the following paragraphs.

The proposed CO emission limits of §117.135(2) address pollutants which may increase as an incidental result of compliance with the existing NO_x limits. With CO, the available literature suggests that NO_x control technology can be operated in most cases in such a manner as to avoid large CO increases. The commission has concerns that if CO emissions are allowed to increase without restrictions (or with higher-than-necessary limits) in every case, CO increases far larger than reasonable may result. As noted on page 1.1-4 of EPA's *AP-42, Compilation of Air Pollutant Emission Factors, Volume I* (1998), "the rate of CO emissions from combustion sources depends on the fuel oxidation efficiency of the source. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or is not well-maintained, the resulting concentrations of CO (*as well as organic compounds*) may increase by several orders of magnitude." (Emphasis added.)

The commission's intent in proposing a CO emission limit was to ensure that retrofit NO_x controls, which have the potential to cause a CO emissions increase, will not result in excessive CO emission levels. CO is a product of incomplete combustion, is a criteria pollutant, and is also known to play a limited role in ozone formation. As an organic compound, CO has a lower photochemical reactivity (i.e., ozone formation potential) than methane or ethane, but it is, nonetheless, an emission input in the photochemical modeling due to the large quantity of actual emissions, primarily from mobile sources. VOC emissions are also products of incomplete combustion, and may concurrently increase with CO increases. Any VOC increases associated with higher CO emissions are of concern to the commission because of their potential to exacerbate ozone formation.

The concerns resulting from high CO and unburned hydrocarbon emissions are associated with short-term averaging times: one-hour and eight-hour ozone and CO NAAQs, as well as hourly health effects evaluations. The data shows that many of the units in east and central Texas can meet a 400 ppmv CO standard and many cannot. The purpose of the standard is not simply to put a number on the books which can be met by the highest emitters, or to assure that only one unit needs to request an alternative limit, but to effectuate reductions. As noted earlier in this preamble, the commission has revised §117.135(2) to delete the CO limit for EGFs in east and central Texas.

AECT and TXU stated that the CO limit is identical to the CO limit previously adopted for DFW and HGA EGFs. AECT and TXU questioned why it is desirable to have the CO limit for EGFs in east and central Texas be consistent with the DFW and HGA CO limit of 400 ppmv when "coal and gas-fired units do not have similar emissions profiles and do not respond to emissions controls in a similar manner." AECT and TXU stated that the 400 ppmv limit "that applies to gas-fired units in ozone non-attainment areas" is not relevant for coal-fired units in east and central Texas and noted that the NO_x limit is not the same for the two areas.

In fact, the existing 400 ppmv CO limit for EGFs in BPA, DFW, and HGA applies to both gas-fired and coal-fired units. Four of the EGFs in HGA are coal-fired, with two being tangential-fired and two being wall-fired. It is true that the NO_x emission specifications for EGFs in DFW and HGA, while not equivalent to each other, are more stringent than for EGFs in east and central Texas, while the NO_x emission specifications for EGFs in BPA are similar to those for EGFs in east and central Texas. Nevertheless, experience in these areas has shown that the 400 ppmv limit is achievable. For example, a recent report, *Lower NO_x/Higher Efficiency Combustion Systems*, authored by A.D. LaRue and G. Nikitenko of Babcock and Wilcox and H.S. Blinka and R.H. Hoh of Reliant, included information about the CO levels achieved subsequent to low-NO_x burner retrofits of two wall-fired coal-fired units at Reliant's Parish power plant. Unit 6 was retrofitted in mid-2000, and Unit 5 was retrofitted in 2001, which reduced NO_x emissions to 0.17 lb/MMBtu (51% reduction) and 0.15 lb/MMBtu (50% reduction), respectively, which is comparable to NO_x emission specification of 0.0165 lb/MMBtu (50% reduction) for coal-fired units in §117.135(1)(A)(ii). The report states that for Unit 6, "CO emissions were about 100 ppm at full load and negligible at reduced loads" and that for Unit 5, "full load CO emissions were typically 50 to 100 ppm and negligible at part loads."

Another report, *Retrofit Low NO_x Experience for Tangentially-Fired Boilers – 2002 Update*, authored by A. Kokkinos, D. Wasyluk, and M. Boris of Babcock & Wilcox, included an evaluation of the effect of NO_x combustion modifications (staged combustion) on CO emissions at a number of tangential coal-fired utility boilers. Before implementation of combustion modifications which reduced NO_x emissions by over 50%, the CO emissions were reported to be less than 30 ppm at 3% O_2 for each of the seven units. After the combustion modifications were made, the CO emissions increased somewhat, ranging from 30 ppm to 110 ppm at 3% O_2. In addition, Unit 7 at Reliant's Parish power plant is a tangential coal-fired unit and has been subject to NO_x RACT since November 15, 1999 (final compliance date), and there has been no indication that the unit has been unable to meet the 400 ppm CO limit.

While numerous units can easily meet the proposed CO limit of 400 ppm, including tangential lignite-fueled, and wall and tangential coal-fired utility boilers in Texas, as described in the preceding paragraphs and in literature, the commission notes that certain coal-fired units in east and central Texas have extremely high CO emissions and therefore would be unable to meet a 400 ppm CO limit. A variety of reasonable methods to reduce CO emissions from these units include boiler tuning over time by operators and evaluation of approaches by knowledgeable third parties such as NO_x control vendors. In addition, application of neural network technology to optimize for CO may be effective. Because it is unclear if these high-emitting units would be able to meet a 400 ppm CO limit even after the application of these methods to reduce CO emissions, the commission has revised §117.135(2) to delete the CO limit. The commission may revisit the issue in the future, however. Therefore, the commission encourages owners and operators of the high-emitting units to voluntarily take action to reduce their CO emissions.

AECT and TXU stated that all EGFs in east and central Texas have already been or soon will be subject to CO emissions limits under the commission's permit application and renewal process. AECT and TXU recommended that the permitting process be used to limit CO emissions, rather than the proposed 400 ppmv CO limit and the availability of alternate case-specific limits. AECT and TXU stated that the commission has issued one permit and is reviewing several permit renewal applications for EGFs in east and central Texas that include CO limits significantly higher than 400 ppmv.

The permit renewal program does not require updating best available control technology (BACT) and does not provide a mechanism for obtaining systematic emission reductions. In addition, because permit renewals are staggered over a ten- to 15-year cycle, efforts to implement system-wide improvements would be difficult to focus over so many years, even if the regulations provided for it. The reduction of area-wide high CO through best engineering practices is best achieved by a focused, system-wide effort over a one- to two-year period, followed by establishing individual limits which have been shown to be achievable in a cost-effective manner. The rulemaking process is best suited for accomplishing this type of targeted improvement over time.

AECT stated that most coal-fired EGFs in east and central Texas currently exceed the proposed 400 ppmv CO limit and are expected to continue to do so after the planned NO_x controls have been installed. TXU stated that all nine of its coal-fired EGFs in east and central Texas currently exceed the proposed 400 ppmv CO limit and are expected to continue to do so after the planned NO_x controls have been installed. AECT and TXU acknowledged that the proposed §117.151 provides for the availability of case-specific specifications, but asserted that this alternative actually challenges the validity of the proposed CO limit for coal-fired units since they believe that most or all coal-fired EGFs will exceed the proposed 400 ppmv CO limit. AECT and TXU stated that there is little value in promulgating a 400 ppmv CO limit if most coal-fired EGFs in east and central Texas cannot meet that standard and instead must pursue an alternate CO limit.

When the commission includes the availability of alternate case-specific specifications, alternate means of control, alternate RACT determinations, etc., it does so to provide flexibility to the regulated community because it is impossible for the commission to anticipate and address every unique circumstance in the rules, not because the underlying standards are flawed. The commission agrees that the CO limit should be one that most units can meet, with case-by-case evaluation of units that have special circumstances that prevent them from meeting the CO limit.

AECT and TXU stated that most coal-fired EGFs can achieve 775 ppmv CO at 7.0% 0_2 on an annual basis while also meeting the NO_x limits of §117.135(1), and TXU stated that it would need to apply for an alternative CO limit for only one unit under that standard. AECT and TXU stated that a 7.0% O_2 adjustment is appropriate for coal-fired EGFs because excess oxygen levels in the exhaust from coal-fired units typically run at levels of 6.0% to 8.0%, as compared to gas-fired units that typically run at about 3.0%. AECT and TXU stated that coal-fired EGFs need a higher limit and longer averaging time. AECT and TXU further stated that the coal combustion process is affected by many factors that cause high variability in CO levels, such as fuel Btu content, ambient air temperature, unit load, excess oxygen, fuel grind, fuel slagging properties, fuel moisture, fuel blend, and other variables that can change rapidly. AECT and TXU stated that some of these factors can be seasonal and asserted that at least a 30-day averaging period is necessary as a result. As an alternative, AECT and TXU recommended an annual averaging period, which they stated would be consistent with the NO_x system cap available under §117.138.

The proposed CO emission limits of §117.135(2) address pollutants which may increase as an incidental result of compliance with the existing NO_x limits. With CO, the available literature suggests that NO_x control technology can be operated in most cases in such a manner as to avoid large CO increases. The commission has concerns that if CO emissions are allowed to increase without restrictions (or with higher-than-necessary limits) in every case, CO increases far larger than reasonable may result. As noted on page 1.1-4 of EPA's *AP-42, Compilation of Air Pollutant Emission Factors, Volume I* (1998), "the rate of CO emissions from combustion sources depends on the fuel oxidation efficiency of the source. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or is not well-maintained, the resulting concentrations of CO (*as well as organic compounds*) may increase by several orders of magnitude." (Emphasis added.)

The commission's intent in proposing a CO emission limit was to ensure that retrofit NO_x controls, which have the potential to cause a CO emissions increase, will not result in excessive CO emission levels. CO is a product of incomplete combustion, is a criteria pollutant, and is also known to play a limited role in ozone formation. As an organic compound, CO has a lower photochemical reactivity (i.e., ozone formation potential) than methane or ethane, but it is nonetheless an emission input in the photochemical modeling due to the large quantity of actual

emissions, primarily from mobile sources. VOC emissions are also products of incomplete combustion, and may concurrently increase with CO increases. Any VOC increases associated with higher CO emissions are of concern to the commission because of their potential to exacerbate ozone formation.

Regarding the CO averaging period, the commission does not agree that a 30-day rolling average or annual average should apply for CO limits. The one-hour averaging period for CO is due to the direct relationship between CO emissions and the primary, one-hour averaging period of the CO NAAQS. In contrast, the relation between NO_x emissions and the ozone standard is not as well defined but is thought to be dependent on longer term emissions.

The concerns resulting from high CO and unburned hydrocarbon emissions are associated with short-term averaging times: one-hour and eight-hour ozone and CO NAAQs, as well as hourly health effects evaluations. The data shows that many of the units in east and central Texas can meet a 400 ppmv CO standard and many cannot. The purpose of the standard is not simply to put a number on the books which can be met by the highest emitters, or to assure that only one unit needs to request an alternative limit, but to effectuate reductions. As noted earlier in this preamble, the commission has revised §117.135(2) to delete the CO limit for EGFs in east and central Texas.

AECT and TXU stated that the commission must provide a reasoned justification for the proposed CO limit in east and central Texas, showing that the rule is a reasonable means to a legitimate objective. AECT and TXU stated that they were not aware of any studies by the commission suggesting that increases in CO from enhanced NO_x controls on electric utility boilers will threaten a violation of any NAAQS or otherwise harm human health or the environment. AECT and TXU asserted that the proposal lacks any objective, let alone a legitimate objective, in proposing a CO limit.

As noted earlier in this preamble, the commission has revised §117.135(2) to delete the CO limit for EGFs in east and central Texas. The objective of the commission's proposal to limit CO was to ensure that the NO_x controls did not unnecessarily increase CO, an identified harmful, federal "criteria" air pollutant, and other products of incomplete combustion from the affected power plants. Other products of incomplete combustion which tend to increase with CO include reactive organic compounds, which contribute to ozone formation, and hazardous organic compounds, which have much lower impact thresholds of concern than CO. In the absence of specific studies, the commission considers it a worthwhile objective to achieve significant reductions, or avoidance of significant increases of CO, if it can be achieved at little additional effort by owners of emitting facilities.

The information available at proposal, consisting of a number of recently published articles concerning NO_x retrofits of some of the units in east and central Texas, indicated that the proposed limit was a reasonable way to ensure that CO increases resulting from installation of the NO_x controls would be minimized. After the rule was proposed, TXU provided CO emissions data from their lignite-fired boilers in east and central Texas which show that their nine units would not currently meet a CO limit of 400 ppm at 3.0% O_2 and that the emissions have increased significantly after installation of combustion controls for NO_x reduction. Because much higher

CO emissions are so extensive among the 26 affected solid-fueled units, it is apparent that minimizing CO will take greater effort than previously understood. Operational adjustments are probably capable of significantly reducing the emissions in a number of cases, but in order to achieve these results at little additional cost, as AECT and TXU pointed out, more time will be required to gain operating experience with post-NO_x control boiler performance. Because the CO emissions are so much higher than previously understood, it will be necessary to assess whether the CO increases include significant increases in reactive organic compounds, which could limit the effectiveness of the ozone control strategy. Gathering information on VOC emissions will also require additional time.

The commission has provided a "reasoned justification" for the rules in this adoption package as required by Texas Government Code, §2001.033. The requirement for a reasoned justification applies to the agency order finally adopting a rule. The standard for compliance with the reasoned justification requirement is substantial compliance, as determined by the legislature, which amended the reasoned justification requirement in 1999. The commission has provided the factual, policy, and legal bases for the rule, as required. Texas Government Code, §2001.024, requires only "a brief explanation" of the rules upon proposal in addition to other elements such as the fiscal note and public benefit evaluations. Both the rule proposal and adoption meet all of the requirements of the APA.

Austin Energy noted that the proposed CO limit for electric utilities in east and central Texas in §117.135(2)(A) is based on either 3% O_2 (for boilers) or 15% O_2 (for gas turbines) and commented that it would be helpful if formulas were included which demonstrate how to make this conversion.

It is standard practice in the field of air pollution control to reference concentration limits to a flue gas oxygen concentration, to address the effects of dilution. The reference conditions of 3.0% O_2 for boilers and 15% O_2 for gas turbines on a dry basis are standard conventions in the field of air pollution control. An equivalent alternate standard based on heat input was included in the proposal to simplify compliance tracking for monitoring systems which are based on carbon dioxide as the diluent. The equation could be added into Chapter 117 definitions at some point in the future. In the meantime, the commission notes that 40 CFR Part 60, Appendix A, Reference Method 19 contains the O_2 correction equation to 15%. Also, as noted earlier in this preamble, the commission has revised §117.135(2) to delete the CO limit for EGFs in east and central Texas.

BP suggested that the rule should clarify that ammonia slip is a separate limitation from individual emission sources that are authorized to emit ammonia through other applications, such as in an ESP for particulate control on an FCCU.

Ammonia which is already present in the exhaust stream when urea or ammonia is injected into the exhaust stream for NO_x control would count toward the ammonia emission limit. In the situation described by the commenter, it would not be practical to attempt to isolate multiple sources of ammonia emissions.

BP and Phillips stated that §117.206(e)(2), which limits ammonia emissions to ten ppmv, should be changed to 20 ppmv for FCCUs. BP and TxOGA stated that SO_3/H_2SO_4 formation is more prevalent with SCR technology on FCCUs due to the higher SO_2 present in the flue gas. BP and TxOGA stated that it is better for the environment to make neutral pH PM (e.g. ammonia sulfate) by increasing the ammonia slip limit from ten to 20 ppmv for FCCUs, as opposed to a higher concentration of SO_3/H_2SO_4 that results in acidic PM (e.g., acid rain). BP and TxOGA stated that the commission should recognize this trade-off by modifying the ammonia slip as suggested.

It is desirable to minimize ammonia emissions because ammonia emissions create $PM_{2.5}$, another form of air pollution. The existing ammonia limit of ten ppmv 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* (June 1998), prepared for NESCAUM/MARAMA. The utility boiler operators cooperated in the development of this report by providing actual project cost, operating cost, as well as operating experience.

The commission does not expect most SCR projects to undergo BACT review because the Standard Permit for Pollution Control Projects in 30 TAC §116.617 should be available for use by SCR projects with a 30-day review time period. The only additional requirement because of the ammonia would be a demonstration to the "satisfaction of the executive director" that there are no "significant health effects concerns resulting from an increase in emissions of any air contaminant other than those for which a National Ambient Air Quality Standard has been established." This requirement is in §116.617(1) and can normally be satisfied by using the EPA Screen Model. Using the standard permit should eliminate much of the permitting time associated with a BACT review, provided that the ammonia emissions from the storage, handling, and slip do not create any health concerns.

It should be noted that §117.114(b) and §117.214(b)(1) require testing as specified in §117.111 and §117.211, respectively, which in turn require testing under §117.111(b) and §117.211(a)(2), respectively, for ammonia emissions on units which inject urea or ammonia into the exhaust stream for NO_x control. Similarly, §117.479(e)(2) requires testing for ammonia emissions on units which inject urea or ammonia into the exhaust stream for NO_x control. This testing is necessary to ensure compliance with the limit on ammonia emissions.

The commission also notes that NO_x control technology which does not result in ammonia emission is available. Specifically, there is an oxidation technology for NO_x reduction which has been successfully applied to a variety of full-scale commercial operations. This technology, low-temperature oxidation, injects ozone as the oxidant to form N_2O_5, which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. More recent full-scale commercial installations include: a natural gas-fired boiler in California, achieving 85% - 90% NO_x removal; a nitric acid pickling process in Pennsylvania, achieving 90% - 95% NO_x removal; and a 25 MW coal-fired boiler in Ohio, achieving 85% - 90% NO_x removal. In addition, full-scale commercial installation on a lead furnace in California is scheduled to occur in 2002. Recent pilot project demonstrations in HGA include a wood-fired boiler in summer 2002, and an FCCU in fall 2002.

Section 117.221 allows alternative emission specifications to be established on a case specific basis for ammonia. The commission is excluding this related pollutant limit from the SIP in order to simplify the approval process for alternative emission specifications. This step will eliminate the need for case specific SIP revisions by the EPA to complete the approval of an alternate ammonia limit. If NO_x emissions from an FCCU are controlled through injection of urea or ammonia and the FCCU is unable to meet the ten ppmv ammonia limit, §117.221 is available to the owner or operator of the FCCU to establish a case specific ammonia limit. The commission believes that the existing ammonia emission limit of ten ppmv is appropriate for the reasons described in the preceding paragraphs. Not many of the 13 FCCUs in HGA are using ammonia to condition their ESPs. The purpose of the standard is not simply to put a number on the books which can be met by the highest emitters, or to assure that only one unit needs to request an alternative limit, but to effectuate reductions. Therefore, the commission has not revised the ammonia limit.

BP recommended that the rule clarify that the ammonia slip limit is specific to units equipped with SCR.

The ammonia slip limit is intended to apply to units equipped with SCR, SNCR, or SCR/SNCR hybrids for NO_x control. The commission has revised §§117.106(d)(2), 117.135(2)(B), 117.206(e)(2), and 117.475(i)(2) to clarify that the ammonia slip limit applies to units which inject urea or ammonia into the exhaust stream for NO_x control.

GHASP supported the exclusion of the alternate case-specific specifications for CO and ammonia emissions from the SIP, as long as health considerations are maintained when considering emission limits and monitoring requirements for these pollutants. Sierra-Houston stated that the commission should develop criteria that will be considered in evaluating requests for alternate case-specific specifications for CO and ammonia emissions in order to avoid favoritism to any particular company.

The commission agrees with GHASP's comment. The commission will take into account health considerations in addition to technological and economic factors in reviewing requests for alternate case-specific specifications for CO and ammonia emissions, thereby avoiding favoritism to any particular company.

Dow questioned why §117.221(a)(4) and §117.481(a)(4) specify that "The executive director: {4} is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section."

Executive director is defined in 30 TAC §3.2 as "the executive director of the commission, or any authorized individual designated to act for the executive director." The reference to the Engineering Services Team is necessary to clearly designate where within the agency requests for alternate case-specifications for CO and ammonia should be directed and who will review and respond to such requests.

MONITORING REQUIREMENTS
No comments were received on the totaling fuel flow meter requirements of §117.113(h). However, it has come to the commission's attention that inclusion of an alternative to installation of totalizing fuel flow meters for units that operate infrequently would be appropriate.

Specifically, the commission has revised §117.113(h) by specifying that in lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. It only makes sense to apply this alternate technique on units that run only at full load or units that operate infrequently. Application to units that run at partial load more frequently would overestimate emissions. While there may be some slight overestimation of NO_x emissions for units that run only at full load or units that operate infrequently, it is offset by the savings associated with not having to install fuel flow monitors on units with minimal operation.

Pavilion stated that the monitoring requirements should be stand-alone and recommended that the rules include the commission's PEMS Draft Protocol and the appropriate EPA requirements in order to clarify the monitoring requirements and agency policies to the regulated community and the commission's field operations and enforcement groups.

The commission's PEMS Draft Protocol is available to the regulated community as well as enforcement personnel in order to clarify the PEMS requirements for both regulations and for NSR permits. In addition, the EPA monitoring requirements are readily available. Therefore, the commission does not believe that it is necessary to include the PEMS Draft Protocol and the appropriate EPA requirements in the rules.

Austin Energy commented on the proposed CO monitoring for EGFs in east and central Texas in §117.143(b) and stated that all of Austin Energy's gas-fired units have CO monitors that were designed to control the combustion process and not for emissions compliance purposes. Austin Energy stated that the data from these analyzers is recorded manually, and therefore would not be considered CEMS. Austin Energy suggested the addition of an option in which it would be allowed to use the hourly data from the process control CO monitors to demonstrate compliance if it can demonstrate that the CO emissions are less than 40 ppm (24-hour average), with an approved reference method used (perhaps during an annual RATA) as confirmation.

Based on Austin Energy's comments, its EGFs do not have a CO problem. The proposed CO monitoring is limited to periodic testing and periodic checks, so Austin Energy does not need to make this correlation against the process monitor to satisfy the rule. However, if Austin Energy chooses to do so, it would provide the inspector credible evidence beyond the rule requirements that it is in compliance. In any case, the commission has revised §117.143(b) such that CO monitoring is no longer required. However, the commission may revisit the issue in the future.

CPS stated that it believes it is not technically practicable or economically reasonable to manually sample CO "after manual combustion tuning or manual burner adjustments conducted for the purpose of minimizing NO_x emissions," and that consequently the proposed §117.143(b)(1) essentially mandates CO CEMS or PEMS at each EGF. CPS stated that NO_x formation is dependent on temperature, oxygen, and other factors that are routinely monitored and adjusted by plant personnel such that minor adjustments to minimize NO_x occur on a regular basis. CPS stated that portable process CO analyzers are used by plant operators to the extent necessary to optimize fuel combustion, maximize boiler efficiency, and minimize incomplete combustion. CPS stated that it is not practical or reasonable for plant operators to sample for CO each time it makes minor, routine adjustments to reduce NO_x. CPS further stated that boilers using neural nets designed to optimize emissions would be continuously adjusting for NO_x using a computerized system, and therefore would be unable to meet the proposed sampling requirement. CPS suggested that sampling CO each year during the annual RATA as proposed in §117.143(b)(2)(B) would be adequate for addressing CO emissions from EGFs in east and central Texas.

As proposed, §117.143(b)(2)(A) specifies that CO sampling is to be conducted whenever either of the following occur: 1) NO_x emissions are sampled with a portable analyzer; or 2) NO_x emissions measured by CEMS or predicted by PEMS are lower than levels for which CO emissions data were previously gathered. Therefore, CO is only tested with a portable analyzer when the owner finds it technically and economically practical to test for NO_x. Also, §117.143(b)(2)(A) only applies to manual tuning, so the automated tuning would not be subject to CO testing. While the rule does not address the question of where the set points on the neural network control should be allowed to go and how little O_2 is allowed, the neural net could be trained with data including one-time CO stack sampling, in similar manner as a PEMS is trained. As described earlier in this preamble, the commission has revised §117.143(b) such that CO monitoring is no longer required. However, the commission may revisit the issue in the future.

CPS stated that acid rain peaking units should not be subject to the CO limit and should not have to monitor or analyze for CO because the existing §117.143(d)(1) allows acid rain peaking units to utilize 40 CFR Part 75, which provides an alternate method of measuring NO_x in lieu of installing a CEMs. CPS recommended that because the current rules do not require NO_x monitoring for peaking units, the proposed rules for CO monitoring should likewise not apply.

The commission agrees that acid rain peaking units, as defined in 40 CFR §72.2, will operate relatively few hours. Therefore, it would be reasonable to excluded these units from §117.143(b) if the commission adds a CO limit in the future.

CPS noted that the proposed §117.113(c)(3)(C) and §117.213(e)(4)(C) for CEMS in HGA provide that exhaust streams of units which vent to a common stack do not need to be analyzed separately. CPS recommended that similar language be added to §117.143(c).

The existing CEMS requirements were initially developed for the NO_x RACT rules, with which affected units typically comply by meeting an individually enforceable limit, either directly through §117.105 or §117.205 or through averaging in accordance with §117.107 or §117.207. The language which CPS referenced is appropriate in HGA because compliance with §117.106 or §117.206 and the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 is demonstrated through a limit on total annual tons of NO_x emitted to the atmosphere, such that it would be more effective for the NO_x CEMS requirements to be linked to stacks, rather than individual units.

For units which are included in a system cap under §117.138, it likewise is more effective for the NO_x CEMS requirements to be linked to stacks, rather than individual units. Therefore, the commission has added a new §117.143(c)(3) which enables the sharing of CEMS in this manner. The new §117.143(c)(3) also specifies that all bypass stacks must be monitored in order to quantify

emissions directed through the bypass stack. This is necessary because under the system cap, all NO_x emissions are considered, including those from startup, shutdown, upset, and maintenance activities at affected units. The new §117.143(c) further specifies that exhaust streams of units which vent to a common stack do not need to be analyzed separately.

Dow questioned why §117.213(e)(1)(B)(i) referred to "Performance Specification 2" while §117.213(f)(5)(A)(i)(I) referred more specifically to "Performance Specification 2, subsection 4.3."

The previous version of Performance Specification (PS) 2 included the CEMS relative accuracy requirement in Section 4.3. The current version of PS 2 (see the October 17, 2000 issue of the *Federal Register* (65 FR 62130)) has been reformatted and the CEMS relative accuracy requirement is found in subsection 13.2 and in the associated specification requirements that support that measurement. Since a PEMS can not be subjected to the calibration drift test of subsection 13.1, it has not been referenced in §117.213(f)(5)(A)(i)(I). Likewise, the PS 3 requirement under §117.213(f)(5)(A)(i)(II) has been changed to reference subsection 13.2, and the PS 4 requirement under §117.213(f)(5)(A)(i)(III) has been changed to reference subsection 13.2.

Pavilion commented on the proposed revision to §117.213(e)(1)(B)(i) and (f)(5)(A)(i) and (C)(iii)(II) and stated that the proposed RATA requirement for NO_x CEMS and PEMS should be six ppmv (dry) or equivalent, based upon "Uncertainty in Gas Turbine NO_x Emission Measurements" (Wilfred S.Y. Hung and Alan Campbell, authors; date unknown) which analyzed the uncertainty of the techniques used to perform a NO_x RATA. Pavilion stated that in comparison, the 40 CFR Part 75 NO_x RATA requirements for low-emitting NO_x units is 0.020 lb/MMBtu, which corresponds to approximately 16.5 ppm for boilers and furnaces (assuming 3% O_2) and 5.5 ppm for turbines. Pavilion stated that to address absolute accuracy of the predicted CEMS and PEMS results, a t-test should be performed to determine if a bias should be applied to CEMS and PEMS output. Pavilion stated that this bias adjustment should be allowed to be either a positive or negative since allowing only positive adjustments to the results would be "punishing industry."

The commission is unaware of specific instances where a new monitor has failed a low-level RATA even to levels as low as a 2.5 ppmv emission limit. However, the commission considered the fact that most of the monitors for new units were in prime condition and with age may not be capable of meeting these high expectations. An alternative level was set which would provide relief for those monitors subjected to low emission levels. The commission believes the alternative RATA requirement of $\pm$ 2.0 ppmv from the reference method mean value is appropriate.

Dow commented on the proposed revision to §117.213(e)(1)(C) and stated that the commission should allow for a cylinder gas audit to be conducted in lieu of the annual RATA required even if the optional relative accuracy requirement of §117.213(e)(1)(B)(i) is pursued.

While the commission has allowed specific unit types under state permit to relax the RATA requirement to a cylinder gas audit, it has only done so after careful consideration. The RATA provides an independent check of the full CEMS operation, while a cylinder gas audit only assesses the monitor itself without providing an independent systems audit. The commission

believes that continuous monitors installed and operated under §117.213 should establish and demonstrate a continuing capability to meet the accuracy requirements.

GHASP supported the proposed §117.213(e)(4)(A), which specifies that all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack. Dow suggested that §117.213(E)(4)(A) be revised to specify that bypass stacks must be monitored only when in use as determined by flow indicator.

Since it is generally not possible to predict when the unit will switch from the normal operation to bypass mode or to instantaneously start operation of a CEMS from a non-functional condition, the commission believes that the only reasonable approaching to monitor emissions is by having an on-line functional CEMS on the bypass stack. This CEMS could be operated in a time-shared mode between the stack and the bypass stack, as appropriate, if the response time and measurement requirements can be met in the time-shared mode.

Dow and GHASP supported the proposed §117.213(e)(4)(B), which allows one CEMS to be shared among units.

The commission appreciates the support.

BP, Pavilion, and TCC commented on §117.213(f)(5)(A)(ii)(V) - (VI). BP and TCC expressed support for the commission's efforts to waive statistical tests that are not true indicators of the quality of the PEMS data. However, BP and TCC stated that the proposed language is too restrictive and recommended deletion of the language requiring documentation that the reference method measured concentration is less than 50% of the emission limit or standard. BP and TCC stated that many units will routinely operate above the ESADs under the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, and that the correlation analysis is meaningless, regardless of the absolute value of the emissions, if changing process conditions cannot vary the concentration. Pavilion stated that the waiver for the r-correlation test should be permanent if the data are determined to be either autocorrelated or the signal-to-noise ratio (i.e., when most of the paired observations are within the noise level of the analyzer) of the data is too low. Pavilion stated that in other words, the precision of a NO_x analyzer is only ± one or two ppm (a total of two or four ppm), and the typical standard deviation of the reference method values of 0.5 or 1.0 is less than the precision of the analyzer. Pavilion stated that for O_2, the precision of a O_2 analyzer is ± 0.25% (a total of 0.5%) and the standard deviation of the reference method values is generally about 0.088 (i.e., the process has a low signal-to-noise ratio). Pavilion stated that this situation will result in a poor r-correlation coefficient despite the attempt to vary NO_x. Pavilion further stated that if NO_x does not very significantly in comparison to the reference method data, then the r-correlation test will never be appropriate for the data, and that the proposed requirement to perform additional recertification tests will be fruitless. Pavilion recommended that the initial PEMS certification tests should be designed to ensure that the key operating parameter affecting NO_x will be moved to the limits encountered during the data gathering phase to create the PEMS. Pavilion stated that if this key parameter is moved during the initial certification test and the r-correlation test is not passed, then an analysis to determine if the data is autocorrelated or has a low signal-to-noise ratio should be conducted. Pavilion concluded that if either condition exists, then the r-correlation test should be permanently waived, with no retest, but that if not, then the PEMS has failed the r-correlation test and corrective action should be required.

The EPA included the r-correlation test as one of three required statistical tests in the 40 CFR Part 75 PEMS requirements, and the commission followed this approach by including it in the state air rules. The r-correlation test is designed to determine how well the PEMS is able to track a CEMS over time and to determine whether the PEMS is able to respond properly to changes in operating conditions. The commission has noted that while most units pass the r-correlation test, there are several that fail. Pavilion offered reasoning as to why a PEMS may fail the r-correlation test, but while autocorrelated data and/or data with low signal-to-noise ratio may be conditions of the PEMS data, the commission has not observed sufficient data to assess these issues and their association with the r-correlation failure for a PEMS. Consequently, instead of permanently waiving the test, the commission has chosen an approach to allow a temporary waiver of the requirement, but with continued collection of additional data to reassess the r-correlation.

With addition information, the commission anticipates a better assessment of the r-correlation to identify whether the test indicates the inability of the PEMS to properly correlate and track with reference method data, whether it fails in certain instances and is an inappropriate statistical test, or whether there are certain and/or specific instances or conditions whereby it is an unreliable statistic for proper monitor performance. A permanent waiver of the r-correlation prevents collection of additional information to address this statistical test issue.

BP and TCC stated that the waiver of the correlation analysis should be permanent. BP and TCC stated that the requirement to retest for the correlation analysis if emissions increase by more than 30% during a subsequent reference method test ignores the effect of ambient conditions (i.e., temperature and humidity) on emissions. BP and TCC further stated that even when the absolute level of emissions has changed, the ability of the source to vary the pollutant concentration during a subsequent test will not change. BP and TCC also stated that the commission should grant a permanent waiver of the correlation analysis when the data are shown to be autocorrelated. BP and TCC stated that a retest will almost certainly yield the same results which caused the first and subsequent failures, and that the cost of statistical testing, which TCC estimated to be $15,000 - $35,000 per fired source per test, is not justified once it has been shown that the correlation analysis is not a valid test for that source.

The commission believes that changes resulting in an increase of emissions may impact the model, and therefore believes that a repeat of the r-correlation is warranted.

Pavilion stated that if a NO_x CEMS or PEMS passes the alternative RATA requirement, then only an annual RATA test should be required, but at the higher RATA requirement of six ppmv (dry) or equivalent. By equivalent, Pavilion stated that it referred to adjusting the six ppmv (dry) requirement to a lb/MMBtu value using the average O_2 and F-Factor during the testing for boilers and furnaces or to a ppmv (dry) at 15% O_2 level for turbines using just the average O_2.

The commission does not support an alternative RATA requirement of six ppmv, since most new units are subject to NO_x emission specifications well below ten ppmv. Therefore, the commission has provided relief for units subject to low emission standards by providing an alternative relative

accuracy of ± 2.0 ppmv from the reference method value. The commission did not specify the time frame, whether six or 12 months, for the next RATA test in the proposed rule, but believes that a monitor which relies on the alternative RATA criteria based on ± 2.0 ppmv from the reference method mean value should be subject to an annual RATA frequency and provides that clarification.

Pavilion recommended that "5, 7.5, and 10 minute data averages" be allowed for the statistical tests to better correspond with the RATA test timeframe, to reduce the cost to owners (and significantly reduce the cost incurred for operating at other than optimal rates), and to allow the initial tests to be conducted in one day, also reducing costs. Pavilion stated that the RATA test takes 21 minutes per test (three seven-minute data points) and that with nine test runs, calibration takes about 4.5 hours. Pavilion stated that the corresponding statistical tests required of a PEMS currently takes a minimum of 7.5 hours (30 15-minute data points). Pavilion stated that the proposed requirements would result in a 2.5 to 5.0 hour long statistical test and the ability to complete the test in one day, and that industry will save approximately $5,000 per statistical test since the test will be able to be completed in one or two days. Pavilion further stated that the one concern with reducing the test run duration is ensuring that the PEMS and reference method data reflect the same time period. Pavilion stated that the PEMS owner and the testing firm, with assistance from the PEMS vendor, verify that the timing is correct prior to the start of each test, and therefore this concern is moot.

In 40 CFR Part 75, the EPA required a one-day period for each data set used to satisfy the statistics requirements. In the initial rule, the commission reduced this one-day time period down to periods of 15, 20, or 60 minutes each and requires 30 periods per test condition and three test conditions. The commission believes any periods of less than 15 minutes may be too short to provide valid meaningful comparative data for the PEMS statistical tests.

GHASP supported the proposed ammonia monitoring requirements for units in HGA which inject urea or ammonia into the exhaust stream for NO_x control. TCC stated that ammonia analyzer technology is unreliable and difficult to maintain, while Pavilion stated that ammonia monitoring is not proven technology and should not be required. Pavilion stated that EPA has only a conditional test method for ammonia, no ammonia monitoring performance specification test requirements, no ammonia monitoring RATA requirements, and no ongoing ammonia quality assurance/quality control (QA/QC) requirements. Pavilion further stated that no portable ammonia CEM-type test method is available for determining ammonia emissions. As an alternative, Pavilion suggested that an ammonia test be required at least annually in conjunction with the annual CEMS or PEMS RATA test. Reliant likewise suggested that annual stack testing be listed as an acceptable method to demonstrate compliance with the ammonia emission limit and stated that this method is currently accepted practice for units with SCR in several states. TCC commented on the availability of other methods to monitor ammonia emissions in §117.114(a)(4)(C) and §117.214(a)(1)(D)(iii) and stated that the commission should provide alternatives to continuous ammonia monitoring. TCC suggested consideration of EPA-approved methods or a program based on periodic Draeger tube analysis plus annual stack compliance testing, and stated that similar Draeger tube sampling is used in NO_x RACT reference method testing. Dow suggested modifying the ammonia slip limit of §117.206(e)(2)(A) to include an alternative to continuous emission monitoring for ammonia as follows: "Each stationary source which is not equipped with a continuous emissions monitoring system or predictive emissions monitoring system for ammonia shall be checked for proper operation at least monthly by stain tube. Stain tube indicators specifically designed to measure ammonia shall be acceptable provided that three sets of concentration measurements are made and averaged."

Sections 117.114(a)(4) and 117.214(a)(1)(D) provide the availability of a variety of methods to monitor ammonia emissions. The need to minimize ammonia increases will occur when the emissions start, which will be over the next several years. EPA may never promulgate an ammonia monitoring performance specification test. The commission believes that ammonia monitoring technology is available to implement continuous monitoring. True understanding of the NO_x control and resultant emissions can only come from a continuous monitor approach, and therefore, an annual test as suggested by Pavilion and Reliant is not appropriate. However, to address the technical concerns about ammonia monitoring, the commission has revised §117.114(a)(4) and §117.214(a)(1)(D) to include an alternative of weekly ammonia sampling using stain tubes which ensures that the emissions are being addressed.

TCC commented on the equation to calculate ammonia emissions in §117.114(a)(4)(A) and §117.214(a)(1)(D)(i) by material balance and stated that variable d, the correction factor, is in the wrong place in the equation. TCC stated that the equation should be revised to read: ammonia parts per million by volume (ppmv) at reference oxygen = $(a/b)(10^6) - (c)(d)$. TCC stated that this will directly adjust the amount of NO_x reduced to account for the NO/NO_2 ratio of that source.

The commission agrees and has revised the equation in §117.114(a)(4)(A) and §117.214(a)(1)(D)(i) accordingly.

TCC commented that the rule proposal preamble stated that this mass balance method uses "process parameters routinely monitored in SCR systems." TCC stated that inlet NO_x analyzers are not typically installed in single fuel systems and therefore would be an additional expense, and that the commission should allow a calculated inlet NO_x value. Reliant expressed concern about difficulties in accurately measuring or calculating flue gas flow in multiple parallel ducts, especially in large, multiple-duct EGFs. Reliant stated that the mass balance method is appropriate for installation on new gas turbines on which ducts are relatively small, where compliance-type monitors can be installed and maintained at the SCR inlets, operating levels are relatively constant, and flow is well developed. Reliant further stated that many existing units have inlet NO_x monitors installed as process control devices, not for emission compliance purposes, and that existing process control inlet NO_x monitors may not be suitable for compliance monitoring because some cannot be calibrated. Reliant recommended that annual stack testing not be used as a calibration method for a compliance method which it believed may only be suitable for limited applications. Reliant also commented on §117.114(a)(4)(B) and §117.214(a)(1)(D)(ii), which establish a method for determining ammonia emissions through oxidation of ammonia to NO. Reliant expressed the belief that dedicated equipment is needed to effectively address ammonia measurements, and that implementation of this method would require the purchase of an additional analyzer, ammonia converter, and sample line equipment for each affected unit.

There are multiple options for ammonia monitoring. Reliant's opinion is shared by some, but not all, vendors. The rule provides other options, including the option of weekly ammonia sampling. This option allows the utilities to evaluate the continuous monitoring options more fully.

MISCELLANEOUS RULE LANGUAGE COMMENTS
The commission made several minor changes for which no comments were received. Specifically, it has come to the commission's attention that the title of the division, Utility Electric Generation in East and Central Texas, is missing in the relettered §117.131(a) and in §117.141(b). The commission has corrected these omissions. The commission also replaced the phrase "pursuant to" in §117.105(k)(1) with "in accordance with" for consistency with the agency's style guidelines. In addition, the commission revised the totalizing fuel flow meter and recordkeeping requirements of §117.479(a)(1) and (g) to include references to §117.473(b). These revisions are necessary for the owner or operator of boilers and process heaters claimed exempt under §117.473(b) to be able to demonstrate compliance with the annual heat input limits.

GHASP expressed general support for various proposed changes that improve technical accuracy, eliminate loopholes.

The commission appreciates the support.

GHASP, Kaneka, and TxOGA supported the proposed changes to the "prohibition of circumvention" language in §117.206(h)(3). Kaneka stated that the revised language will allow the regulated community the flexibility to redirect chemical-bound nitrogen gas streams to non-ESAD pollution control devices. Kaneka stated that the environment will not suffer because NO_x allowances will be deducted equally for NO_x emissions from the non-ESAD pollution control devices.

The commission appreciates the support.

TIP commented on §117.206(h)(3), which is meant to prevent the shifting of emissions from units with ESADs to non-ESAD units, and expressed concern that the language is too broadly worded. TIP stated that the language, as proposed, would apply to any emission increases at non-ESAD units that are in any way connected to a change at an ESAD unit. TIP gave the example of an increase in production at an ESAD unit which results in more waste gas being sent to a flare (a non-ESAD unit) and stated that the proposed language would require that allowances to the ESAD unit be reduced. TIP suggested language which would narrow this requirement to situations in which emissions are actually redirected to a non-ESAD unit.

The commission has not revised the rules in response to this comment. The commission does not intend to cap emissions on non-ESAD units. The intent of §117.206(h)(3) is to prevent the shifting of emissions from units subject to an ESAD to non-ESAD units for the purpose of generating a reduction and creating excess allowance under the mass emissions cap and trade program. For example, a boiler subject to the cap and trade program is fueled by natural gas and a waste stream. After December 31, 2000, the waste stream is routed to a flare and the boiler is then fueled only by natural gas. Due to the cleaner fuel burned by the boiler, its NO_x emissions decrease. Conversely, the NO_x emissions from the flare increase due solely to the increase in throughput from flaring the waste stream. In this scenario, allowances would be deducted from the boiler's allocation equivalent to the direct NO_x increase at the flare.

GHASP supported the proposed new §117.206(h)(4) and §117.475(g) which specify that a source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of Chapter 117. Dow suggested that sources which are derated through enforceable limits to emissions less than 25 tpy should not be classified as major sources.

The commission disagrees with Dow. The proposed new §117.206(h)(4) and §117.475(g) are necessary to close a potential loophole for certain major sources. Currently, if a major source in HGA consists primarily of units which are not subject to an ESAD, includes one or more units for which an ESAD has been established, but is not subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, because the cumulative design capacity to emit of the units subject to ESADs is less than ten tpy, it could be interpreted that this major NO_x emission source would not be required to make any emission reductions. It was never the commission's intention to exempt major NO_x emission sources which have a limited amount of affected units from reducing NO_x emissions. The change will ensure that such sources are subject to the same ESADs and the same emission reduction requirements as other major sources.

Shrader stated that operating a diesel engine without it being under load increases the NO_x emissions and also shortens the engine life by about 50%. Shrader suggested that §117.206(i) and §117.478(c) specify that engine operation for maintenance must be done under load.

NO_x formation is primarily dependent on the temperature at which combustion occurs in the engine, with lower temperatures resulting in less NO_x formation. Consequently, diesel engine manufacturers have moved to aftercooling the intake air. With an unloaded engine, the combustion temperatures will be lower and the NO_x formation also lower. While the brake-specific NO_x (grams of NO_x produced per hour divided by the engine output in brake horsepower) may be higher when operating in an unloaded condition due to the much lower output of the engine, the engine's total NO_x output (grams per hour) will be lower than in a loaded condition.

Diesel engines have fuel injection in the form of injectors that meter in a specified amount of fuel into the cylinder based on the engine load. A governor strives to keep the engine at constant speed (revolutions per minute (RPM)) under all loads. As the load increases, more fuel is required to keep the engine at constant speed due to the counter-electromotive force of the generator (counter-torque put on the engine by the generator). As a result, at low loads very little fuel is needed to keep the engine speed constant. Less combustive energy, and thus lower combustion temperatures, result from low fuel rates at low load, and therefore total NO_x formation is reduced. Diesel engine manufacturers do not endorse the operation of engines with no load as this can cause maintenance issues and shorter engine life. There is no rule-of-thumb that quantifies the life expectancy reduction for an engine that is operated unloaded. However, the potential for reduced engine life provides strong motivation for an owner or operator to perform each operation of a diesel engine for maintenance in a loaded condition. The commission made no change in response to the comment.

Shrader suggested that low-sulfur diesel fuel be required for stationary diesel back-up generators.

The requirements of 30 TAC Chapter 114, Subchapter H, Division 2, concerning Low Emission Diesel, include low-sulfur diesel fuel for motor vehicles and non-road equipment in 95 attainment counties in the eastern half of Texas as well as in the BPA, DFW, and HGA ozone nonattainment areas. Stationary diesel engines meet the definition of non-road equipment as defined in 30 TAC §114.6, concerning Low Emission Fuel Definitions, and therefore the fuels used in these engines are subject to the low-sulfur diesel requirements of 30 TAC Chapter 114, Subchapter H, Division 2.

Shrader suggested specifying EPA, or California Air Resources Board (CARB), or both for compliance to meet the stationary diesel engine testing requirements for stationary diesel back-up generators.

There are no CARB emission standards that apply to stationary diesel engines in Texas. However, stationary diesel engines claimed exempt under §117.203(a)(12) or §117.473(a)(2)(I) are required to meet the EPA non-road engine standards listed in 40 CFR §89.112(a), Table 1. Detailed information about these standards can be found at: http://www.epa.gov/fedrgstr/EPA-AIR/1998/October/Day-23/a24836.htm and http://www.access.gpo.gov/nara/cfr/waisidx_01/40cfr89_01.html. The Chapter 117 testing requirements are given in §117.214(b) and §117.479(e).

Shrader stated that because the EPA has established the non-road diesel engine standards based on engine horsepower produced by the engine, and year of manufacture, it will be important for field investigators to be able to identify this information. Shrader suggested the posting of emission certificates adjacent to engines or, if installed outside, within engine enclosures for stationary diesel engines. Shrader stated that these certificates can be obtained from the manufacturer, and that the engine series number, serial number, year of manufacture, compliance codes, EPA tier number rating, etc. could be easily added to the certificate, and the paper certificate could be laminated to protection it. Shrader stated that these certificates should be tied back to the permanent identification stampings on the engines to prevent counterfeiting.

No changes were proposed to the stationary diesel engine recordkeeping requirements of §117.219(f)(3) and (10) or §117.479(h) and (j). However, the commission agrees that because different requirements apply depending on the horsepower rating, model year, and date of installation, modification, reconstruction, or relocation, it is important for owners and operators of stationary diesel engines to document compliance by maintaining the appropriate information, including the documentation recommended by the commenter. The commenter's suggestions would make determination of compliance easier for field investigators, and the commission encourages owners and operators to follow these suggestions. The commission may consider incorporating the commenter's suggestions in future rulemaking.

GHASP supported the proposed §117.207(j), while BP and TCC stated that "a unit" should be changed to "units" to clarify that when the total allocation under the HGA mass emissions cap becomes less than the total allocation under the plant-wide emission specifications, the entire plant-wide emission specifications no longer apply.

The commission agrees with BP and TCC and made the suggested revision to §117.207(j). In addition, the commission made corresponding clarifications in §117.107(e) and §117.223(l) and corrected "system cap" to "source cap" in §117.223(l).

No comments were received on the proposed revisions to §117.321 and §117.421. However, it has come to the commission's attention that the references to §50.39 should be deleted because this section only applies to any application that is declared administratively complete before September 1, 1999. The references to §50.139, which applies to any application that is declared administratively complete on or after September 1, 1999, are appropriate and have been retained. In addition, the commission has replaced the reference to an appeal to the commission with a reference to filing a motion to overturn the executive director's decision. Finally, the commission has deleted redundant references to written notification.

SYSTEM CAP

Sierra-Houston opposed the proposed deletion of the intermediate compliance dates in the system cap compliance schedule for non-utility EGFs in §117.520(c)(2)(B)(iii), while GHASP supported the proposed revision to §117.520(c)(2)(B)(iii). GHASP agreed that this may be an unnecessarily complicated schedule and agreed that the commission should endeavor to allow the affected industries more options for planning and implementing incremental reductions in emissions. GHASP agreed that the proposed revision to §117.520(c)(2)(B)(iii) would not affect the March 31, 2007 final compliance date nor would it increase final emission rates, and would still achieve the final emission reductions as required by the SIP, while Sierra-Houston believed that the proposed revision would delay emission reductions. GHASP requested that the commission estimate whether the deletion of intermediate compliance dates could lead to a significant increase in NO_x emissions that would otherwise occur in the intermediate years, where significant refers to a level of additional NO_x emissions that the commission has determined may be significant in affecting the number of days on which ozone levels could be expected to exceed federal standards. GHASP stated that if the commission finds that such a significant increase could occur, it recommended that the commission simplify the schedule but retain at least one intermediate compliance date.

The same SIP reductions will still occur on the phased-in schedule established in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3. However, the revision will give the regulated community the flexibility to broadly choose which units are controlled to meet the applicable stepdown in allowances each year, rather than being mandated to make EGF reductions on a specific schedule.

EXEMPTIONS

NASA commented that §117.203(a)(6)(D) exempts engines that are operated exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a 12-month average. NASA noted that the definition of emergency situation in §117.10 excludes operation for training purposes or other foreseeable events and expressed concern that §117.203(a)(6)(D) allow operation for training purposes.

As NASA noted, §117.203(a)(6)(D) provides an exemption for engines that are operated exclusively in emergency situations, with operation for testing or maintenance purposes allowed

up to 52 hours per year, based on a 12-month average. The appropriate exemption for engines placed into service before October 1, 2001 which operate minimally, but not exclusively in emergency situations, is found in §117.203(a)(11). This exemption limits operation to less than 100 hours per year, based on a 12-month average, and would allow for some, albeit limited, operation for foreseeable events such as training.

As described earlier in this preamble, the existing definition of emergency situation was, as the term implies, developed to define emergency situations. It was not intended to include scheduled outages, or operation for training, testing, or maintenance purposes. If a blanket exclusion for these activities were allowed, then extensive operation of high-emitting diesel engines could occur, and the resulting emissions would not be limited in any meaningful way. The commission's intention is that engines with more than de minimis operations do not qualify for one of the exemptions under §117.203(a)(6), (11), or (12), but instead would be subject to the ESADs under §117.206(c)(9)(D) in conjunction with the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3.

Dow and GHASP supported the new §117.206(i)(3) and §117.478(c)(3), which add seasonal exclusions for emergency response training diesel firewater pumps from the engine testing or maintenance time-of-day operating restrictions.

The commission appreciates the support.

COMPLIANCE SCHEDULE
AECT and TXU supported the proposed revisions to §117.512(a)(A) which address the initial compliance year period.

The commission appreciates the support.

AECT, CPS, and TXU commented on the compliance schedule for the proposed CO limit for electric utilities in east and central Texas. AECT and TXU stated that the NO_x limits for electric utilities in east and central Texas became effective on May 5, 2000, with a compliance date of May 1, 2003, and that companies subject to these limits are currently installing combustion controls designed to achieve the required NO_x reductions. AECT and TXU stated that based on the analysis of currently available monitoring data, the 400 ppmv CO limit is generally achievable (with 24-hour averaging) for all gas-fired units in east and central Texas. TXU commented that it has demonstrated its ability to achieve this limit for its gas-fired units in DFW. AECT and TXU stated that similar monitoring data for NO_x and CO emissions on coal-fired units show varying CO emission rates, and that adding a CO limit with a May 1, 2003 compliance date will not allow enough time for coal-fired units to comply.

While EGFs owned by electric utilities which are subject to the cost-recovery provisions of TUC, §39.263(b), have a compliance date of May 1, 2003, other units have a compliance date of May 1, 2005. Nevertheless, the commenters are correct that the initial compliance date for some units is May 1, 2003. Because the commission has deleted the CO limit, the commenters' concerns are moot. However, in order to allow sufficient time for EGFs to comply with the ammonia limits (or, if needed, pursue an alternative case-specific ammonia emission limit under §115.151), the

commission has added a new §117.512(1)(C) to establish a May 1, 2005 compliance date for electric utilities in east and central Texas to meet the ammonia limit of §117.135(2).

Reliant stated that more time is needed to install and to operate continuous ammonia emissions measurement systems upon completion of flue gas cleanup retrofits because ammonia monitoring is a less-established monitoring technology. Reliant recommended that the monitoring deadline provisions in §117.510(c)(2)(A)(i) and §117.520(c)(2)(A)(i) should not apply to the installation of ammonia monitors, but that instead these rules should be revised to allow regulated facilities to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until at least March 31, 2005.

The commission agrees and has revised §§117.510(c)(2)(A)(i), 117.520(c)(2)(A)(i), and 117.534(1)(A) and (2)(A) accordingly.

No comments were received on §117.520(c)(2)(A)(ii), which specifies that the owner or operator must submit the results of either a stack test or the CEMS or PEMS performance evaluation and quality assurance procedures within 60 days after startup of a unit following installation of NO_x controls. The intent in §117.520(c)(2)(A)(i) is that a unit which is controlled with flue gas clean-up (e.g., SCR) must have its CEMS or PEMS certified within 60 days after startup of the unit with flue gas clean-up. For units with combustion modifications only, made before March 31, 2005, the intent is that the CEMS or PEMS installation could be deferred until March 31, 2005, although the performance evaluation and quality assurance procedures still must be submitted by that date. It has come to the commission's attention that the reference to §117.211 in §117.520(c)(2)(A)(ii)(I) would require the CEMS or PEMS to be operational before stack testing, due to the requirements of §117.211(c). Because this is not what the commission intended for units in HGA for which CEMS or PEMS installation is deferred until March 31, 2005, the commission has revised §117.520(c)(2)(A)(ii)(I) to clarify the commission's intent and eliminate the inconsistency described in the previous sentence. In addition, the commission has revised §117.520(c)(2)(A)(ii)(II) to clarify that if the monitoring system installation is deferred until March 31, 2005, the performance evaluation and quality assurance procedures still must be submitted by that date. The commission has made corresponding revisions to §117.534(1)(B)(i) and (2)(B)(i) to clarify the commission's intent that the requirement in §117.479(e)(6) for CEMS or PEMS to be operational before stack testing does not apply to a stack test conducted before March 31, 2005 on a unit not equipped with CEMS or PEMS for which CEMS or PEMS must be installed no later than March 31, 2005. In addition, the commission has made corresponding revisions to §117.534(1)(B)(ii) and (2)(B)(ii) to clarify that if the monitoring system installation is deferred until March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures still must be submitted by that date.

Dow commented on the revision to the system cap compliance schedule for non-utility EGFs in §117.520(c)(2)(B)(iii) which would delete the intermediate compliance dates and stated that the current §117.520(c)(2)(B)(iii)(I) - (IV) still appeared to be in the proposed revisions to §117.520(c)(2)(B)(iii).

The current §117.520(c)(2)(B)(iii)(I) - (IV) appears in the proposal but is bracketed to indicate that this language is proposed for deletion.

GHASP commented on §117.520(c)(2)(B)(iii) and agreed that this schedule may be unnecessarily complicated and that the commission should allow the affected industries more options for planning and implementing incremental reductions in emissions. GHASP agreed that the proposed amendment would not affect the March 31, 2007 final compliance date nor would it increase final emission rates, and would still achieve the final emission reductions as required by the SIP.

Although the schedule may have been complicated, the revisions give the regulated community the flexibility to broadly choose which units are controlled to meet the stepdown in allowances each year, rather than being mandated to make reductions on a specific schedule.

GHASP requested that the commission also estimate whether the deletion of intermediate compliance dates in §117.520(c)(2)(B)(iii) could lead to a significant increase in NO_x emissions that would otherwise occur in the intermediate years, where significant refers to a level of additional NO_x emissions that the commission has determined may be significant in affecting the number of days on which ozone levels could be expected to exceed federal standards. GHASP recommended that if the commission finds that such a significant increase could occur, the schedule should be simplified but retain at least one intermediate compliance date.

There is no reason to believe that additional NO_x emissions would occur upon deletion of the intermediate compliance dates in §117.520(c)(2)(B)(iii) because, as currently written, these intermediate compliance dates are not expected to result in reductions beyond those that will occur regardless, due to the reduction in allowances under the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3. In other words, the same SIP reductions will still occur on the phased-in schedule established in the mass emissions cap and trade program. However, the revision will give the regulated community the flexibility to broadly choose which units are controlled to meet the stepdown in allowances each year, rather than being mandated to make EGF reductions on a specific schedule.

AES stated that it has only a single unit which is subject to the HGA ESADs, and therefore the phased-in NO_x reductions required by the SIP do not provide AES much opportunity to investigate emerging NO_x control technologies, particularly compared to sites with multiple units subject to the ESADs.

A major source with a single unit, or a small number of units, does not necessarily have to install controls to achieve all of the target emission reductions by the first compliance date. The owner or operator of each affected source is free to choose the control technology which best addresses the circumstances of the affected sources, obtain additional allowances from another facility's surplus allowances, or a combination of the two approaches. The owner or operator might choose to make Tier I combustion modifications sufficient to achieve the initial rate-of-progress reductions in order to delay the capital expenditure for Tier II controls until a later date. Alternatively, the owner or operator might choose to implement the emission reduction projects ahead of schedule in order to be able to sell the surplus allowances. There is an infinite number of permutations. Ultimately, each owner or operator will make a business decision believed to represent the best choice for each unique situation. The compliance schedule requires the final reductions by March 31, 2007, which will allow additional incorporation of emerging technologies, reduce labor and material availability concerns, and concurrently reduce costs.

COST

Greater Houston Partnership stated that "a previous study by the Universities of Houston and Chicago concluded that this last increment (10%) of NO_x controls {i.e., the difference between the ESADs as adopted on December 6, 2000 and the BCCA-AG's alternate ESADs} has significant negative impacts on the region's economy." BCCA-AG and Lyondell stated that implementation of the alternate ESADs will require several billion of dollars in new and retrofit combustion and post-combustion controls, and that these controls will place a significant burden on Houston's economy, as increasingly scarce capital and operating expenses will be devoted to NO_x controls rather than to job-creating new manufacturing technologies and productivity improvements. BCCA-AG and Lyondell asserted that the current ESADs are not economically reasonable for many sources and, on the whole, will have the effect of significantly retarding economic *growth* in HGA. (Emphasis added.) BCCA-AG and Lyondell asserted that their position is supported by the BCCA's September 25, 2000 comments filed by BCCA and other commenters and the testimony of Smith, Deason, and McAngus in the temporary injunction hearing held before Judge Margaret Cooper, Travis County District Court, Texas, on May 14 - 18, 2001. BCCA-AG and Lyondell referenced the January 2001 version of *Cleaning Up Houston's Act: An Economic Evaluation of Alternative Strategies*. BCCA-AG and Lyondell stated that the adoption of the alternate ESADs will significantly lessen the adverse economic impact of the NO_x point source rules and that by 2010, these proposed rule changes will help reduce the economic burden of the SIP by over $2 billion annually, preserve $850 million annually in tax revenue and save 65,000 jobs.

It appears that Greater Houston Partnership is referring to an economic analysis report, *Cleaning Up Houston's Act: An Economic Evaluation of Alternative Strategies* (December 2000) and/or a January 2001 updated version of this report, both of which were commissioned by BCCA and authored by Dr. Barton Smith (Smith) and Dr. George Tolley (Tolley). The commission's detailed discussion of the numerous flaws in the Smith/Tolley study is found in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8150). Notably, according to an article in the Houston Chronicle on May 2, 2002, Smith said that Houston's economic growth will be more robust than those of the United States or Texas beginning after mid-2003, which directly contradicts his sworn testimony in the May 2001 temporary injunction hearing in which he stated that one of the most significant impacts of the attainment demonstration SIP on the Houston economy will be the inability of the petrochemical and refining industries to grow. The commission further notes that the time period for which Smith predicts that Houston's economic growth will be more robust than those of the United States or Texas (i.e., after mid-2003) occurs shortly after the NO_x reductions required of electric utilities on April 1, 2003 and coincides with the period immediately preceding the next round of reductions, when electric utilities and non-utility sources will be in the midst of implementing numerous control projects to achieve the NO_x reductions required on April 1, 2004.

The commission notes that BCCA-AG and Lyondell both expect continued economic growth in HGA, even with the implementation of the current ESADs. In addition, BCCA-AG and Lyondell did not present information to document their claim that implementation of the alternate ESADs and HRVOC rules will save "$2 billion annually, preserve $850 million annually in tax revenue and save 65,000 jobs." However, the commission notes that BCCA-AG is a subset of BCCA, which in turn is a subset of the Greater Houston Partnership. The commission further notes that in Greater Houston Partnership's application to the Texas General Land Office for Coastal Impact Assistance Program funding for the "Ozone Science and Modeling Research Project" to

"more accurately calibrate the ozone air model" in HGA (available at http://www.glo.state.tx.us/coastal/ciap/pdf/state/OzoneScience-checklist.pdf), Greater Houston Partnership stated that the current HGA SIP "would cost the region $13 billion and would curtail growth in key economic sectors." Greater Houston Partnership also stated in this application that "more accurate controls developed using a recalibrated model for the HGA will reduce the economic burden to the region by $9.15 billion and, in the process, create additional annual tax revenues of $521 million and significantly reduce expected job loss in the region." However, in its September 25, 2000 written comments on the proposed HGA SIP, BCCA estimated the entire cost for the then-proposed ESADs to be $5 to $6 billion. Although BCCA stated that this estimate did not include "extraordinary costs such a plot spacing limitations, new infrastructure, or significant combustion unit rebuilding," it is interesting to note that Greater Houston Partnership's claims of cost savings from the difference between implementation of the ESADs and the alternate ESADs appear to be greater than the cost estimated by its subgroup, BCCA, for implementation of the December 2000 ESADs in their entirety.

AECT and TXU commented on the statement in the rule proposal preamble that "there are no costs associated with the proposed new CO emission limits" for EGFs in east and central Texas because "the commission expects that the units are already meeting the proposed limits or, if retrofitted with NO_x controls in the future, will be able to meet the proposed limits without additional modifications." AECT and TXU stated that most coal-fired units are not currently meeting the proposed CO limit, whether before or after the NO_x modifications. TXU stated that the boiler manufacturer for its lone wall-fired coal boiler estimates that it will cost $10 million in equipment and construction costs (excluding replacement power costs during construction) to re-engineer the boiler to potentially achieve the required NO_x limit while also meeting the proposed CO limit. AECT and TXU stated that while they do not have cost estimates for other units, they expect costs similar costs to the $10 million estimate. TXU further stated that for its eight tangentially-fired coal boilers, new fans, fan motors, electrical switch gear, auxiliary transformers, fuel piping and burner modifications, and other modifications, may be required to meet the proposed CO limit and that these modifications are expected to cost in the range of $10 to $20 million for each boiler.

TXU and AECT did not submit documentation of their cost estimates. The intent of the proposed CO limit is to implement best engineering practices toward the minimization of CO, not expensive capital items such as new fans. Boiler tuning, or measures which offer paybacks in efficiency, such as neural network control, would be the options which would have to implemented before the alternative emission limit would be granted. Because the commission has deleted the CO limit, as described earlier in this preamble, there will be no compliance costs.

CPS stated that there is currently only a one-time CO testing requirement for EGFs in east and central Texas, and stated that as a result CPS will incur significant costs from installing and operating CO monitors at its 13 affected units and/or conducting stack testing once a year and sampling for CO regularly.

As noted earlier in this preamble, the proposed §117.143(b)(2)(A) specifies that CO sampling is to be conducted whenever either of the following occur: 1) NO_x emissions are sampled with a portable analyzer; or 2) NO_x emissions measured by CEMS or predicted by PEMS are lower than

levels for which CO emissions data was previously gathered. Therefore, CO tests would only be required when NO_x tests are being done anyway. Because the commission revised §117.143(b)(2)(A) such that CO monitoring is no longer required, there will be no compliance costs.

Louisiana-Pacific stated that the economic viability of its Cleveland plywood manufacturing and sawmill complex is threatened by both the existing wood-fired boiler ESAD in §117.206(c)(5) of 0.046 lb NO_x/MMBtu and the proposed revision of this ESAD to 0.060 lb NO_x/MMBtu. Louisiana-Pacific reviewed possible controls for its wood-fired boiler and estimated that the highest cost, that of SCR, would include an initial capital cost of $6 million (including an ESP), an annual operating cost of about $1.1 million, and a cost-effectiveness of $11,300 per ton of NO_x removed.

The maximum estimated cost per ton of NO_x removed which Louisiana-Pacific reported is less than that estimated by the commission for other categories of equipment in HGA. Other SIP revisions for ozone nonattainment areas have included control measures with costs over $10,000 per ton. One company's costs to comply with a SIP rule in DFW were reported to be around $33,000 per ton while the company was in Chapter 11 bankruptcy. In summary, the cost per ton of NO_x removed which Louisiana-Pacific estimated is similar to or less than that of other HGA sources.

In addition, the commission has included flexibility to the extent possible while still achieving the emission reduction goals. Specifically, under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs.

Louisiana-Pacific commented that if the proposed revision of the existing wood-fired boiler ESAD in §117.206(c)(5) from 0.046 lb NO_x/MMBtu to 0.060 lb NO_x/MMBtu is adopted and the company is compelled at some future time to close its Cleveland plywood manufacturing and sawmill complex, the "combined economic, health and welfare effects of the plant closure would outweigh" the effects of the emission reductions on ozone levels in HGA.

TCAA, §382.011, requires the commission to establish the level of quality to be maintained in the state's air and to control the quality of the state's air. The commission is required to "seek to accomplish" this through the control of air contaminants by "practical and economically feasible methods." The level of quality of the state's air is measured by whether the air complies with the NAAQS. According to 42 USC, §7409(b), national primary ambient air quality standards are standards which, in the judgment of the administrator of the EPA, are requisite to protect the public health. The criteria for setting the standard is protection of public health, which includes an allowance for an adequate margin of safety. The ESADs were developed in order for HGA to achieve attainment with the ozone NAAQS, which is a health-based standard and not a cost-based standard.

Louisiana-Pacific did not provide detailed revenue and cost information demonstrating, even with the use of the mass emissions cap and trade program, that the choices to comply through the use of retrofits, replacement and consolidation, and/or shutdown of existing equipment will cause the rules to be economically infeasible. If cost analyses are conducted and production lines are shut down on a limited scale, it could be viewed as the most rational solution to obtaining the goals of a cleaner environment and maintaining an efficient marketplace.

It should also be noted that the commission proposed to revise the existing wood-fired boiler ESAD in §117.206(c)(5) to a less-stringent level. Thus, the proposed revision can only have a positive economic effect on the company's Cleveland plywood manufacturing and sawmill complex because it will be required to make fewer NO_x emission reductions.

AES stated that compared to the use of SCR on similar coal-fired units, the capital costs of SCR systems applied to its coke-fired unit will be over 50% greater, and that annual costs (excluding annualized capital costs) will be 67% greater in its coke-fired unit.

In the rule proposal preamble for the original HGA ESADs which was published in the August 25, 2000, issue of the *Texas Register* (25 TexReg 8275), the commission estimated the following costs for various categories of equipment in terms of dollars per ton of NO_x reduced: 1,000 - 8,000, 4,500, 10,000, 4,000, 728, 2,525, 2,900, 3,800, 1,800, 2,000 - 4,500, 1,141, 2,705, 4,800, 3,000, 2,510, 5,700, 4,700, 4,800, 50 - 25,000, 1,000, 2,500, and 13,000 - 75,000. The estimated cost for controlling emissions from the AES coke-fired boiler was $728 per ton of NO_x reduced, or far less than every other equipment category except the low end of the range given for the stationary internal combustion engine category. Assuming that AES's estimate of higher SCR costs for controlling a coke-fired boiler (as compared to a coal-fired boiler) is accurate, the estimated cost for controlling emissions from the AES coke-fired boiler would be on the order of only $1,250 per ton of NO_x reduced, or still far less expensive than nearly all other categories of equipment in terms of dollars per ton of NO_x reduced. This result is not unexpected, given that AES

Deepwater's coke-fired boiler is the sixth-largest stationary NO_x point source in the 1997 EI for HGA, exceeded only by one gas-fired utility boiler and four coal-fired utility boilers. Simply put, there is economy of scale which lowers the cost (in terms of dollars per ton of NO_x reduced) for units with higher uncontrolled emissions because more emissions are being controlled for each dollar spent to reduce emissions.

TXI stated that SCR and SNCR are "economically unreasonable for a small operation" like its Clodine LWA plant. TXI also stated that low temperature oxidation technology for NO_x control has an operating cost that is proportional to the amount of NO_x abated. TXI estimated that the operating cost would be approximately $6,000 per ton, or an annual operating cost of approximately $800,000, which TXI asserted is prohibitive for an operation the size of its LWA plant. TXI stated that it estimates the capital cost to be almost $2,500 per ton on a $.12 per year capital recovery basis, not including additional costs such as interconnection of the system to the existing duct systems; concrete foundations and structure for housing the ozone generator; electrical connections; oxygen-clean piping from the oxygen supply to the ozone generator, and from the ozone generator to the injection point; power and cooling water system makeup; oxygen storage and supply; and operation and maintenance of the NO_x reduction system.

The estimated cost per ton of NO_x removed which TXI reported is less than that estimated by the commission for several other categories of equipment in HGA, as described in the response to the previous comment. Other SIP revisions for ozone nonattainment areas have included control measures with costs over $10,000 per ton. One company's costs to comply with a SIP rule in DFW were reported to be around $33,000 per ton while the company was in Chapter 11 bankruptcy. In summary, the cost per ton of NO_x removed which TXI estimated is similar to or less than that of other HGA sources. According to the low-temperature oxidation vendor, their oxidation scrubbing cost estimates range from $1,500 - $2,500 per ton, although some owners have estimated $8,000 - $10,000 per ton. Cost evaluations from one chemical plant are running at $8,000 - $10,000 per ton for SIP compliance. Many sources are expected to have costs in this range.

In addition, the commission has included flexibility to the extent possible while still achieving the emission reduction goals. Specifically, under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs.

Because full-scale commercial applications of low-temperature oxidation have demonstrated NO_x removal efficiencies on the order of 90%, well in excess of the 30% reductions envisioned by the LWA ESAD originally proposed in August 2000, TXI is in a unique position to benefit from market-based compliance. Because the reduction required of LWA kilns is much less than the 80% - 90% range required of other sources, TXI is in a position to monetize overcompliance. Low-temperature oxidation technology is particularly amenable to responding to market-based demand for NO_x allowances. If allowance prices are low, operating costs are lowered by reducing scrubber operation to produce only the reductions needed to stay below the allocation; if prices are high, the low marginal cost of additional control compared to the allowance value means that surplus allowances can be marketed at a profit. Market-based compliance through the mass emissions cap and trade program allows flexibility on timing of installation of a control system. Installation of a control system can be deferred with allowance purchases used to cover early reduction obligations. Market trading also allows risk reduction through use of "put options" and "call options." "Put options" give the buyer the right, but not the obligation, to sell an asset (in this case, NO_x allowances) at a specific price for a fixed amount of time. "Call options" give the buyer the right, but not the obligation, to purchase an asset (again, NO_x allowances) at a specific price for a fixed amount of time.

SUBCHAPTER A: DEFINITIONS
§117.10

STATUTORY AUTHORITY
The amendment is adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which authorizes the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendment is also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§117.10. Definitions.

Unless specifically defined in the Texas Clean Air Act or Chapter 101 of this title (relating to General Air Quality Rules), the terms in this chapter shall have the meanings commonly used in the field of air pollution control. Additionally, the following meanings apply, unless the context clearly indicates otherwise. Additional definitions for terms used in this chapter are found in §101.1 and §3.2 of this title (relating to Definitions).

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

(2) **Applicable ozone nonattainment area** - The following areas, as designated under the 1990 Federal Clean Air Act Amendments.

(A) Beaumont/Port Arthur (BPA) ozone nonattainment area - An area consisting of Hardin, Jefferson, and Orange Counties.

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

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

(3) **Auxiliary steam boiler** - Any combustion equipment within an electric power generating system, as defined in this section, that is used to produce steam for purposes other than generating electricity. An auxiliary steam boiler produces steam as a replacement for steam produced by another piece of equipment which is not operating due to planned or unplanned maintenance.

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

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

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

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

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

(9) **Continuous emissions monitoring system (CEMS)** - The total equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates in units of the applicable emission limitation.

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

(11) **Diesel engine** - A compression-ignited two- or four-stroke engine in which liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition.

(12) **Duct burner** - A unit that combusts fuel and that is placed in the exhaust duct from another unit (such as a stationary gas turbine, stationary internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases.

(13) **Electric generating facility (EGF)** - A unit that generates electric energy for compensation and is owned or operated by a person doing business in this state, including a municipal corporation, electric cooperative, or river authority.

(14) **Electric power generating system** - One electric power generating system consists of either:

(A) for the purposes of Subchapter B, Division 1 of this chapter (relating to Utility Electric Generation in Ozone Nonattainment Areas), all boilers, auxiliary steam boilers, and stationary gas turbines (including duct burners used in turbine exhaust ducts) at electric generating facility (EGF) accounts that generate electric energy for compensation; are owned or operated by a municipality or a Public Utility Commission of Texas regulated utility, or any of its successors; and are entirely located in one of the following ozone nonattainment areas:

(i) Beaumont/Port Arthur;

(ii) Dallas/Fort Worth; or

(iii) Houston/Galveston;

(B) for the purposes of Subchapter B, Division 2 of this chapter (relating to Utility Electric Generation in East and Central Texas), all boilers, auxiliary steam boilers, and stationary gas turbines at EGF accounts that generate electric energy for compensation; are owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility, or any of its successors; and are located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County; or

(C) for the purposes of Subchapter B, Division 3 of this chapter (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas), all units in the Houston/Galveston ozone nonattainment area that generate electricity but do not meet the conditions specified in subparagraph (A) of this paragraph, including, but not limited to, cogeneration units and units owned by independent power producers.

(15) **Emergency situation** - As follows.

(A) An emergency situation is any of the following:

(i) an unforeseen electrical power failure from the serving electric power generating system;

(ii) the period of time during which an emergency notice, as defined in *ERCOT Protocols, Section 2: Definitions and Acronyms* (July 1, 2002), issued by the Electric Reliability Council of Texas, Inc. (ERCOT) as specified in *ERCOT Protocols, Section 5: Dispatch* (September 1, 2002), is applicable to the serving electric power generating system. The emergency situation is considered to end upon expiration of the emergency notice issued by ERCOT;

(iii) an unforeseen failure of on-site electrical transmission equipment (e.g., a transformer);

(iv) an unforeseen failure of natural gas service;

(v) an unforeseen flood or fire, or a life-threatening situation; or

(vi) operation of emergency generators for Federal Aviation Administration licensed airports, military airports, or manned space flight control centers for the purposes of providing power in anticipation of a power failure due to severe storm activity.

(B) An emergency situation does not include operation for purposes of supplying power for distribution to the electric grid, operation for training purposes, or other foreseeable events.

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

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

(18) **Heat treat furnace** - A furnace that is used in the manufacturing, casting, or forging of metal to heat the metal so as to produce specific physical properties in that metal.

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

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

(21) **Incinerator** - As follows.

(A) For the purposes of this chapter, the term “incinerator” includes both of the following:

(i) a control device that combusts or oxidizes gases or vapors (e.g., thermal oxidizer, catalytic oxidizer, vapor combustor); and

(ii) an incinerator as defined in §101.1 of this title (relating to Definitions).

(B) The term “incinerator” does not apply to boilers or process heaters as defined in this section, or to flares as defined in §101.1 of this title.

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

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

(24) **Large DFW system** - All boilers, auxiliary steam boilers, and stationary gas turbines that are located in the Dallas/Fort Worth ozone nonattainment area, and were part of one electric power generating system on January 1, 2000, that had a combined electric generating capacity equal to or greater than 500 megawatts.

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

(26) **Low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit** - An industrial, commercial, or institutional boiler; process heater; or gas turbine supplemental waste heat recovery unit with maximum rated capacity:

(A) greater than or equal to 40 million Btu per hour (MMBtu/hr), but less than 100 MMBtu/hr and an annual heat input less than or equal to 2.8 (10^{11}) Btu per year (Btu/yr), based on a rolling 12-month average; or

(B) greater than or equal to 100 MMBtu/hr and an annual heat input less than or equal to 2.2 (10^{11}) Btu/yr, based on a rolling 12-month average.

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

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

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

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

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

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

(D) the amount specified in the major source definition contained in the Prevention of Significant Deterioration of Air Quality regulations promulgated by EPA in Title 40 Code of Federal Regulations (CFR) §52.21 as amended June 3, 1993 (effective June 3, 1994) and is located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Comal, Ellis, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Hays, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County.

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

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

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

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

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

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

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

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

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

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

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

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

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

(39) **Predictive emissions monitoring system (PEMS)** - The total equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates using process or control device operating parameter measurements and a conversion equation or computer program to produce results in units of the applicable emission limitation.

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

(41) **Pyrolysis reactor** - A unit that produces hydrocarbon products from the endothermic cracking of feedstocks such as ethane, propane, butane, and naphtha using combustion to provide indirect heating for the cracking process.

(42) **Reheat furnace** - A furnace that is used in the manufacturing, casting, or forging of metal to raise the temperature of that metal in the course of processing to a temperature suitable for hot working or shaping.

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

(44) **Small DFW system** - All boilers, auxiliary steam boilers, and stationary gas turbines that are located in the Dallas/Fort Worth ozone nonattainment area, and were part of one electric power generating system on January 1, 2000, that had a combined electric generating capacity less than 500 megawatts.

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

(46) **Stationary internal combustion engine** - A reciprocating engine that remains or will remain at a location (a single site at a building, structure, facility, or installation) for more than 12 consecutive months. Included in this definition is any engine that, by itself or in or on a piece of equipment, is portable, meaning designed to be and capable of being carried or moved from one

location to another. Indicia of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine being replaced is included in calculating the consecutive residence time period. An engine is considered stationary if it is removed from one location for a period and then returned to the same location in an attempt to circumvent the consecutive residence time requirement. Nonroad engines, as defined in 40 CFR §89.2, are not considered stationary for the purposes of this chapter.

(47) **System-wide emission limit** - The ratio of the total allowable nitrogen oxides mass emissions rate dischargeable into the atmosphere from affected units in an electric power generating system or portion thereof located within a single ozone nonattainment area when firing at their maximum rated capacity to the total maximum rated capacities for those units. For fuel oil firing, average activity levels shall be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission limit.

(48) **System-wide emission rate** - The ratio of the total actual nitrogen oxides mass emissions rate discharged into the atmosphere from affected units in an electric power generating system or portion thereof located within a single ozone nonattainment area when firing at their maximum rated capacity to the total maximum rated capacities for those units. For fuel oil firing, average activity levels shall be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission rate.

(49) **Thirty-day rolling average** - An average, calculated for each day that fuel is combusted in a unit, of all the hourly emissions data for the preceding 30 days that fuel was combusted in the unit.

(50) **Twenty-four hour rolling average** - An average, calculated for each hour that fuel is combusted (or acid is produced, for a nitric or adipic acid production unit), of all the hourly emissions data for the preceding 24 hours that fuel was combusted in the unit.

(51) **Unit** - A unit consists of either:

(A) for the purposes of §117.105 and §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology) and each requirement of this chapter associated with §117.105 and §117.205 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section;

(B) for the purposes of §117.106 and §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations) and each requirement of this chapter associated with §117.106 and §117.206 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, or any other stationary source of nitrogen oxides (NO_x) at a major source, as defined in this section; or

(C) for the purposes of §117.475 of this title (relating to Emission Specifications) and each requirement of this chapter associated with §117.475 of this title, any boiler, process heater, stationary gas turbine (including any duct burner in the turbine exhaust duct), or stationary internal combustion engine, as defined in this section.

(52) **Utility boiler** - Any combustion equipment owned or operated by a municipality or Public Utility Commission of Texas regulated utility, fired with solid, liquid, and/or gaseous fuel, used to produce steam for the purpose of generating electricity. Stationary gas turbines, including any associated duct burners and unfired waste heat boilers, are not considered to be utility boilers.

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

SUBCHAPTER B: COMBUSTION AT MAJOR SOURCES
DIVISION 1: UTILITY ELECTRIC GENERATION IN OZONE NONATTAINMENT AREAS

STATUTORY AUTHORITY
The repeal is adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The repeal is also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§117.104. Gas-Fired Steam Generation.

SUBCHAPTER B: COMBUSTION AT MAJOR SOURCES
DIVISION 1: UTILITY ELECTRIC GENERATION IN OZONE NONATTAINMENT AREAS
§§117.105 - 117.108, 117.113 - 117.116, 117.119, 117.121

STATUTORY AUTHORITY
The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

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

(a) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pound per million British thermal units (lb/MMBtu) heat input on a rolling 24-hour average and 0.20 lb/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, NO_x emissions in excess of 0.38 lb/MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 lb/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 or auxiliary steam boiler, NO_x emissions in excess of 0.30 lb/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 or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission limits specified in subsections (a) and (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)

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), (c), or (d) 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 lb/MMBtu heat input while firing natural gas; and

(2) 0.30 lb/MMBtu heat input while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any utility boiler 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 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), based on:

(1) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (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 ten 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 in accordance with 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 in Ozone Nonattainment Areas) 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 in accordance with 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.

(l) This section shall no longer apply:

(1) to any utility boiler in the Beaumont/Port Arthur ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(a)(2) of this title;

(2) to any utility boiler in the Dallas/Fort Worth ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(b)(2) of this title; and

(3) in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(c)(2) of this title. For purposes of this paragraph, this means that the RACT emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston/Galveston mass

emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of this section.

§117.106. Emission Specifications for Attainment Demonstrations.

(a) Beaumont/Port Arthur. The owner or operator of each utility boiler located in the Beaumont/Port Arthur ozone nonattainment area shall ensure that emissions of nitrogen oxides (NO_x) do not exceed 0.10 pound per million Btu (lb/MMBtu) heat input, on a daily average, except as provided in §117.108 or §117.570 of this title (relating to System Cap; and Use of Emissions Credits for Compliance).

(b) Dallas/Fort Worth. The owner or operator of each utility boiler located in the Dallas/Fort Worth (DFW) ozone nonattainment area shall ensure that emissions of NO_x do not exceed: 0.033 lb/MMBtu heat input from boilers which are part of a large DFW system, and 0.06 lb/MMBtu heat input from boilers which are part of a small DFW system, on a daily average, except as provided in §117.108 or §117.570 of this title. The annual heat input exemption of §117.103(2) of this title (relating to Exemptions) is not applicable to a small DFW system.

(c) Houston/Galveston. The owner or operator of each utility boiler, auxiliary steam boiler, or stationary gas turbine located in the Houston/Galveston ozone nonattainment area shall ensure that emissions of NO_x do not exceed the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the following rates, in lb/MMBtu heat input, on the basis of daily and 30-day averaging periods as specified in §117.108 of this title, and as specified in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program):

(1) utility boilers:

(A) gas-fired, 0.030; and

(B) coal-fired or oil-fired:

(i) wall-fired, 0.050; and

(ii) tangential-fired, 0.045;

(2) auxiliary steam boilers, 0.030; and

(3) stationary gas turbines (including duct burners used in turbine exhaust ducts), 0.032.

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

(1) carbon monoxide (CO) emissions in excess of 400 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), based on:

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

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

(2) for units which inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions in excess of ten ppmv, at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(e) Compliance flexibility.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, 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; or

(B) §117.570 of this title.

(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.

(4) In the Houston/Galveston ozone nonattainment area, the following requirements apply.

(A) For units which meet the definition of electric generating facility (EGF), the owner or operator must use both the methods specified in §117.108 of this title and the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NO_x emission specifications of this section. An owner or operator may use the alternative methods specified in §117.570 of this title for purposes of complying with §117.108 of this title.

(B) For units which do not meet the definition of EGF, the owner or operator must use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply 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(14)(A) of this title (relating to Definitions) would not exceed the system-wide emission limit as defined in §117.10 of this title.

(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 shall have a separate system average under this section, limited to those units.

(3) Oil-fired utility boilers 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 (lb) NO_x per million British thermal units (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 lb/MMBtu:

(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 lb/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 lb/MMBtu on a rolling 24-hour averaging period.

(c) An owner or operator of any gaseous and liquid fuel-fired utility boiler 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 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)

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.

(e) This section shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(c)(2) of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas). For purposes of this subsection, this means that the alternative plant-wide emission specifications of this section remain in effect until the emissions allocation for units under the Houston/Galveston mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide emission specifications of this section.

§117.108. System Cap.

(a) An owner or operator of an electric generating facility (EGF) in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment areas 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. An owner or operator of an EGF in the Houston/Galveston ozone nonattainment area must comply with a daily and 30-day system cap emission limitation in accordance with the requirements of this section.

(b) Each EGF within an electric power generating system, as defined in §117.10(14)(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)

$$\begin{array}{c}\text{NO}_x \text{ 30-day rolling} \\ \text{average emission cap} \\ \text{(lb/day)}\end{array} = \sum_{i=1}^{N} (H_i \times R_i)$$

Where:

i = each EGF in the electric power generating system

N = the total number of EGFs in the emission cap

H_i = (A) For the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, the average of the daily heat input for each EGF 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 EGFs exempt from the 40 Code of Federal Regulations (CFR) Part 75 monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for EGFs 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.

(B) For the Houston/Galveston ozone nonattainment area:

(i) The average of the daily heat input for each EGF in the emission cap, in million Btu per day, as certified to the executive director, for any system 30-day period in the nine months of July, August, and September 1997, 1998, and 1999;

(ii) For EGFs exempt from the 40 CFR Part 75 monitoring requirements, if the heat input data corresponding to any system 30-day period (as determined for EGFs in the system subject to 40 CFR Part 75 monitoring) is not available, the daily average of the highest calendar month heat input in 1997-1999 may be used; and

(iii) The level of activity authorized by the executive director for the third quarter (July, August, and September), until such time two consecutive third quarters of actual level of activity data are available, shall be used for the following:

(I) EGFs for which the owner or operator has submitted, under Chapter 116 of this title, an application determined to be administratively complete by the executive director before January 2, 2001;

(II) EGFs which qualify for a permit by rule under Chapter 106 of this title and have commenced construction before January 2, 2001; and

(III) EGFs which were not in operation before January 1, 1997;

(iv) After two consecutive third quarters of actual level of activity data are available for an EGF described in subsection (c)(1) of this section, variable (B)(iii) of this figure, the owner or operator may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions); and

(v) In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period described in subsection (c)(1) of this section, variable (B)(i) - (iv) of this figure. Applications seeking an alternate baseline period must be submitted by the owner or operator of the EGF to the executive director:

(I) no later than December 31, 2001; or

(II) for EGFs for which the baseline period as described in subsection (c)(1) of this section, variable (B)(i) - (iv) of this figure is not complete by December 31, 2001, no later than 90 days after completion of the baseline period.

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

(B) For EGFs in the Dallas/Fort Worth ozone nonattainment area, the emission limit of §117.106(b) of this title; and

(C) For EGFs in the Houston/Galveston ozone nonattainment area, the emission limit of §117.106(c) of this title.

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

Figure: 30 TAC §117.108(c)(2)

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

Where:

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

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

(3) Each EGF 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 EGF in the system cap shall be used to demonstrate continuous compliance with the system cap.

(e) For each operating EGF, 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 Code of Federal Regulations (CFR) Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(B) subject to 40 CFR Part 75, Appendix E, use the missing data procedures specified in 40 CFR Part 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 Part 75, Subpart D; or

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

(4) if the methods specified in paragraphs (1) - (3) of this subsection are not used, the owner or operator must use the maximum block one-hour emission rate as measured by the 30-day testing.

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

(g) The owner or operator of any EGF 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 EGF 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) For the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, an EGF 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. For the Houston/Galveston ozone nonattainment area, an EGF 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, 2000. 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 EGF 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.

§117.113. 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. Each NO_x monitor (CEMS or PEMS) in the Beaumont/Port

Arthur, Dallas/Fort Worth, or Houston/Galveston ozone nonattainment area is subject to the relative accuracy test audit (RATA) relative accuracy requirements of 40 Code of Federal Regulations (CFR) Part 75, Appendix B, Figure 2, except the concentration options (parts per million by volume (ppmv) and pound per million British thermal units (lb/MMBtu)) therein do not apply. Each NO_x monitor shall meet either the relative accuracy percent requirement of 40 CFR Part 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of $\pm$ 2.0 ppmv from the reference method mean value.

(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 Part 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 Part 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 Part 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) For units which are subject to §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), and for units in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment area, 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.

(3) For units in the Houston/Galveston ozone nonattainment area which are subject to §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations):

(A) all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack;

(B) one CEMS may be shared among units, provided:

(i) the exhaust stream of each stack is analyzed separately; and

(ii) the CEMS meets the certification requirements of paragraph (1) of this subsection for each stack while the CEMS is operating in the time-shared mode; and

(C) exhaust streams of units which vent to a common stack do not need to be analyzed separately.

(d) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR §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 EPA; or

(B) using a PEMS.

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

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

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

(B) §117.213(f) of this title.

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

(1) for stationary gas turbines rated less than 30 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 $\pm 5.0\%$. 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 stationary 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. In lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. The units are:

(1) for units which are subject to §117.105 of this title, and for units in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas which are subject to §117.106 of this title:

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

(B) 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

(C) 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); and

(2) for units in the Houston/Galveston ozone nonattainment area ozone nonattainment area which are subject to §117.106 of this title:

(A) utility boilers;

(B) auxiliary steam boilers; and

(C) stationary gas turbines.

(i) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.103(a)(3) or (b) 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.

(1) 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 §117.105 or §117.106(a) or (b) of this title. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission compliance method.

(2) For units subject to the emission specifications of §117.106(c) of this title, the methods required in this section and §117.114 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) shall be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) to determine compliance. 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 RACT 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 in accordance with §117.115(b) of this title (relating to Final Control Plan Procedures).

§117.114. Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration.

(a) Monitoring requirements. The owner or operator of units which are subject to the emission limits of §117.106(c) of this title (relating to Emission Specifications for Attainment Demonstrations) must comply with the following monitoring requirements.

(1) The nitrogen oxides (NO_x) monitoring requirements of §117.113(a) and (c) - (f) of this title (relating to Continuous Demonstration of Compliance) apply.

(2) The carbon monoxide (CO) monitoring requirements of §117.113(b) of this title apply.

(3) The totalizing fuel flow meter requirements of §117.113(h) of this title apply.

(4) One of the following ammonia monitoring procedures shall be used to demonstrate compliance with the ammonia emission specification of §117.106(d)(2) of this title for gas-fired or liquid-fired units which inject urea or ammonia into the exhaust stream for NO_x control.

(A) Mass balance. Calculate ammonia emissions as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of the control device which injects urea or ammonia into the exhaust stream. The equation is: ammonia parts per million by volume (ppmv) at reference oxygen $=\{(a/b)(10^6) - (c)(d)\}$, where reference oxygen is 3.0% for boilers and 15% for gas turbines; a = ammonia injection rate (in pounds per hour (lb/hr))/17 pound per pound-mole (lb/lb-mol); b = dry exhaust flow rate (lb/hr)/29 lb/lb-mol; c = change in measured NO_x concentration across catalyst (ppmv at reference oxygen); and d = correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia required by §117.111(a)(2) of this title (relating to Initial Demonstration of Compliance), using either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27.

(B) Oxidation of ammonia to nitric oxide (NO). Convert ammonia to NO using molybdenum oxidizer and measure ammonia slip by difference using a NO analyzer. The NO analyzer shall be quality assured in accordance with manufacturer's specifications and with a quarterly cylinder gas audit with a ten ppmv reference sample of ammonia passed through the probe and confirming monitor response to within ± 2.0 ppmv.

(C) Stain tubes. Measure ammonia using a sorbent or stain tube device specific for ammonia measurement in the 5.0 to 10.0 ppmv range. The frequency of sorbent/stain tube testing shall be daily for the first 60 days of operation, after which the frequency may be reduced to weekly testing if operating procedures have been developed to prevent excess amounts of ammonia from being introduced in the control device and when operation of the control device has been proven successful with regard to controlling ammonia slip. Daily sorbent or stain tube testing shall resume when the catalyst is within 30 days of its useful life expectancy. Every effort shall be made to take at least one weekly sample near the normal highest ammonia injection rate.

(D) Other methods. Monitor ammonia using another continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) procedure subject to prior approval of the executive director. For purposes of this subparagraph, the executive director is the Engineering Services Team, Office of Compliance and Enforcement.

(E) Records. The owner or operator shall maintain records which are sufficient to demonstrate compliance with the requirements of the appropriate subparagraph of this paragraph. For the sorbent or stain tube option, these records shall include the ammonia injection rate and NO_x stack emissions measured during each sorbent or stain tube test. The records shall be maintained for a period of at least five years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request.

(5) Installation of monitors shall be performed in accordance with the schedule specified in §117.510(c)(2) of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(b) Testing requirements. The owner or operator of units which are subject to the emission limits of §117.106(c) of this title must test the units as specified in §117.111 of this title in accordance with the schedule specified in §117.510(c)(2) of this title.

(c) Emission allowances.

(1) The NO_x testing and monitoring data of subsections (a) and (b) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), shall be used to establish the emission factor for calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

(2) For units not operating with a CEMS or PEMS, the following apply.

(A) Retesting as specified in subsection (b) of this section is required within 60 days after any modification which could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in subsection (b) of this section may be conducted at the discretion of the owner or operator after any modification which could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation (FGR), and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions from the date of the retesting forward. Until the date of the retesting, the previously determined emission factor shall be used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(D) All test reports must be submitted to the executive director for review and approval within 60 days after completion of the testing.

(3) The emission factor in paragraph (1) or (2) of this subsection is multiplied by the unit's level of activity to determine the unit's actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

§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 for each non-exempt unit;

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

(A) §117.105 of this title;

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

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

(D) §117.570 of this title (relating to Use of Emissions Credits for Compliance);

(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 Use of Emissions Credits for Compliance); or

(D) Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program);

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

(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.

§117.119. Notification, Recordkeeping, and Reporting Requirements.

(a) Startup and shutdown records. For units subject to the startup and/or shutdown exemptions allowed under §101.222 of this title (relating to Demonstrations), hourly records shall be made of startup 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 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 appropriate regional office and any local air pollution control agency having jurisdiction as follows:

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

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (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 Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any 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) §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 stationary 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 startups, 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, in accordance with §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 (CO) or ammonia limits of §117.106(d) of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.105 of this title or the CO or ammonia limits in §117.106(d) 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 controls to meet the nitrogen oxides emission specifications of §117.105 or §117.106 of this title, as applicable;

(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; and

(4) is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director’s Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the EPA 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).

DIVISION 2: UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS
§§117.131, 117.135, 117.138, 117.141, 117.143, 117.149, 117.151

STATUTORY AUTHORITY
The amendments and new section are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments and new section are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§117.131. Applicability.

(a) The provisions of this division (relating to Utility Electric Generation in East and Central Texas) shall apply to each utility electric power boiler and stationary gas turbine (including duct burners used in turbine exhaust ducts) that:

(1) generates electric energy for compensation;

(2) is owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility, or any of its successors;

(3) was placed into service before December 31, 1995; and

(4) is located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County.

(b) The provisions of §117.134 of this title (relating to Gas-Fired Steam Generation) also apply in Palo Pinto County.

§117.135. Emission Specifications.

In accordance with the compliance schedule in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas), the owner or operator of each utility electric power boiler or stationary gas turbine (including duct burners used in turbine exhaust ducts) shall:

(1) ensure that emissions of nitrogen oxide (NO_x) do not exceed the following rates, in pound per million British thermal unit (lb/MMBtu) heat input on an annual (calendar year) average:

(A) electric power boilers:

(i) gas-fired, 0.14;

(ii) coal-fired, 0.165;

(B) stationary gas turbines (including duct burners used in turbine exhaust ducts):

(i) subject to Texas Utilities Code (TUC), §39.264 (except units designated in accordance with TUC, §39.264(i)), 0.14;

(ii) not subject to TUC, §39.264, 0.15 (or alternatively, 42 parts per million by volume (ppmv) NO_x, adjusted to 15% oxygen (O_2), dry basis); and

(iii) units designated in accordance with TUC, §39.264(i), 0.15 (or alternatively, 42 ppmv NO_x, adjusted to 15% O_2, dry basis); and

(2) ensure that for units which inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions do not exceed ten ppmv at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts) from any unit subject to the NO_x emission limits specified in paragraph (1) of this section, based on:

(A) a block one-hour averaging period for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia. One of the ammonia monitoring procedures specified in §117.114(a)(4) of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) shall be used to demonstrate compliance with the ammonia emission specification of this subparagraph.

§117.138. System Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.135 of this title (relating to Emission Specifications) by achieving equivalent NO_x emission reductions obtained by compliance with a system cap emission limitation in accordance with the requirements of this section.

(b) Each unit within an electric power generating system, as defined in §117.10(14)(B) of this title (relating to Definitions), that would otherwise be subject to the NO_x emission limits of §117.135 of this title must be included in the system cap.

(c) The annual average emission cap shall be calculated using the following equation.

Figure: 30 TAC §117.138(c)

$$\begin{array}{c}NO_x \text{ annual} \\ \text{average emission cap} \\ \text{(tons/year)}\end{array} = \sum_{i=1}^{N} (H_i \times R_i)/2000$$

Where:

i	=	Each unit in the electric power generating system
N	=	The total number of units in the emission cap
H_i	=	The average of the annual heat input for each unit in the emission cap, in million British thermal units (Btu) per year, as certified to the executive director, for 1996, 1997, and 1998
R_i	=	The emission limit of §117.135 of this title

(d) The NO_x emissions monitoring required by §117.143 of this title (relating to Continuous Demonstration of Compliance) for each unit in the system cap shall be used to demonstrate continuous compliance with the system cap.

(e) For each operating unit, 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 Code of Federal Regulations (CFR) Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures);

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

(2) use Appendix E monitoring in accordance with §117.143(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 Part 75, Subpart D;

(B) use calculations in accordance with §117.143(e) of this title; or

(4) if the methods specified in paragraphs (1) - (3) of this subsection are not used, the owner or operator must use the maximum emission rate as measured by the testing conducted in accordance with §117.141(d) of this title (relating to Initial Demonstration of Compliance).

(f) The owner or operator of any unit subject to a system cap shall maintain daily records indicating the NO_x emissions and fuel usage from each unit and summations of total NO_x emissions and fuel usage for all units under the system cap on a daily basis. Records shall also be retained in accordance with §117.149 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator of any unit subject to a system cap shall submit annual reports for the monitoring systems in accordance with §117.149 of this title. The owner or operator shall also report any exceedance of the system cap emission limit in the annual report and shall include 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.

(h) The owner or operator of any unit subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(i) A unit which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, provided that the permanent shutdown occurred on or 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 unit 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 EPA that actual emissions were less than maximum emissions during such periods.

§117.141. Initial Demonstration of Compliance.

(a) The owner or operator of all units which are subject to the emission limitations of §117.135 of this title (relating to Emission Specifications) 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 schedule specified in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(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 (relating to Utility Electric Generation in East and Central Texas). 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 §117.143 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, at 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 §117.143 of this title shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows. To comply with the NO_x emission limit in pound per million British thermal units (lb/MMBtu) on an annual average, NO_x emissions from a unit are monitored for each unit operating day in a calendar year, and the annual average emission rate is used to determine compliance with the NO_x emission limit. The annual average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during a calendar year.

§117.143. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Utility Electric Generation in East and Central Texas) 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 NO_x on an individual basis.

(b) Carbon monoxide (CO) monitoring. If the owner or operator chooses to monitor CO exhaust emissions from a unit subject to the emission specifications of this division, the following methods should be considered appropriate guidance for determining CO emissions:

(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 Code of Federal Regulations (CFR) Part 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 Part 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 Part 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 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.

(3) As an alternative to paragraph (2) of this subsection, for units which are included in a system cap under §117.138 of this title (relating to System Cap):

(A) all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack;

(B) one CEMS may be shared among units, provided:

(i) the exhaust stream of each stack is analyzed separately; and

(ii) the CEMS meets the certification requirements of paragraph (1) of this subsection for each stack while the CEMS is operating in the time-shared mode; and

(C) exhaust streams of units which vent to a common stack do not need to be analyzed separately.

(d) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR §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) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section must comply with the following. The required PEMS and fuel flow meters shall be used to demonstrate continuous compliance with the emission limitations of §117.135 of this title (relating to Emission Specifications).

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

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

(A) using a CEMS:

(i) in accordance with subsection (c) 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 for units subject to the requirements of 40 CFR Part 75 shall meet the requirements of 40 CFR §§75.40 - 75.48.

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

(A) 40 CFR §§75.40 - 75.48; or

(B) §117.213(f) of this title (relating to Continuous Demonstration of Compliance).

(f) Gas turbine monitoring. The owner or operator of each stationary gas turbine subject to the emission specifications of §117.135 of this title, instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR Part 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 megawatt (MW) or peaking gas turbines (as defined in §117.10 of this title (relating to Definitions)) which use steam or water injection to comply with the emission specification of §117.135(1)(B) of this title:

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

(B) for units which are not included in a system cap under §117.138 of this title, 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 emission specification of §117.135(1)(B) of this title; and

(2) for gas turbines not subject to paragraph (1) of this subsection, install, calibrate, maintain, and operate a CEMS or PEMS in compliance with this section.

(g) 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 an average of 10% of the hours of the year, averaged over the three most recent calendar years, or more than 20% of the hours in a single calendar year; and

(3) any unit claimed exempt from the emission specifications of this division using the exemption of §117.133(1) of this title (relating to Exemptions).

(h) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.133(2) of this title shall record the operating time with an elapsed run time meter approved by the executive director.

(i) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the exemptions of §117.133 of this title, shall notify the executive director within seven days if the applicable limit is exceeded.

(l) If the limit is exceeded, the exemption from the emission specifications of §117.135 of this title shall be permanently withdrawn.

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

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

(j) Data used for compliance. After the initial demonstration of compliance required by §117.141 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.

(k) Enforcement of NO_x limits. No unit subject to §117.135 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.135 of this title.

§117.149. Notification, Recordkeeping, and Reporting Requirements.

(a) Startup and shutdown records. For units subject to the startup and/or shutdown exemptions allowed under §101.222 of this title (relating to Demonstrations), hourly records shall be made of startup 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 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 East and Central Texas) shall submit notification to the executive director as follows:

(1) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.141 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 §117.143 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 §117.141 of this title or any CEMS or PEMS performance evaluation conducted under §117.143 of this title:

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

(2) not later than the appropriate compliance schedule specified in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(d) Annual 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 §117.143 of this title shall report in writing to the executive director on an annual basis any exceedance of the applicable emission limitations in this division and the monitoring system performance. All reports shall be postmarked or received by January 31 following the end of each calendar year. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations (CFR) §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period. For stationary gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.143 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 §117.141 of this title;

(2) specific identification of each period of excess emissions that occurs during startups, 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; and

(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 in accordance with §117.143 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 §117.141 of this title; and

(7) records of hours of operation.

§117.151. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the ammonia limit of §117.135(2) of this title (relating to Emission Specifications), the executive director may approve emission specifications different from the ammonia limit in §117.135(2) 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 controls to meet the nitrogen oxides emission specifications of §117.135 of this title;

(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; and

(4) is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director’s Decision) apply.

DIVISION 3: INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL COMBUSTION SOURCES IN OZONE NONATTAINMENT AREAS
§§117.203, 117.205 - 117.207, 117.213 - 117.216, 117.219, 117.221, 117.223

STATUTORY AUTHORITY
The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§117.203. Exemptions.

(a) 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 §§117.206(i), 117.209(c)(1), 117.213(i), 117.214(a)(2), 117.216(a)(5), and 117.219(f)(6) and (10) of this title (relating to Emission Specifications for Attainment Demonstrations; Initial Control Plan Procedures; Continuous Demonstration of Compliance; Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration; Final Control Plan Procedures for Attainment Demonstration Emission Specifications; and Notification, Recordkeeping, and Reporting Requirements), include the following:

(1) any new units placed into service after November 15, 1992, except for new units which are qualified, at the option of the owner or operator, as functionally identical replacement for existing units under §117.205(a)(3) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). 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 industrial, commercial, or institutional boiler or process heater with a maximum rated capacity of less than 40 million British thermal units per hour (MMBtu/hr);

(3) heat treating furnaces and reheat furnaces. This exemption shall no longer apply to any heat treating furnace or reheat furnace with a maximum rated capacity of 20 MMBtu/hr or greater in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for

emission specifications for attainment demonstrations specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas);

(4) flares, incinerators, pulping liquor recovery furnaces, sulfur recovery units, sulfuric acid regeneration units, molten sulfur oxidation furnaces, and sulfur plant reaction boilers. This exemption shall no longer apply to the following units in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title:

(A) incinerators with a maximum rated capacity of 40 MMBtu/hr or greater; and

(B) pulping liquor recovery furnaces;

(5) dryers, kilns, or ovens used for drying, baking, cooking, calcining, and vitrifying. This exemption shall no longer apply to the following units in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title:

(A) magnesium chloride fluidized bed dryers; and

(B) lime kilns and lightweight aggregate kilns;

(6) stationary gas turbines and stationary internal combustion engines, which are used as follows:

(A) in research and testing;

(B) for purposes of performance verification and testing;

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

(D) exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after October 1, 2001 in the Houston/Galveston ozone nonattainment area is ineligible for this exemption. For the purposes of this subparagraph, the terms “modification” and “reconstruction” have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

(E) in response to and during the existence of any officially declared disaster or state of emergency;

(F) directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals; or

(G) as chemical processing gas turbines;

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

(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;

(9) any boiler or process heater with a maximum rated capacity of 2.0 MMBtu/hr or less;

(10) any stationary diesel engine in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area;

(11) any stationary diesel engine placed into service before October 1, 2001 in the Houston/Galveston ozone nonattainment area which:

(A) operates less than 100 hours per year, based on a rolling 12-month average; and

(B) has not been modified, reconstructed, or relocated on or after October 1, 2001. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(12) any new, modified, reconstructed, or relocated stationary diesel engine placed into service in the Houston/Galveston ozone nonattainment area on or after October 1, 2001 which:

(A) operates less than 100 hours per year, based on a rolling 12-month average, in other than emergency situations; and

(B) meets the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this paragraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account.

(b) The exemptions in subsection (a)(1), (2), (7), and (8)(A) of this section shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title.

§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, 117.223, or 117.570 of this title (relating to Alternative Plant-wide Emission Specifications; Source Cap; and Use of Emissions Credits for Compliance).

(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 in accordance with 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 (lb NO_x/MMBtu) 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 lb NO_x/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) 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 in accordance with 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 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. The following equation shall be used by an owner or operator using a gas-fired boiler or process heater which is subject to this paragraph and one of the rolling 30-day averaging period emission limitations contained in paragraph (1) or (2) of this subsection to calculate an emission limitation for each rolling 30-day period:

Figure: 30 TAC §117.205(b)(6)

$$EL_2 = \frac{(EL_1)(1.25)(T_1) + (EL_1)(T_2)}{(T_1 + T_2)}$$

EL_2 = Time-weighted emission limitation for each 30-day period, in lb NO_x/MMBtu of heat input.
EL_1 = Appropriate emission limitation for gas-fired boiler from §117.205(b)(1)(A) - (F) of this title or gas-fired process heaters from §117.205(b)(2)(A) - (B) of this section, in lb NO_x/MMBtu of heat input.
1.25 = Factor used as a multiplier times the appropriate emission limitation when firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period.
T_1 = Time in hours when firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period during each 30-day period. The time period when hydrogen rich fuel is combusted must, at a minimum, be a consecutive eight-hour period to be used in the determination of T_1.
T_2 = Time in hours when firing gaseous fuel or hydrogen rich fuel (for less than eight consecutive hours) during each 30-day period;

(7) for units which operate with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (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 (lb NO_x/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 lb NO_x/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 megawatt (MW) rating greater than or equal to 10.0 MW, emissions in excess of a block one-hour average concentration of 42 parts per million by volume (ppmv) NO_x and 132 ppmv carbon monoxide (CO) at 15% oxygen (O_2), dry basis. For stationary gas turbines equipped with CEMS or PEMS for CO, the owner or operator may elect to comply with the CO limit of this subsection using a 24-hour rolling average.

(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 30-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 industrial, commercial, or institutional 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 EPA 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, CO furnaces, and catalyst regenerator vents);

(5) duct burners 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;

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

(8) 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;

(9) stationary gas turbines and engines, which are demonstrated to operate less than 850 hours per year, based on a rolling 12-month average; and

(10) 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.

(i) This section shall no longer apply:

(1) to any gas-fired boiler or process heater in the Beaumont/Port Arthur ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(a)(3) of this title; and

(2) in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(c)(2) of this title. For purposes of this paragraph, this means that the RACT emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston/Galveston mass emissions cap are equal to or less than the allocation that would be calculated using the RACT emission specifications of this section.

§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 British thermal units per hour (MMBtu/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 (f) and (g) 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 (f) and (g) 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 3.0% oxygen (O_2), dry basis; and

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

(c) Houston/Galveston. In the Houston/Galveston ozone nonattainment area, the emission rate values used to determine allocations for Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) shall be the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the following emission specifications:

(1) gas-fired boilers:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.020 lb NO_x per MMBtu;

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.030 lb NO_x per MMBtu; and

(C) with a maximum rated capacity less than 40 MMBtu/hr, 0.036 lb NO_x per MMBtu (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis);

(2) fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents), one of the following:

(A) 40 ppmv NO_x at 0.0% O_2, dry basis;

(B) a 90% NO_x reduction of the exhaust concentration used to calculate the June - August 1997 daily NO_x emissions. To ensure that this emission specification will result in a real 90% reduction in actual emissions, a consistent methodology shall be used to calculate the 90% reduction; or

(C) alternatively, for units which did not use a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) to determine the June - August 1997 exhaust concentration, the owner or operator may:

(i) install and certify a NO_x CEMS or PEMS as specified in §117.213(e) or (f) of this title (relating to Continuous Demonstration of Compliance) no later than June 30, 2001;

(ii) establish the baseline NO_x emission level to be the third quarter 2001 data from the CEMS or PEMS;

(iii) provide this baseline data to the executive director no later than October 31, 2001; and

(iv) achieve a 90% NO_x reduction of the exhaust concentration established in this baseline;

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

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.015 lb NO_x per MMBtu; and

(B) with a maximum rated capacity less than 100 MMBtu/hr:

(i) 0.030 lb NO_x per MMBtu; or

(ii) an 80% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions. To ensure that this emission specification will result in a real 80% reduction in actual emissions, a consistent methodology shall be used to calculate the 80% reduction;

(4) coke-fired boilers, 0.057 lb NO_x per MMBtu;

(5) wood fuel-fired boilers, 0.060 lb NO_x per MMBtu;

(6) rice hull-fired boilers, 0.089 lb NO_x per MMBtu;

(7) liquid-fired boilers, 2.0 lb NO_x per 1,000 gallons of liquid burned;

(8) process heaters:

(A) other than pyrolysis reactors:

(i) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, 0.025 lb NO_x per MMBtu; and

(ii) with a maximum rated capacity less 40 MMBtu/hr, 0.036 lb NO_x per MMBtu (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis); and

(B) pyrolysis reactors, 0.036 lb NO_x per MMBtu;

(9) stationary, reciprocating internal combustion engines:

(A) gas-fired rich-burn engines:

(i) fired on landfill gas, 0.60 g NO_x/hp-hr; and

(ii) all others, 0.50 g NO_x/hp-hr;

(B) gas-fired lean-burn engines, except as specified in subparagraph (C) of this paragraph:

(i) fired on landfill gas, 0.60 g NO_x/hp-hr; and

(ii) all others, 0.50 g NO_x/hp-hr;

(C) dual-fuel engines:

(i) with initial start of operation on or before December 31, 2000, 5.83 g NO_x/hp-hr; and

(ii) with initial start of operation after December 31, 2000, 0.50 g NO_x/hp-hr; and

(D) diesel engines, excluding dual-fuel engines:

(i) placed into service before October 1, 2001 which have not been modified, reconstructed, or relocated on or after October 1, 2001, the lower of 11.0 g NO_x/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 CFR §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account; and

(ii) for engines not subject to clause (i) of this subparagraph:

(I) with a horsepower rating of less than 11 hp which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2004, 7.0 g NO_x/hp-hr; and

(-b-) on or after October 1, 2004, 5.0 g NO_x/hp-hr;

(II) with a horsepower rating of 11 hp or greater, but less than 25 hp, which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2004, 6.3 g NO_x/hp-hr; and

(-b-) on or after October 1, 2004, 5.0 g NO_x/hp-hr;

(III) with a horsepower rating of 25 hp or greater, but less than 50 hp, which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2003, 6.3 g NO_x/hp-hr; and

(-b-) on or after October 1, 2003, 5.0 g NO_x/hp-hr;

(IV) with a horsepower rating of 50 hp or greater, but less than 100 hp, which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2003, 6.9 g NO_x/hp-hr;

(-b-) on or after October 1, 2003, but before October 1, 2007, 5.0 g NO_x/hp-hr; and

(-c-) on or after October 1, 2007, 3.3 g NO_x/hp-hr;

(V) with a horsepower rating of 100 hp or greater, but less than 175 hp, which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2002, 6.9 g NO_x/hp-hr;

(-b-) on or after October 1, 2002, but before October 1, 2006, 4.5 g NO_x/hp-hr; and

(-c-) on or after October 1, 2006, 2.8 g NO_x/hp-hr;

(VI) with a horsepower rating of 175 hp or greater, but less than 300 hp, which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2002, 6.9 g NO_x/hp-hr;

(-b-) on or after October 1, 2002, but before October 1, 2005, 4.5 g NO_x/hp-hr; and

(-c-) on or after October 1, 2005, 2.8 g NO_x/hp-hr;

(VII) with a horsepower rating of 300 hp or greater, but less than 600 hp, which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2005, 4.5 g NO_x/hp-hr; and

(-b-) on or after October 1, 2005, 2.8 g NO_x/hp-hr;

(VIII) with a horsepower rating of 600 hp or greater, but less than or equal to 750 hp, which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2005, 4.5 g NO_x/hp-hr; and

(-b-) on or after October 1, 2005, 2.8 g NO_x/hp-hr; and

(IX) with a horsepower rating of 750 hp or greater which are installed, modified, reconstructed, or relocated:

(-a-) on or after October 1, 2001, but before October 1, 2005, 6.9 g NO_x/hp-hr; and

(-b-) on or after October 1, 2005, 4.5 g NO_x/hp-hr;

(10) stationary gas turbines:

(A) rated at ten megawatts (MW) or greater, 0.032 lb NO_x per MMBtu;

(B) rated at 1.0 MW or greater, but less than ten MW, 0.15 lb NO_x per MMBtu; and

(C) rated at less than 1.0 MW, 0.26 lb NO_x per MMBtu;

(11) duct burners used in turbine exhaust ducts, the corresponding gas turbine emission specification of paragraph (10) of this subsection;

(12) pulping liquor recovery furnaces, either:

(A) 0.050 lb NO_x per MMBtu; or

(B) 1.08 lb NO_x per air-dried ton of pulp (ADTP);

(13) kilns:

(A) lime kilns, 0.66 lb NO_x per ton of calcium oxide (CaO); and

(B) lightweight aggregate kilns, 1.25 lb NO_x per ton of product;

(14) metallurgical furnaces:

(A) heat treating furnaces, 0.087 lb NO_x per MMBtu; and

(B) reheat furnaces, 0.062 lb NO_x per MMBtu;

(15) magnesium chloride fluidized bed dryers, a 90% reduction from the emission factor used to calculate the 1997 ozone season daily NO_x emissions;

(16) incinerators, either of the following:

(A) an 80% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions. To ensure that this emission specification will result in a real 80% reduction in actual emissions, a consistent methodology shall be used to calculate the 80% reduction; or

(B) 0.030 lb NO_x per MMBtu; and

(17) as an alternative to the emission specifications in paragraphs (1) - (16) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb NO_x per MMBtu. For units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor shall be used to determine whether the unit is eligible for the emission specification of this paragraph. For units placed into service after January 1, 1997, the annual capacity factor shall be calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph, using the same two consecutive years chosen for the activity level baseline. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions).

(d) NO_x averaging time.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, the emission limits of subsections (a) and (b) of this section shall apply:

(A) if the unit is operated with a NO_x CEMS or PEMS under §117.213 of this title, either as:

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

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

(iii) 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

(B) 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 subparagraph (A)(iii) of this paragraph.

(2) In the Houston/Galveston ozone nonattainment area, the averaging time for the emission limits of subsection (c) of this section shall be as specified in Chapter 101, Subchapter H, Division 3 of this title, except that electric generating facilities (EGFs) shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title (relating to System Cap).

(e) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (a), (b), or (c) of this section, emissions in excess of the following, except as provided in §117.221 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection:

(1) carbon monoxide (CO), 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines; or 775 ppmv at 7.0% O_2, dry basis for wood fuel-fired boilers or process heaters):

(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) for units which inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions of ten ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), gas-fired lean-burn engines, and lightweight aggregate kilns; 0.0% O_2, dry, for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents); 7.0% O_2, dry, for BIF units which were regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993), wood-fired boilers, and incinerators; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(3) The correction of CO emissions to 3.0% O_2, dry basis, in paragraph (1) of this subsection does not apply to the following units:

(A) lightweight aggregate kilns; and

(B) boilers and process heaters operating at less than 10% of maximum load and with stack O_2 in excess of 15% (i.e., hot-standby mode).

(4) The CO limits in paragraph (1) of this subsection do not apply to the following units:

(A) stationary internal combustion engines subject to subsection (b)(2) of this section or §117.205(e) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT));

(B) BIF units which were regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993) and which are subject to subsection (c)(3) of this section; and

(C) incinerators subject to the CO limits of one of the following:

(i) §111.121 of this title (relating to Single-, Dual-, and Multiple-Chamber Incinerators);

(ii) §113.2072 of this title (relating to Emission Limits) for hospital/medical/infectious waste incinerators; or

(iii) 40 CFR Part 264 or 265, Subpart O, for hazardous waste incinerators.

(f) Compliance flexibility.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, 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 Use of Emissions Credits for Compliance).

(2) Section 117.221 of this title 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.

(4) In the Houston/Galveston ozone nonattainment area, an owner or operator may not use the alternative methods specified in §§117.207, 117.223, and 117.570 of this title to comply with the NO_x emission specifications of this section. The owner or operator shall use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NO_x emission specifications of this section, except that EGFs shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title. An owner or operator may use the alternative methods specified in §117.570 of this title for purposes of complying with §117.210 of this title.

(g) Exemptions. Units exempted from the emissions specifications of this section include the following in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas:

(1) any industrial, commercial, or institutional 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) and (9) of this title.

(h) Prohibition of circumvention. In the Houston/Galveston ozone nonattainment area:

(1) the maximum rated capacity used to determine the applicability of the emission specifications in subsection (c) of this section shall be:

(A) the greater of the following:

(i) the maximum rated capacity as of December 31, 2000; or

(ii) the maximum rated capacity after December 31, 2000; or

(B) alternatively, the maximum rated capacity authorized by a permit issued under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, provided that the maximum rated capacity authorized by the permit issued on or after January 2, 2001 is no less than the maximum rated capacity represented in the permit application as of January 2, 2001;

(2) a unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, a unit that is classified as a boiler as of December 31, 2000, but subsequently is authorized to operate as a BIF unit, shall be classified as a boiler for the purposes of this chapter. In another example, a unit that is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, shall be classified as a stationary gas-fired engine for the purposes of this chapter;

(3) changes after December 31, 2000 to a unit subject to an emission specification in subsection (c) of this section (ESAD unit) which result in increased NO_x emissions from a unit not subject to an emission specification in subsection (c) of this section (non-ESAD unit), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if:

(A) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS which meets the requirements of §117.213(e) or (f) of this title, or through stack testing which meets the requirements of §117.211(e) of this title (relating to Initial Demonstration of Compliance); and

(B) a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made as specified in §101.354 of this title (relating to Allowance Deductions);

(4) a source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of this chapter. A source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of this chapter; and

(5) the availability under subsection (c)(17) of this section of an emission specification for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. Reduced operation after December 31, 2000 cannot be used to qualify for a more lenient emission specification under subsection (c)(17) of this section than would otherwise apply to the unit.

(i) Operating restrictions. In the Houston/Galveston ozone nonattainment area, no person shall start or operate any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon, except:

(1) for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours;

(2) to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair; or

(3) firewater pumps for emergency response training conducted in the months of April through October.

§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 a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (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 British thermal units (lb NO_x/MMBtu) or parts per million by volume (ppmv)), 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 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(g) of this title are also exempt under this section and shall not be included in the plant-wide emission limit, except as follows. The owner or operator of exempted units as defined in §117.205(h) and §117.206(g) of this title may opt to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications.

(1) Low annual capacity factor boilers, process heaters, stationary gas turbines, or stationary internal combustion 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 table titled §117.207(f) OPT-IN UNITS.

Figure: 30 TAC §117.207(f)(4)

§117.207(f) OPT-IN UNITS

Equipment Class/Description	Emission Specification
fluid catalytic cracking unit carbon monoxide (CO) boilers	50% NO_x reduction across the inlet of the CO boiler to the outlet of the CO boiler, with the outlet concentration in ppmv converted into lb NO_x/MMBtu of heat input
lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 hp or greater	5.0 g NO_x/hp-hr under all operating conditions
boilers 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 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 megawatt (MW) rating and International Standards Organization (ISO) flow conditions) and $(46/28)(10^{-6})$;

Figure: 30 TAC §117.207(g)(3)

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 §117.205(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; or

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

(j) This section shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(c)(2) of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas). For purposes of this paragraph, this means that the alternative plant-wide emission specifications of this section remain in effect until the emissions allocation for units under the Houston/Galveston mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide emission specifications of this section.

§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) for units which are subject to §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), for stationary gas turbines which are exempt under §117.205(h)(7) of this title, and for units in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas which are subject to §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations):

(i) 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;

(ii) stationary, reciprocating internal combustion engines not exempt by §117.203(a)(6) or (8) of this title (relating to Exemptions), or §117.205(h)(9) or (10) of this title;

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

(iv) fluid catalytic cracking unit boilers using supplemental fuel; and

(B) for units in the Houston/Galveston ozone nonattainment area which are subject to §117.206 of this title:

(i) boilers (excluding wood-fired boilers);

(ii) process heaters;

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

(iv) duct burners used in turbine exhaust ducts;

(v) stationary, reciprocating internal combustion engines;

(vi) stationary gas turbines;

(vii) fluid catalytic cracking unit boilers and furnaces using supplemental fuel;

(viii) lime kilns;

(ix) lightweight aggregate kilns;

(x) heat treating furnaces;

(xi) reheat furnaces;

(xii) magnesium chloride fluidized bed dryers; and

(xiii) incinerators.

(2) As an alternative to the fuel flow monitoring requirements of this subsection, units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (e) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 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) and (8) - (10) of this title;

(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;

(F) units for which the owner or operator elects to comply with the NO_x emission specifications of §117.205 or §117.206(a) or (b) of this title using a pound per MMBtu (lb/MMBtu) limit on a 30-day rolling average;

(G) lime kilns and lightweight aggregate kilns in the Houston/Galveston ozone nonattainment area;

(H) units with a rated heat input greater than or equal to 100 MMBtu/hr which are subject to §117.206(c) of this title; and

(I) fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents). In addition, the owner or operator shall monitor the stack exhaust flow rate with a flow meter using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

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

(A) for purposes of §117.205 or §117.206(a) or (b) of this title, units listed in §117.205(h)(3) - (5) and (8) - (10) of this title; and

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

(d) 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 Part 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 Part 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 Part 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) Except as specified in paragraph (5) of this subsection, 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 in terms of the applicable standard (in parts per million by volume (ppmv), lb/MMBtu, or grams per horsepower-hour (g/hp-hr)). An alternative relative accuracy requirement of $\pm$ 2.0 ppmv from the reference method mean value is allowed;

(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 or date of required submittal of CEMS performance evaluation, conduct 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. However, if the optional alternative relative accuracy requirement of subparagraph (B)(i) of this paragraph (or equivalent) from the reference method mean value is used, then an annual RATA must be performed.

(2) Monitor diluent, either 0_2 or CO_2, unless using an exhaust flow meter as provided in subsection (a)(2) of this section.

(3) For units which are subject to §117.205 of this title, and for units in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, 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 while the CEMS is operating in the time-shared mode.

(4) For units in the Houston/Galveston ozone nonattainment area which are subject to §117.206 of this title:

(A) all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack;

(B) one CEMS may be shared among units, provided:

(i) the exhaust stream of each stack is analyzed separately;

(ii) the CEMS meets the certification requirements of paragraph (1) of this subsection for each stack while the CEMS is operating in the time-shared mode; and

(C) exhaust streams of units which vent to a common stack do not need to be analyzed separately.

(5) As an alternative to paragraph (1) of this subsection, an owner or operator may choose to comply with the CEMS requirements of 40 CFR Part 75 as follows:

(A) general operation requirements in Subpart B, §75.10(a)(2);

(B) certification procedures and test methods in Subpart C, §75.20(c) and §75.22;

(C) recordkeeping requirements of the monitoring plan in Subpart D, §75.53(a) - (c);

(D) appropriate specifications and test procedures in Appendix A, as follows:

(i) Section 1 (Installation and Measurement Location);

(ii) Section 2 (Equipment Specifications);

(iii) Section 3 (Performance Specifications);

(iv) Section 4 (Data Acquisition and Handling Systems);

(v) Section 5 (Calibration Gas);

(vi) Section 6 (Certification Tests and Procedures); and

(vii) meet either the relative accuracy requirement of 40 CFR Part 75 in percentage only, or the alternative relatively accuracy requirement of $\pm$ 2.0 ppmv from the reference method mean value; and

(E) appropriate quality assurance/quality control (QA/QC) procedures in Appendix B, as follows:

(i) Section 1 (Quality Assurance/Quality Control Program); and

(ii) Section 2 (Frequency of Testing).

(6) 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 (relating to Continuous Demonstration of Compliance).

(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 Part 75, Subpart E, except as provided in paragraphs (4) and (5) of this subsection.

(4) The owner or operator may vary from 40 CFR Part 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 Part 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 13.2 (pertaining to NO_x) in terms of the applicable standard (in ppmv, lb/MMBtu, or g/hp-hr). An alternative relative accuracy requirement of $\pm$ 2.0 ppmv from the reference method mean value is allowed;

(II) Performance Specification 3, subsection 13.2 (pertaining to O_2 or CO_2); and

(III) Performance Specification 4, subsection 13.2 (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 Part 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;

(IV) waivers from the statistical tests and default reference method standard deviation values for the F-test shall be allowed according to the "TNRCC PEMS Protocol Draft," May 16, 1994;

(V) the correlation analysis may only be temporarily waived following review of the waiver request submittal if:

(-a-) the process design is such that it is technically impossible to vary the process to result in a concentration change sufficient to allow a successful correlation analysis statistical test. Any waiver request must also be accompanied with documentation of the reference method measured concentration, and documentation that it is less than 50% of the emission limit or standard. The waiver is to be based on the measured value at the time of the waiver. Should a subsequent RATA effort identify a change in the reference method measured value by more than 30%, the statistical test must be repeated at the next RATA effort to verify the successful compliance with the correlation analysis statistical test requirement; or

(-b-) the data for a measured compound (e.g., NO_x, O_2) are determined to be autocorrelated according to the procedures of 40 CFR §75.41(b)(2). A complete analysis of autocorrelation with support information shall be submitted with the request for waiver. The statistical test shall be repeated at the next RATA effort to verify the successful compliance with the correlation analysis statistical test requirement; and

(VI) all requests for waivers shall be submitted to the Engineering Services Team, Office of Compliance and Enforcement for review. The manager of the Engineering Services Team shall approve or deny each waiver request;

(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 subparagraph (A)(i)(I) - (III) of this paragraph; 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% (or within $\pm$ 2.0 ppmv) 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 5.0 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) Engines not using NO_x CEMS or PEMS.

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

(B) Sample:

(i) on a biennial calendar basis; or

(ii) 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:

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

(-b-) an estimate of the date of the next required sampling.

(C) Engines used exclusively in emergency situations are not required to conduct the testing specified in subparagraph (B) of this paragraph.

(2) Engines using NO_x CEMS or PEMS. Engines which use a chemical reagent for reduction of NO_x shall monitor in accordance with subsection (c)(1)(E) of this section and shall comply with the applicable requirements of this section for CEMS and PEMS.

(h) Monitoring for stationary 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 ± 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; and

(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 exemption of §117.205(h)(2) or (9) or §117.203(a)(6)(D), (11), or (12) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001 shall be non-resettable.

(j) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.205(b)(6) or §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.

(1) 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 §117.205 or §117.206(a) or (b) of this title. 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.

(2) For units subject to the emission specifications of §117.206(c) of this title, the methods required in this section and §117.214 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) shall be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) to determine compliance. 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 RACT 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 under §117.215(b) of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

(m) Loss of NO_x RACT 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 shall notify the executive director within seven days if the Btu/yr or hour-per-year limit specified in §117.10 of this title (relating to Definitions), 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.

§117.214. Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration.

(a) Monitoring requirements.

(1) The owner or operator of units which are subject to the emission limits of §117.206(c) of this title (relating to Emission Specifications for Attainment Demonstrations) must comply with the following monitoring requirements.

(A) The nitrogen oxides (NO_x) monitoring requirements of §117.213(c), (e), and (f) of this title (relating to Continuous Demonstration of Compliance) apply.

(B) The carbon monoxide (CO) monitoring requirements of §117.213(d) of this title apply.

(C) The totalizing fuel flow meter requirements of §117.213(a) of this title apply.

(D) One of the following ammonia monitoring procedures shall be used to demonstrate compliance with the ammonia emission specification of §117.206(e)(2) of this title for gas-fired or liquid-fired units which inject urea or ammonia into the exhaust stream for NO_x control.

(i) Mass balance. Calculate ammonia emissions as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of the control device which injects urea or ammonia into the exhaust stream. The equation is: ammonia parts per million by volume (ppmv) at reference oxygen = $\{(a/b)\ (10^6) - (c)(d)\}$, where reference oxygen on a dry basis is 3.0% for boilers and process heaters, 0.0% for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents), 7.0% for boilers and industrial furnaces (BIF units) which were regulated as existing facilities by the EPA at 40 Code of Federal Regulations Part 266, Subpart H (as was in effect on June 9, 1993), wood-fired boilers, and incinerators, 15% for stationary gas turbines (including duct burners used in turbine exhaust ducts), gas-fired lean-burn engines, and lightweight aggregate kilns, and 3.0% for all other units; a = ammonia injection rate (in pounds per hour (lb/hr))/17 pound per pound-mole (lb/lb-mol); b = dry exhaust flow rate (lb/hr)/29 lb/lb-mol; c = change in measured NO_x concentration across catalyst (ppmv at reference oxygen); and d = correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia required by §117.211(a)(2) of this title (relating to Initial Demonstration of Compliance), using either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27.

(ii) Oxidation of ammonia to nitric oxide (NO). Convert ammonia to NO using molybdenum oxidizer and measure ammonia slip by difference using a NO analyzer. The NO analyzer shall be quality assured in accordance with manufacturer's specifications and with a quarterly cylinder gas audit with a ten ppmv reference sample of ammonia passed through the probe and confirming monitor response to within ± 2.0 ppmv.

(iii) Stain tubes. Measure ammonia using a sorbent or stain tube device specific for ammonia measurement in the 5.0 to 10.0 ppmv range. The frequency of sorbent/stain tube testing shall be daily for the first 60 days of operation, after which the frequency may be reduced to weekly testing if operating procedures have been developed to prevent excess amounts of ammonia from being introduced in the control device and when operation of the control device has been proven successful with regard to controlling ammonia slip. Daily sorbent or stain tube testing shall resume when the catalyst is within 30 days of its useful life expectancy. Every effort shall be made to take at least one weekly sample near the normal highest ammonia injection rate.

(iv) Other methods. Monitor ammonia using another continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) procedure subject to prior approval of the executive director. For purposes of this clause, the executive director is the Engineering Services Team, Office of Compliance and Enforcement.

(v) Records. The owner or operator shall maintain records which are sufficient to demonstrate compliance with the requirements of the appropriate clause of this subparagraph. For the sorbent or stain tube option, these records shall include the ammonia injection rate and NO_x stack emissions measured during each sorbent or stain tube test. The records shall be maintained for a period of at least five years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request.

(E) Installation of monitors shall be performed in accordance with the schedule specified in §117.520(c)(2) of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).

(2) The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.203(a)(6)(D), (11), or (12) of this title (relating to Exemptions) shall comply with the run time meter requirements of §117.213(i) of this title.

(b) Testing and operating requirements.

(1) The owner or operator of units which are subject to the emission limits of §117.206(c) of this title must test the units as specified in §117.211 of this title in accordance with the schedule specified in §117.520(c)(2) of this title.

(2) Each stationary internal combustion engine which is not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) 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 within two weeks after each occurrence of engine maintenance which may reasonably be expected to increase emissions, oxygen (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. Quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

(3) Each stationary internal combustion engine controlled with nonselective catalytic reduction (NSCR) 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.

(c) Emission allowances.

(1) The NO_x testing and monitoring data of subsections (a) and (b) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), shall be used to establish the emission factor for calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

(2) For units not operating with CEMS or PEMS, the following apply.

(A) Retesting as specified in subsection (b)(1) of this section is required within 60 days after any modification which could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in subsection (b)(1) of this section may be conducted at the discretion of the owner or operator after any modification which could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation (FGR), and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions from the date of the retesting forward. Until the date of the retesting, the previously determined emission factor shall be used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(D) All test reports must be submitted to the executive director for review and approval within 60 days after completion of the testing.

(3) The emission factor in paragraph (1) or (2) of this subsection is multiplied by the unit's level of activity to determine the unit's actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

§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 Use of Emissions Credits for Compliance);

(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 British thermal units per hour (MMBtu/hr);

(B) gas turbines with a megawatt (MW) rating greater than or equal to ten 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, 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) §117.206 of this title;

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

(C) §117.570 of this title (relating to Use of Emissions Credits for Compliance);

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

(E) Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program); and, where applicable, §117.210 of this title (relating to System Cap);

(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 central 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;

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

(6) for sources complying with §117.210 of this title, in addition to the requirements of paragraphs (1) - (5) of this subsection, the owner or operator shall submit:

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

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

(i) the average daily heat input H_i specified in §117.210(c)(1) and (2) of this title;

(ii) the maximum daily heat input H_{mi} specified in §117.210(c)(3) of this title;

(iii) the method of monitoring emissions; and

(iv) the method of providing substitute emissions data when the NO_x monitoring system is not providing valid data; and

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

(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.

§117.219. Notification, Recordkeeping, and Reporting Requirements.

(a) Startup and shutdown records. For units subject to the startup and/or shutdown exemptions allowed under §101.222 of this title (relating to Demonstrations), hourly records shall be made of startup 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 appropriate regional office and any local air pollution control agency having jurisdiction as follows:

(1) verbal notification of the date of any 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) relative accuracy test audit (RATA) 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 Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any testing conducted under §117.211 of this title and any CEMS or PEMS 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. For sources in the Houston/Galveston ozone nonattainment area in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), which are no longer subject to the emission limitations of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), the report is only a monitoring system report as specified in paragraph (3) of this subsection. 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 §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 stationary 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; and

(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; and

(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 gas-fired 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 semiannual 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; and

(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 subject to §117.213(a) of this title, records of annual fuel usage;

(2) 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;

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

(i) pound per million British thermal units (lb/MMBtu) heat input; and

(ii) pounds or tons per day; or

(C) daily emissions and fuel usage (or stack exhaust flow) for units subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title. Emissions must be recorded in units of:

(i) lb/MMBtu heat input or in the units of the applicable emission specification in §117.206(c) of this title; and

(ii) pounds or tons per day;

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

(A) emissions measurements required by:

(i) §117.208(d)(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;

(4) for each stationary 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;

(5) 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;

(6) for units claimed exempt from emission specifications using the exemption of §117.205(h)(2) or §117.203(a)(6)(D), (11), or (12) of this title (relating to Exemptions), 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. In addition, for each engine claimed exempt under §117.203(a)(6)(D) of this title, written records shall be maintained of the purpose of engine operation and, if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation;

(7) records of carbon monoxide measurements specified in §117.213(d)(2) of this title;

(8) 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;

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

(10) for each stationary diesel or dual-fuel engine in the Houston/Galveston ozone nonattainment area, records of each time the engine is operated for testing and maintenance, including:

(A) date(s) of operation;

(B) start and end times of operation;

(C) identification of the engine; and

(D) total hours of operation for each month and for the most recent 12 consecutive months.

§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 (CO) or ammonia limits of §117.206(e) of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.205 of this title or the CO or ammonia limits in §117.206(e) 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 controls to meet the nitrogen oxides emission specifications of §117.205 or §117.206 of this title, as applicable;

(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; and

(4) is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by EPA 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. For sources in the Beaumont/Port Arthur ozone nonattainment area complying with the lean-burn engine emission specifications in §117.205(e) of this title, the owner or operator may combine the source cap with sources complying with §117.205(a) - (d) of this title, using the 1997 - 1999 heat input baseline described earlier for the sources complying with §117.205(a) - (d) of this title.

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), 51.166, or 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 Part 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 in accordance with 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 in accordance with 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)

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

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 EPA'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 pounds 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 pounds 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 in accordance with §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 Code of Federal Regulations §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, Recordkeeping, 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.

(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; and

(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.

(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.

(l) This section shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(c)(2) of this title. For purposes of this paragraph, this means that the system cap of this section remains in effect until the emissions allocation for units under the Houston/Galveston mass emissions cap are equal to or less than the allocation that would be calculated using the source cap of this section.

SUBCHAPTER C: ACID MANUFACTURING
DIVISION 1: ADIPIC ACID MANUFACTURING
§§117.301, 117.309, 117.311, 117.313, 117.319, 117.321

STATUTORY AUTHORITY
The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§117.301. Applicability.

The provisions of this division (relating to Adipic Acid Manufacturing) shall apply only in the Beaumont/Port Arthur and Houston/Galveston ozone nonattainment areas. These provisions shall apply to each adipic acid production unit which is the affected facility.

§117.309. Control Plan Procedures.

Any person affected by this division (relating to Adipic Acid Manufacturing) shall submit a control plan to the executive director on the compliance status of all required emission controls and monitoring systems by April 1, 1994. The executive director shall approve the plan if it contains all the information specified in this section. Revisions to the control plan shall be submitted to the executive director for approval. The control plan shall provide a detailed description of the method to be followed to achieve compliance, specifying the anticipated dates by which the following steps will be taken:

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

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

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

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

§117.311. Initial Demonstration of Compliance.

(a) Compliance with the nitrogen oxides emission limits specified in §117.305 of this title (relating to Emission Specifications) shall be determined by the performance testing procedures specified in 40 Code of Federal Regulations (CFR) Part 60, Appendix A, Method 7, or an equivalent method approved by the executive director. Method 7A, 7B, 7C, or 7D may be used in place of Method 7. If Method 7C or 7D is used, the sampling time shall be at least one hour.

(b) Performance testing shall be conducted in accordance with the procedures specified in 40 CFR §60.8.

(c) Any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.313 of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational prior to conducting performance testing under subsections (a) and (b) of this section. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(d) Testing conducted before June 23, 1994 may be used to demonstrate compliance with the standard specified in §117.305 of this title if the owner or operator of an affected facility demonstrates to the executive director that the prior performance testing at least meets the requirements of subsections (a) - (c) of this section. The executive director reserves the right to request performance testing or CEMS or PEMS performance evaluation at any time.

§117.313. Continuous Demonstration of Compliance.

(a) The owner or operator of any facility subject to the provisions of this division (relating to Adipic Acid Manufacturing) shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides (NO_x) from the absorber.

(b) Any CEMS installed subject to subsection (a) of this section shall meet all requirements of 40 Code of Federal Regulations (CFR) §60.13; 40 CFR Part 60, Appendix B, Performance Specification 2; and quality assurance procedures of 40 CFR Part 60, Appendix F, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5.1.1.

(c) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this division may, with the approval of the executive director, elect to install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS). The required PEMS shall be used to measure NO_x emissions for each affected unit and shall be used to demonstrate continuous compliance with the emission limitations of §117.305 of this title (relating to Emission Specifications). Any PEMS shall meet the requirements of §117.319 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) and §117.213(f) of this title (relating to Continuous Demonstration of Compliance).

(d) The owner or operator of an affected facility shall establish a conversion factor for the purpose of converting monitoring data into units of the emission standard (in pounds NO_x per ton of acid produced) as specified in 40 CFR §60.73(b). NO_x emissions data recorded by the CEMS or PEMS shall be represented in terms of both parts per million by volume and pounds NO_x per ton of acid produced.

(e) After the initial demonstration of compliance required by §117.311 of this title (relating to Initial Demonstration of Compliance), compliance with §117.305 of this title shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission compliance method.

§117.319. Notification, Recordkeeping, and Reporting Requirements.

(a) The owner or operator of an affected facility shall submit notification to the executive director, as follows:

(1) verbal notification of the date of any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) performance evaluation conducted under §117.313(b) of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.311 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(b) The owner or operator of an affected facility shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any CEMS or PEMS performance evaluation conducted under §117.313 of this title, or any initial demonstration of compliance testing conducted under §117.311 of this title, within 60 days after completion of such evaluation or testing. For purposes of demonstrating compliance with §117.530 of this title (relating to Compliance Schedules for Nitric Acid and Adipic Acid Manufacturing Sources), such results shall be submitted no later than 30 days before the final compliance date specified in §117.530 of this title.

(c) The owner or operator of an affected facility shall report in writing to the executive director on a quarterly basis all periods of excess emissions, defined as any 24-hour period during which the average nitrogen oxides (NO_x) emissions (arithmetic average of 24 contiguous one-hour periods) exceed the emission limitation in §117.305 of this title (relating to Emission Specifications) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period;

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

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

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

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total operating time for the reporting period and the CEMS or PEMS downtime for the reporting period is less than 5.0% of the total operating time for the reporting period, only a summary report form (as outlined in the latest edition of the 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 PEMS downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(d) The owner or operator of an affected facility shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and daily production rates. Such records shall be kept for a period of at least 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.

§117.321. Alternative Case Specific Specifications.

Where a person can demonstrate that an affected unit cannot attain the requirements of §117.305 of this title (relating to Emission Specifications), as applicable, the executive director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.305 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.305 of this title. Any owner or operator affected by the decision of the executive director may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by EPA in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Adipic Acid Manufacturing).

DIVISION 2: NITRIC ACID MANUFACTURING - OZONE NONATTAINMENT AREAS
§§117.401, 117.409, 117.411, 117.413, 117.419, 117.421

STATUTORY AUTHORITY
The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§117.401. Applicability.

The provisions of this division (relating to Nitric Acid Manufacturing - Ozone Nonattainment Areas) shall apply only in the Beaumont/Port Arthur and Houston/Galveston ozone nonattainment areas. These provisions shall apply to each nitric acid production unit which is the affected facility.

§117.409. Control Plan Procedures.

Any person affected by this division (relating to Nitric Acid Manufacturing - Ozone Nonattainment Areas) shall submit a control plan to the executive director on the compliance status of all required emission controls and monitoring systems by April 1, 1994. The executive director shall approve the plan if it contains all the information specified in this section. Revisions to the control plan shall be submitted to the executive director for approval. The control plan shall provide a detailed description of the method to be followed to achieve compliance, specifying the anticipated dates by which the following steps will be taken:

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

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

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

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

§117.411. Initial Demonstration of Compliance.

(a) Compliance with the nitrogen oxides emission limits specified in §117.405 of this title (relating to Emission Specifications) shall be determined by the performance testing procedures specified in 40 Code of Federal Regulations (CFR) Part 60, Appendix A, Method 7, or an equivalent method approved by the executive director. Method 7A, 7B, 7C, or 7D may be used in place of Method 7. If Method 7C or 7D is used, the sampling time shall be at least one hour.

(b) Performance testing shall be conducted in accordance with the procedures specified in 40 CFR §60.8.

(c) Any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.413 of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational prior to conducting performance testing under subsections (a) and (b) of this section. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(d) Testing conducted before June 23, 1994 may be used to demonstrate compliance with the standard specified in §117.405 of this title if the owner or operator of an affected facility demonstrates to the executive director that the prior performance testing at least meets the requirements of subsections (a) - (c) of this section. The executive director reserves the right to request performance testing or CEMS or PEMS performance evaluation at any time.

§117.413. Continuous Demonstration of Compliance.

(a) The owner or operator of any facility subject to the provisions of this division (relating to Nitric Acid Manufacturing - Ozone Nonattainment Areas) shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides (NO_x) from the absorber.

(b) Any CEMS installed subject to subsection (a) of this section shall meet all requirements of 40 Code of Federal Regulations (CFR) §60.13; 40 CFR Part 60, Appendix B, Performance Specification 2; and quality assurance procedures of 40 CFR Part 60, Appendix F, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5.1.1.

(c) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this division may, with the approval of the executive director, elect to install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS). The required PEMS shall be used to measure NO_x emissions for each affected unit and shall be used to demonstrate continuous compliance with the emission limitations of §117.405 of this title (relating to Emission Specifications). Any PEMS shall meet the requirements of §117.419 of this title (relating to

Notification, Recordkeeping, and Reporting Requirements) and §117.213(f) of this title (relating to Continuous Demonstration of Compliance).

(d) The owner or operator of an affected facility shall establish a conversion factor for the purpose of converting monitoring data into units of the emission standard (in pounds NO_x per ton of acid produced, expressed as 100% nitric acid) as specified in 40 CFR §60.73(b). NO_x emissions data recorded by the CEMS or PEMS shall be represented in terms of both parts per million by volume and pounds NO_x per ton of acid produced, expressed as 100% nitric acid.

(e) After the initial demonstration of compliance required by §117.411 of this title (relating to Initial Demonstration of Compliance), compliance with §117.405 of this title (relating to Emission Specifications) shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission compliance method.

§117.419. Notification, Recordkeeping, and Reporting Requirements.

(a) The owner or operator of an affected facility shall submit notification to the executive director, as follows:

(1) verbal notification of the date of any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) performance evaluation conducted under §117.413(b) of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.411 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(b) The owner or operator of an affected facility shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any CEMS or PEMS performance evaluation conducted under §117.413 of this title, or any initial demonstration of compliance testing conducted under §117.411 of this title, within 60 days after completion of such evaluation or testing. For purposes of demonstrating compliance with §117.530 of this title (relating to Compliance Schedules for Nitric Acid and Adipic Acid Manufacturing Sources), such results shall be submitted no later than 30 days before the final compliance date specified in §117.530 of this title.

(c) The owner or operator of an affected facility shall report in writing to the executive director on a quarterly basis all periods of excess emissions, defined as any 24-hour period during which the average nitrogen oxides emissions (arithmetic average of 24 contiguous one-hour periods) as measured by a CEMS or PEMS exceed the emission limitation in §117.405 of this title (relating to Emission Specifications) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period;

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

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

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

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total operating time for the reporting period and the CEMS or PEMS downtime for the reporting period is less than 5.0% of the total operating time for the reporting period, only a summary report form (as outlined in the latest edition of the 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 PEMS downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(d) The owner or operator of an affected facility shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and daily production rates. Such records shall be kept for a period of at least five years and shall be made available upon request by authorized representatives of the executive director, EPA, or any local air pollution control agency having jurisdiction.

§117.421. Alternative Case Specific Specifications.

Where a person can demonstrate that an affected unit cannot attain the requirements of §117.405 of this title (relating to Emission Specifications), as applicable, the executive director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.405 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.405 of this title. Any owner or operator affected by the decision of the executive director may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by EPA in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Nitric Acid Manufacturing - Ozone Nonattainment Areas).

SUBCHAPTER D: SMALL COMBUSTION SOURCES
DIVISION 1: WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS
§§117.463, 117.465, 117.467

STATUTORY AUTHORITY
The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§117.463. Exemptions.

This division (relating to Water Heaters, Small Boilers, and Process Heaters) does not apply to:

(1) units using a fuel other than natural gas;

(2) units used in recreational vehicles;

(3) Type 0 units used exclusively to heat swimming pools and hot tubs;

(4) units manufactured in Texas for shipment and use outside of Texas; and

(5) units which do not comply with the nitrogen oxides (NO_x) limits specified in §117.465 of this title (relating to Emission Specifications) that are sold, supplied, or offered for sale in Texas, provided that the manufacturer or distributor can demonstrate that the units are intended for shipment and use outside of Texas, and that the manufacturer or distributor has taken reasonable prudent precautions to assure that the units are not distributed for sale in Texas. This paragraph does not apply to units that are sold, supplied, or offered for sale by any person to retail outlets in Texas.

§117.465. Emission Specifications.

Natural gas-fired Type 0, 1, and 2 units sold, distributed, installed, or offered for sale within the State of Texas shall meet the following limits for nitrogen oxides (NO_x, calculated as nitrogen dioxide (NO_2)).

(1) Type 0 units manufactured on or after July 1, 2002, but no later than December 31, 2004, shall not exceed:

(A) 40 nanograms per joule (ng/J) of heat output; or

(B) 55 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry.

(2) Type 0 units manufactured on or after January 1, 2005 shall not exceed:

(A) 10 ng/J of heat output; or

(B) 15 ppmv at 3.0% O_2, dry.

(3) Type 1 units manufactured on or after July 1, 2002 shall not exceed:

(A) 40 ng/J of heat output; or

(B) 55 ppmv at 3.0% O_2, dry.

(4) Type 2 units manufactured on or after July 1, 2002 shall not exceed:

(A) 30 ppmv at 3.0% O_2, dry; or

(B) 0.037 pound per million British thermal units (lb/MMBtu) of heat input.

§117.467. Certification Requirements.

(a) The manufacturer shall demonstrate that each model of Type 0, 1, and 2 unit subject to the requirements of §117.465 of this title (relating to Emission Specifications) has been tested in accordance with Test Method 7 (40 Code of Federal Regulations Part 60, Appendix A (June 11, 1986)), including 7A-E, and the South Coast Air Quality Management District (SCAQMD) Protocol: *Nitrogen Oxides Emissions Compliance Testing for Natural Gas-Fired Water Heaters and Small Boilers* (January 1998).

(b) The manufacturer may submit to the executive director an approved Bay Area Air Quality Management District or SCAQMD certification in lieu of conducting duplicative certification tests.

DIVISION 2: BOILERS, PROCESS HEATERS, AND STATIONARY ENGINES AND GAS TURBINES AT MINOR SOURCES
§§117.473, 117.475, 117.478, 117.479, 117.481

STATUTORY AUTHORITY
The amendments and new section are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments and new section are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§117.473. Exemptions.

(a) This division (relating to Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources) does not apply to the following, except as may be specified in §117.478(c) and §117.479(h) - (j) of this title (relating to Operating Requirements; and Monitoring, Recordkeeping, and Reporting Requirements):

(1) boilers and process heaters with a maximum rated capacity of 2.0 million British thermal units per hour (MMBtu/hr) or less;

(2) the following stationary engines:

(A) engines with a horsepower (hp) rating of less than 50 hp;

(B) engines used in research and testing;

(C) engines used for purposes of performance verification and testing;

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

(E) engines operated exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after October 1, 2001 is ineligible for this exemption. For the purposes of this subparagraph, the terms “modification” and “reconstruction” have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

(F) engines used in response to and during the existence of any officially declared disaster or state of emergency;

(G) engines used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals;

(H) diesel engines placed into service before October 1, 2001 which:

(i) operate less than 100 hours per year, based on a rolling 12-month average; and

(ii) have not been modified, reconstructed, or relocated on or after October 1, 2001. For the purposes of this clause, the terms “modification” and “reconstruction” have the meanings defined in §116.10 of this title and 40 CFR §60.15 (December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(I) new, modified, reconstructed, or relocated stationary diesel engines placed into service on or after October 1, 2001 which:

(i) operate less than 100 hours per year, based on a rolling 12-month average, in other than emergency situations; and

(ii) meet the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this subparagraph, the terms “modification” and “reconstruction” have the meanings defined in §116.10 of this title and 40 CFR §60.15 (December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(3) stationary gas turbines rated at less than 1.0 megawatt with initial start of operation on or before October 1, 2001.

(b) At any stationary source of nitrogen oxides (NO_x) which is not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the following are exempt from the requirements of this division, except for the totalizing fuel flow requirements of §117.479(a), (d), and (g)(1) of this title:

(1) any boiler or process heater with a maximum rated capacity greater than 2.0 MMBtu/hr and less than 5.0 MMBtu/hr that has an annual heat input less than or equal to 1.8 (10^9) Btu per calendar year; and

(2) any boiler or process heater with a maximum rated capacity equal to or greater than 5.0 MMBtu/hr that has an annual heat input less than or equal to 9.0 (10^9) Btu per calendar year.

§117.475. Emission Specifications.

(a) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the nitrogen oxides (NO_x) emission rate values used to determine allocations for Chapter 101, Subchapter H, Division 3 of this title shall be the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in subsection (c) of this section. The averaging time shall be as specified in Chapter 101, Subchapter H, Division 3 of this title.

(b) For sources which are not subject to Chapter 101, Subchapter H, Division 3 of this title, NO_x emissions are limited to the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in subsection (c) of this section. The averaging time shall be as follows:

(1) if the unit is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.479(c) of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements), 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 pound NO_x per million British thermal units (lb/MMBtu); or

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.479(c) of this title, a block one-hour average, in the units of the applicable standard.

(c) The following NO_x emission specifications shall be used in conjunction with subsection (a) of this section to determine allocations for Chapter 101, Subchapter H, Division 3 of this title, or in conjunction with subsection (b) of this section to establish unit-by-unit emission specifications, as appropriate:

(1) from boilers and process heaters:

(A) gas-fired, 0.036 lb/MMBtu heat input (or alternatively, 30 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry basis); and

(B) liquid-fired, 0.072 lb/MMBtu heat input (or alternatively, 60 ppmv at 3.0% O_2, dry basis);

(2) from stationary, gas-fired, reciprocating internal combustion engines:

(A) fired on landfill gas, 0.60 gram per horsepower-hour (g/hp-hr); and

(B) all others, 0.50 g/hp-hr;

(3) from stationary, dual-fuel, reciprocating internal combustion engines, 5.83 g/hp-hr;

(4) from stationary, diesel, reciprocating internal combustion engines:

(A) placed into service before October 1, 2001 which have not been modified, reconstructed, or relocated on or after October 1, 2001, the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. For the purposes of this paragraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account; and

(B) for engines not subject to subparagraph (A) of this paragraph:

(i) with a horsepower rating of 50 hp or greater, but less than 100 hp, which are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2003, 6.9 g/hp-hr;

(II) on or after October 1, 2003, but before October 1, 2007, 5.0 g/hp-hr; and

(III) on or after October 1, 2007, 3.3 g/hp-hr;

(ii) with a horsepower rating of 100 hp or greater, but less than 175 hp, which are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2002, 6.9 g/hp-hr;

(II) on or after October 1, 2002, but before October 1, 2006, 4.5 g/hp-hr; and

(III) on or after October 1, 2006, 2.8 g/hp-hr;

(iii) with a horsepower rating of 175 hp or greater, but less than 300 hp, which are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2002, 6.9 g/hp-hr;

(II) on or after October 1, 2002, but before October 1, 2005, 4.5 g/hp-hr; and

(III) on or after October 1, 2005, 2.8 g/hp-hr;

(iv) with a horsepower rating of 300 hp or greater, but less than 600 hp, which are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2005, 4.5 g/hp-hr; and

(II) on or after October 1, 2005, 2.8 g/hp-hr;

(v) with a horsepower rating of 600 hp or greater, but less than or equal to 750 hp, which are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2005, 4.5 g/hp-hr; and

(II) on or after October 1, 2005, 2.8 g/hp-hr; and

(vi) with a horsepower rating of 750 hp or greater which are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2005, 6.9 g/hp-hr; and

(II) on or after October 1, 2005, 4.5 g/hp-hr;

(5) from stationary gas turbines (including duct burners), 0.15 lb/MMBtu; and

(6) as an alternative to the emission specifications in paragraphs (1) - (5) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input. For units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor shall be used to determine whether the unit is eligible for the emission specification of this paragraph. For units placed into service after January 1, 1997, the annual capacity factor shall be calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph, using the same two consecutive years chosen for the activity level baseline. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions).

(d) The maximum rated capacity used to determine the applicability of the emission specifications in subsection (c) of this section shall be:

(1) the greater of the following:

(A) the maximum rated capacity as of December 31, 2000; or

(B) the maximum rated capacity after December 31, 2000; or

(2) alternatively, the maximum rated capacity authorized by a permit issued under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, provided that the maximum rated capacity authorized by the permit issued on or after January 2, 2001 is no less than the maximum rated capacity represented in the permit application as of January 2, 2001.

(e) A unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, a unit that is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, shall be classified as a stationary gas-fired engine for the purposes of this chapter.

(f) Changes after December 31, 2000 to a unit subject to an emission specification in subsection (c) of this section (ESAD unit) which result in increased NO_x emissions from a unit not subject to an emission specification in subsection (c) of this section (non-ESAD unit), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if:

(1) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS which meets the requirements of §117.479(c) of this title, or through stack testing which meets the requirements of §117.479(e) of this title; and

(2) either of the following conditions is met:

(A) for sources which are subject to Chapter 101, Subchapter H, Division 3 of this title, a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made as specified in §101.354 of this title (relating to Allowance Deductions); or

(B) for sources which are not subject to Chapter 101, Subchapter H, Division 3 of this title, emission credits equal to the increase in NO_x emissions at the non-ESAD unit are obtained and used in accordance with §117.570 of this title (relating to Use of Emissions Credits for Compliance).

(g) A source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of this chapter. A source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of this chapter.

(h) The availability under subsection (c)(6) of this section of an emission specification for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. Reduced operation after December 31, 2000 cannot be used to qualify for a more lenient emission specification under subsection (c)(6) of this section than would otherwise apply to the unit.

(i) No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (c) of this section, emissions in excess of the following, except as provided in §117.481 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO), 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines:

(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) for units which inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions of ten ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts) and gas-fired lean-burn engines; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

§117.478. Operating Requirements.

(a) The owner or operator shall operate any unit subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) in compliance with those limitations.

(b) All units subject to the emission limitations of §117.475 of this title shall be operated so as to minimize nitrogen oxides (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 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.

(4) 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.

(5) 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 within two weeks after each occurrence of engine maintenance which may reasonably be expected to increase emissions, O_2 sensor replacement, 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. Quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

(c) No person shall start or operate any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon, except:

(1) for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours;

(2) to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair; or

(3) firewater pumps for emergency response training conducted in the months of April through October.

§117.479. Monitoring, Recordkeeping, and Reporting Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of each unit subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) or claimed exempt under §117.473(b) of this title (relating to Exemptions) 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.

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

(b) Oxygen (O_2) monitors. If the owner or operator installs an O_2 monitor, the criteria in §117.213(e) of this title (relating to Continuous Demonstration of Compliance) should be considered the appropriate guidance for the location and calibration of the monitor.

(c) NO_x monitors. If the owner or operator installs a CEMS or predictive emissions monitoring system (PEMS), it shall meet the requirements of §117.213(e) or (f) of this title.

(d) Monitor installation schedule. Installation of monitors shall be performed in accordance with the schedule specified in §117.534 of this title (relating to Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources).

(e) Testing requirements. The owner or operator of any unit subject to the emission limitations of §117.475 of this title shall comply with the following testing requirements.

(1) Each unit shall be tested for NO_x, carbon monoxide (CO), and O_2 emissions.

(2) One of the ammonia monitoring procedures specified in §117.214(a)(1)(D) of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) shall be used to demonstrate compliance with the ammonia emission specification of §117.475(i)(2) of this title for units which inject urea or ammonia into the exhaust stream for NO_x control.

(3) All testing shall be conducted 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:

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

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

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

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

(E) 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

(F) 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:

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

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

(4) Test results shall be reported in the units of the applicable emission limits and averaging periods. If compliance testing is based on 40 CFR 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).

(5) For units equipped with CEMS or PEMS, the CEMS or PEMS shall be installed and operational before testing under this subsection. 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.

(6) Initial compliance with the emission specifications of §117.475 of this title for units operating with CEMS or PEMS shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS.

(7) For units not operating with CEMS or PEMS, the following apply.

(A) Retesting as specified in paragraphs (1) - (4) of this subsection is required within 60 days after any modification which could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in paragraphs (1) - (4) of this subsection may be conducted at the discretion of the owner or operator after any modification which could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation (FGR), and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions from the date of the retesting forward. Until the date of the retesting, the previously determined emission factor shall be used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

(8) Testing shall be performed in accordance with the schedule specified in §117.534 of this title.

(9) All test reports must be submitted to the executive director for review and approval within 60 days after completion of the testing.

(f) Emission allowances.

(1) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title, the NO_x testing and monitoring data of subsections (a) - (e) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), shall be used to establish the emission factor calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(2) The emission factor in subsection (e)(7) of this section or paragraph (1) of this subsection is multiplied by the unit's level of activity to determine the unit's actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(g) Recordkeeping. The owner or operator of a unit subject to the emission limitations of §117.475 of this title or claimed exempt under §117.473(b) of this title 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) records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with subsection (c) of this section, 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;

(3) for each stationary internal combustion engine subject to the emission limitations of §117.475 of this title, records of:

(A) emissions measurements required by §117.478(b)(5) of this title (relating to Operating Requirements); and

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

(4) records of CO measurements specified in §117.478(b)(5) of this title;

(5) 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; and

(6) records of the results of performance testing, including the testing conducted in accordance with subsection (e) of this section.

(h) Records for exempt engines. Written records of the number of hours of operation for each day's operation shall be made for each engine claimed exempt under §117.473(a)(2)(E), (H), or (I) of this title (relating to Exemptions) or §117.478(b)(5) of this title. In addition, for each engine claimed exempt under §117.473(a)(2)(E) of this title, written records shall be maintained of the purpose of engine operation and, if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation. The records shall be maintained for at least five years and shall be made available upon request to representatives of the executive director, EPA, or any local air pollution control agency having jurisdiction.

(i) Run time meters. The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.473(a)(2)(E), (H), or (I) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001 shall be non-resettable.

(j) Records of operation for testing and maintenance. The owner or operator of each stationary diesel or dual-fuel engine shall maintain the following records for at least five years and make them available upon request by authorized representatives of the executive director, EPA, or local air pollution control agencies having jurisdiction:

(1) date(s) of operation;

(2) start and end times of operation;

(3) identification of the engine; and

(4) total hours of operation for each month and for the most recent 12 consecutive months.

§117.481. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the carbon monoxide (CO) or ammonia limits of §117.475(i) of this title (relating to Emission Specifications), the executive director may approve emission specifications different from the CO or ammonia limits in §117.475(i) 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 controls to meet the nitrogen oxides (NO_x) emission specifications of §117.475 of this title;

(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; and

(4) is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director’s Decision) apply.

SUBCHAPTER E: ADMINISTRATIVE PROVISIONS
§§117.510, 117.512, 117.520, 117.534

STATUTORY AUTHORITY

The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state’s air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

§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 system (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 under 40 Code of Federal Regulations (CFR) Part 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 Part 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 May 11, 2000; 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 Use of Emissions Credits for Compliance);

(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) May 1, 2003, install CEMS or PEMS on previously exempt units and conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title;

(D) 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;

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

(F) 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 in §117.106(a) of this title; and

(G) 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 in §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;

(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.

(A) The owner or operator shall comply with the requirements of §117.106(b) of this title as soon as practicable, but no later than:

(i) 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 May 11, 2000; 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:

(-a-) §117.108 of this title; or

(-b-) §117.570 of this title;

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

(I) identification of enforceable emission limits which satisfy clause (i) of this subparagraph;

(II) the information specified in §117.116 of this title to comply with clause (i) of this subparagraph; and

(III) any other revisions to the source's final control plan as a result of complying with clause (i) of this subparagraph;

(iii) May 1, 2003, install CEMS or PEMS on previously exempt units and conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title;

(iv) 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 clause (i) of this subparagraph;

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

(vi) 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 in §117.106(b) of this title; and

(vii) 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 in §117.106(b) of this title.

(B) The requirements of subparagraph (A)(i) of this paragraph may be modified as follows. Boilers which are to be retired and decommissioned before May 1, 2005 are not required to install controls by May 1, 2003 if the following conditions are met:

(i) the boiler is designated by the Public Utility Commission of Texas to be necessary to operate for reliability of the electric system;

(ii) the owner provides the executive director an enforceable written commitment by May 1, 2003 to retire and permanently decommission the boiler by May 1, 2005;

(iii) the utility boiler is retired and permanently decommissioned by May 1, 2005; and

(iv) by May 1, 2003, all remaining boilers (those not designated for retirement and decommissioning as specified in clauses (i) - (iii) of this subparagraph) within the electric utility system are controlled to achieve at least two-thirds of the NO_x emission reductions from units not being retired and decommissioned.

(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 the dates specified in this subsection.

(1) Reasonably available control technology. 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 CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title according to the following schedules:

(i) for equipment and software required under 40 CFR Part 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 Part 75, no later than November 15, 1999;

(B) install all 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; 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, no later than November 15, 1999.

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.114 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) of this title as soon as practicable, but no later than:

(i) March 31, 2005, install any totalizing fuel flow meters and emissions monitors required by §117.114 of this title, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.114 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit. However, an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005; and

(ii) 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(I) stack tests conducted in accordance with §117.111 of this title; or, as applicable,

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

(B) The owner or operator shall:

(i) no later than June 30, 2001, submit to the executive director the certification of level of activity, H_i, specified in §117.108 of this title for electric generating facilities (EGFs) which were in operation as of January 1, 1997;

(ii) no later than 60 days after the second consecutive third quarter of actual level of activity level data are available, submit to the executive director the certification of activity level, H_i, specified in §117.108 of this title for EGFs which were not in operation prior to January 1, 1997; and

(iii) comply with the requirements of §117.108 of this title as soon as practicable, but no later than:

(I) March 31, 2003, demonstrate that at least 50% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title; and

(II) March 31, 2004, submit the information specified in §117.116 of this title;

(III) March 31, 2004, demonstrate compliance with the system cap limit of §117.108 of this title.

(C) For any unit subject to §117.106(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under subparagraph (A)(ii) of this paragraph, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

(i) stack tests conducted in accordance with §117.111 of this title; or, as applicable,

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

(D) The owner or operator shall comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) as soon as practicable, but no later than the appropriate dates specified in that program.

§117.512. Compliance Schedule for Utility Electric Generation in East and Central Texas.

The owner or operator of each utility electric power boiler or stationary gas turbine located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, and Wharton Counties shall comply with the requirements of Subchapter B, Division 2 of this chapter (relating to Utility Electric Generation in East and Central Texas) as soon as practicable, but no later than the following dates:

(1) except as provided in subparagraph (C) of this paragraph, May 1, 2003 for units owned by utilities which are subject to the cost-recovery provisions of Texas Utilities Code, §39.263(b):

(A) the owner or operator shall use the period of May 1, 2003 through April 30, 2004 for the initial annual compliance period. Compliance for each subsequent annual period is on a calendar year basis. For example, the second annual compliance period is January 1, 2004 through December 31, 2004;

(B) the updated final control plan required by §117.145 of this title (relating to Final Control Plan Procedures) shall be submitted by May 31, 2004, and by January 31, 2005; and

(C) the owner or operator shall comply with the ammonia limit of §117.135(2) of this title (relating to Emission Specifications) by May 1, 2005; and

(2) May 1, 2005 for all other units:

(A) the owner or operator shall use the period of May 1, 2005 through April 30, 2006 for the initial annual compliance period. Compliance for each subsequent annual period is on a calendar year basis. For example, the second annual compliance period is January 1, 2006 through December 31, 2006; and

(B) the updated final control plan required by §117.145 of this title shall be submitted by May 31, 2006, and by January 31, 2007.

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

(a) The owner or operator of each industrial, commercial, and institutional 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) of this subsection (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 a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (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) 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 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.

(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 May 11, 2000; 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 Use of Emissions Credits for Compliance);

(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) and (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 in §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 in §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 in §117.206(a) of this title.

(b) The owner or operator of each industrial, commercial, and institutional 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) 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) 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 industrial, commercial, and institutional 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 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) of this subsection (relating to emission specifications for attainment demonstration), by November 15, 1999 (final compliance date); and

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

(i) 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;

(ii) 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

(iii) for major sources of NO_x subject to either subparagraph (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;

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

(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 §117.211 of this title; 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 §117.213 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:

(-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;

(iii) a final control plan for compliance in accordance with §117.215 of this title, no later than November 15, 1999; and

(iv) 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.

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.214 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) as soon as practicable, but no later than:

(i) March 31, 2005, install any totalizing fuel flow meters, run time meters, and emissions monitors required by §117.214 of this title, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.214 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit. However, an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005; and

(ii) 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(I) stack tests conducted in accordance with §117.211 of this title. For a stack test conducted before March 31, 2005 on a unit not equipped with CEMS or PEMS for which CEMS or PEMS must be installed no later than March 31, 2005, the requirements of §117.211(c) of this title do not apply; or, as applicable,

(II) 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. The applicable CEMS or PEMS performance evaluation and quality assurance procedures must be submitted no later than March 31, 2005, except that if the unit is shut down as of March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures must be submitted within 60 days after startup of the unit after March 31, 2005.

(B) The owner or operator of each electric generating facility (EGF) shall:

(i) no later than June 30, 2001, submit to the executive director the certification of level of activity, H_i, specified in §117.210 of this title (relating to System Cap) for EGFs which were in operation as of January 1, 1997;

(ii) no later than 60 days after the second consecutive third quarter of actual level of activity level data are available, submit to the executive director the certification of activity level, H_i, specified in §117.210 of this title for EGFs which were not in operation prior to January 1, 1997; and

(iii) comply with the requirements of §117.210 of this title as soon as practicable, but no later than March 31, 2007.

(C) For any units subject to §117.206(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph

(2)(A) of this subsection, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

(i) stack tests conducted in accordance with §117.211 of this title; or, as applicable,

(ii) 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.

(D) The owner or operator shall comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) as soon as practicable, but no later than the appropriate dates specified in that program.

(E) For diesel and dual-fuel engines, the owner or operator shall comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002.

(F) The owner or operator shall comply with all other requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than March 31, 2005.

§117.534. Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources.

The owner or operator of each stationary source of nitrogen oxides (NO_x) in the Houston/Galveston ozone nonattainment area which is not a major source of NO_x shall comply with the requirements of Subchapter D, Division 2 of this chapter (relating to Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources) as follows.

(1) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the owner or operator shall:

(A) install any totalizing fuel flow meters and run time meters required by §117.479 of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements) and begin keeping records of fuel usage no later than March 31, 2005, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.479 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit. However, an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005;

(B) no later than 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(i) stack tests conducted in accordance with §117.479 of this title. For a stack test conducted before March 31, 2005 on a unit not equipped with CEMS or PEMS for which

CEMS or PEMS must be installed no later than March 31, 2005, the requirements of §117.479(e)(6) of this title do not apply; or, as applicable,

(ii) the applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (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 (relating to Continuous Demonstration of Compliance). The applicable CEMS or PEMS performance evaluation and quality assurance procedures must be submitted no later than March 31, 2005, except that if the unit is shut down as of March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures must be submitted within 60 days after startup of the unit after March 31, 2005;

(C) no later than March 31, 2005, for any units subject to §117.475 of this title (relating to Emission Specifications) for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (1)(B) of this section, submit to the executive director the results of:

(i) stack tests conducted in accordance with §117.479 of this title; or, as applicable,

(ii) 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;

(D) comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title as soon as practicable, but no later than the appropriate dates specified in that program;

(E) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002; and

(F) comply with all other requirements of Subchapter D, Division 2 of this chapter as soon as practicable, but no later than March 31, 2005.

(2) For sources which are not subject to Chapter 101, Subchapter H, Division 3 of this title, the owner or operator shall:

(A) install any totalizing fuel flow meters and run time meters required by §117.479 of this title and begin keeping records of fuel usage no later than March 31, 2005, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.479 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit. However, an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005;

(B) no later than 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(i) stack tests conducted in accordance with §117.479 of this title. For a stack test conducted before March 31, 2005 on a unit not equipped with CEMS or PEMS for which CEMS or PEMS must be installed no later than March 31, 2005, the requirements of §117.479(e)(6) of this title do not apply; or, as applicable,

(ii) 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. The applicable CEMS or PEMS performance evaluation and quality assurance procedures must be submitted no later than March 31, 2005, except that if the unit is shut down as of March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures must be submitted within 60 days after startup of the unit after March 31, 2005;

(C) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002; and

(D) comply with all other requirements of Subchapter D, Division 2 of this chapter as soon as practicable, but no later than March 31, 2005.

SUBCHAPTER E: ADMINISTRATIVE PROVISIONS
§117.540, §117.560

STATUTORY AUTHORITY

The repeals are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under THSC, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The repeals are also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

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

§117.560. Rescission.