Final Report

Survey of Emissions, Emission Regulations, and Control Technology Cost Effectiveness for Large Industrial NOx Sources in Eastern Texas and Eight Surrounding States HARC Project H36

Prepared for

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ACROYNMS

BACT	Best Available Control Technology
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
COPNG	Crude Oil Petroleum and Natural Gas
DLNC	Dry Low NO_x Combustors
EGU	Electric Generating Unit
FCC	Fluid Catalytic Cracking
HARC	Houston Advanced Research Center
IC	Internal Combustion
LAER	Lowest Achievable Emission Requirements
LNB	Low NO_x Burner
MACT	Maximum Achievable Control Technology
NAA	Non-attainment Area
NBP	NO_x Budget Trading Program
NEI	National Emissions Inventory
NGL	Natural Gas Liquids
NNAA	Near-non-attainment Area
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
ppb	Parts per billion
PSD	Prevention of Significant Deterioration
RACT	Reasonably Achievable Control Technology
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	Selective Non-catalytic Reduction
SNPRM	Supplemental Notice of Proposed Rule-Making
TCEQ	Texas Commission on Environmental Quality
tpd	Tons per day

EXECUTIVE SUMMARY

In a previous study carried out for the Houston Advanced Research Center (HARC Project H-35), it was found that NOx sources in seven states, Texas, and the Gulf of Mexico exceeded EPA's initial screening criteria as potentially significant contributors to 8-hour ozone levels above 85 ppb in one or more non-attainment areas (NAAs) in Texas. The most significant out-of-state impacts were from Louisiana and Arkansas with additional potentially significant contributions from Alabama, Kentucky, Mississippi, Oklahoma and Tennessee. Extending the transport analysis to include near – NAAs at an ozone threshold of 75 ppb resulted in the addition of an eighth state, (Missouri) to the list of potentially significant contributing states.

Based on the findings of the H-35 study, and the impending 8-hour ozone State Implementation Plan (SIP) requirements in several major areas of Texas, this study looked more specifically at regulations, emissions, control strategies, and specific sources in the eight states identified in H-35 to determine whether additional controls might be considered to improve air quality in those states as well as assist Texas in attaining the health standards in a more cost-effective and efficient manner.

A technical assessment of emissions and stringency of regulation in the eight "upwind" states was prepared along with a comparison of these regulations to those adopted in Texas. Information was gathered on NOx emissions, major point sources of NOx, control methods, and applicable regulations in the eight states. Based on existing published cost information for control equipment, a cost comparison of appropriate control technologies was made. Also included was a review of pending interstate regulations and legislation that might impact the study area, primarily the Clean Air Interstate Rule (CAIR) and the Clear Skies proposed legislation. Finally, additional areas for study were identified should Texas decide to pursue these findings with greater detail and documentation. By comparing emission levels between the current National Emission Inventory (NEI) and the CAIR-projected 2010 emissions on a point source basis, specific point sources with potential for further examination for additional NO_x controls were identified.

Major individual point sources and Standard Industrial Classification (SIC) categories that proportionally contribute significantly to statewide NOx emissions were examined. Limited resources did not allow for examination of specific sources and their emission unit controls in detail ("bottom-up approach"), but any readily available information on current controls, such as Selective Catalytic Retrofits (SCR) on Electrical Generating Units (EGUs) are included.

The end product of this study is a presentation each state's current control limits by equipment type, expected emission reductions, and cost-effectiveness as compared with regulation of similar equipment in Texas. Texas rules are subdivided into two categories – "typical" regulatory requirements for areas such as the Tyler-Longview-Marshall near nonattainment area (NNAA) and for the most stringent rules, generally those in the Houston-Galveston NAA.

Taken together, results of this and the H-35 study, while subject to future refinement and a number of key caveats described in the report, provide support for the conclusion that opportunities exist for additional NO_x emission reductions in a number of upwind states which would result in air quality improvements in the ozone nonattainment and near-nonattainment areas of eastern Texas. Additional, more detailed analyses will be needed to pinpoint the specific NO_x sources representing the best opportunities for emission reductions and to quantify the expected air quality benefits and costs associated with any such reductions.

This study involved considerable research and analysis of various data sources and provides a good screening of the various emission trends, specific point sources, current and future regulations and control strategies, and potential cost-effectiveness of additional control measures. While the limited resources for this study did not provide the source-by-source analysis necessary to pinpoint specific emission reductions that might occur from applying Texas-level controls to each of the eight states in our study area, we believe that sufficient information has been developed here to conclude that significant emission reductions can be achieved in at least some neighboring states.

While this report indicates important potential for emissions reductions of NOx, it also is intended to serve as a point of departure for a further, more exhaustive assessment, and not as a comprehensive feasibility assessment for specific sources or source categories. If the state of Texas should decide, based on the screening analysis in this report and other important policy considerations, to pursue a specific strategy to "encourage" adjacent states to tighten their regulations as a part of a region-wide effort to lower ozone levels, a more specific and focused study will need to be conducted. Such a study would build upon selected findings from this report. Several areas of necessary research in this regard are recommended.

1. INTRODUCTION

Background

In a previous study for the Houston Advanced Research Center (HARC), ENVIRON conducted a modeling analysis to identify states with precursor emissions that significantly contribute to the occurrence of high ozone levels in eastern Texas due to transport of ozone and ozone precursors into Texas. This work was performed under HARC project H35.2004 and is referred to hereafter as the H-35 study[1]. Preliminary findings from the H-35 study indicate that seven states, Texas, and sources in the Gulf of Mexico exceeded EPA's initial screening criteria as potentially significant contributors to 8-hour ozone levels (>85 ppb) in one or more non-attainment areas (NAAs) in Texas. The most significant out-of-state impacts were from Louisiana and Arkansas with additional potentially significant contributions from Alabama, Kentucky, Mississippi, Oklahoma and Tennessee. Extending the transport analysis to include near – NAAs at an ozone threshold of 75ppb resulted in the addition of an eighth state, (Missouri) to the list of potentially significant contributing states.

Based on the findings of the H35 study, and the impending 8-hour ozone State Implementation Plan (SIP) requirements in several major areas of Texas, ENVIRON was asked to look more specifically at regulations, emissions, control strategies, and specific sources in these eight states to determine whether additional controls might be considered to improve air quality in those states as well as assist Texas in attaining the health standards in a more cost-effective and efficient manner.

Description of the Project

Our study consisted of a technical assessment of emissions and stringency of regulation in the eight "upwind" states identified in the H-35 study and a comparison of these regulations to those adopted in Texas. Information was gathered on NOx emissions, major point sources of NOx, control methods and applicable regulations in the eight states. Based on existing published cost information for control equipment, a cost comparison of appropriate control technologies was made. Also included was a review of pending interstate regulations and legislation that might impact the study area, primarily the Clean Air Interstate Rule (CAIR) and the Clear Skies proposed legislation. Finally, additional areas for study were identified should Texas decided to pursue these findings with greater detail and documentation.

Our study was conducted with a "top-down" approach, looking at major point sources and Standard Industrial Classification (SIC) categories that proportionally contribute significantly to the statewide NOx emissions. Limited resources did not allow us to examine specific sources and their emission unit controls ("bottom-up approach"), but we did include any information readily available on current controls, such as Selective Catalytic Retrofits (SCR) on Electrical Generating Units (EGUs). We examined state regulations in each of these categories. Finally, by comparing emission levels between the current National Emission Inventory (NEI) and the

[1] See reference to ENVIRON, 2004 in the Bibliography (Section 9). The Bibliography lists all resource material used to conduct this study.

CAIR-projected 2010 emissions on a point source basis, we were able to identify specific point sources that have potential for further examination for additional NO_x controls.

The end product of our study is a table comparing each state's current control limits by equipment type, expected emission reductions, and cost-effectiveness with regulation of that equipment in Texas. Texas rules are subdivided into two categories – "typical" regulatory requirements for areas such as the Tyler-Longview-Marshall near nonattainment area (NNAA) and for the most stringent rules, generally those in the Houston-Galveston NAA.

While this report indicates important potential for emissions reductions of NOx, it also is intended to serve as a point of departure for a further, more exhaustive assessment, and not as a comprehensive feasibility assessment for specific sources or source categories.

Organization of the Report

This report is divided into nine sections as follows:

Section 2 provides a more detailed description of the approach ENVIRON took in the study and any study limitations due to resources or data deficiencies. The approach was provided in advance of the detailed data gathering and received concurrence by HARC and The Texas Commission on Environmental Quality (TCEQ).

Section 3 describes the proposed CAIR and competing activities to amend the Clean Air Act (CAA). Final outcome of both of these activities will occur after the completion of this study, and may be an area for future analysis once it is clear which approach will be applied to the study area and Texas.

Section 4 is an examination of NOx emission reduction potential for each of the eight study area states. This section includes information on major NOx point sources, including their location, emissions in 2001 and 2010, peak summer NOx day and seasonal emissions (for EGU sources only), control equipment (when available), and current state and local air pollution regulations upon the priority sources.

Section 5 provides a brief overview of regulations in eastern and central Texas, relying on earlier work performed by ENVIRON for TCEQ and ETCOG in 2002 and more recent updates to the NAA SIPs in the Dallas-Fort Worth and Houston-Galveston areas.

Section 6 includes detailed tables and analysis of control technology required to meet the existing state regulations, what additional control technology may be available, and published cost-effectiveness data.

Section 7provides a summary of our key findings on comparative regulatory requirements in the eight study states with those of Texas, both for NAAs and more "typical" attainment/NNAAs of eastern Texas.

Section 8 summarizes the findings of the study and makes recommendations for future *technical* studies.

A bibliography listing source material used for this study is provided in Section 9. A set of seven appendices supports the various findings and methodologies employed in the body of the report. They also provide supplemental data on sources and emissions so that the readers have a broader picture of the air quality situation in the eight study area states as well as in Texas.

2. APPROACH AND LIMITATIONS

Approach

Preliminary modeling conducted by ENVIRON in HARC-35 showed that emission sources in a number of states and the offshore Gulf Area make significant contributions to one or more ozone episodes in Eastern Texas. The states, in alphabetical order, are Arkansas, Alabama, Kentucky, Louisiana, Mississippi, Missouri, Oklahoma, and Tennessee. In order to maximize the value of the study, given limited resources, the first step was to establish priorities for further analysis. We reviewed the NEI 1999 Facility Emissions inventory for each state to identify the largest NOx emissions categories by SIC code.

Since electrical generating facilities (EGUs) were a priority category in each state, and many EGUs are subject to control between 1999 and 2010, we decided to treat them in more detail than non-EGU categories. The EGUs are listed individually in each state along with information on 2001 and 2010 emissions, current and planned control equipment, and other relevant information. The EGUs included vary in size cutoff from state to state, based on the impact of that state upon episodes in Texas SIP areas as determined in the H-35 Study.

For non-EGU SIC categories, we established a cutoff of 6% of the emissions from point source 1999 NOx inventory and analyzed only those SIC categories with emissions above these cutoffs. The number of non-EGU SIC categories that exceeded the 6% cutoff varied from state to state, from four in Louisiana to zero in Missouri and Kentucky. Using the 6% cutoff criteria, we estimated that we captured 75% of all NOx point source emissions in the three states immediately adjacent to eastern Texas and 82% of the emissions in the other five study area states. A more detailed explanation of the methodology for setting priorities is included in Appendix D. The table in Appendix D contains the priority-setting findings. Appendix G lists the non-EGU point sources, using the cutoff size criteria outlined above. Data for the non-EGU point sources includes facility name, location, and CAIR-projected 2010 NOx emissions.

Once priorities were established, we took the following steps:

1. Provided a brief introduction to each state that describes preliminary modeling results, important emissions source categories, and the state's attainment status and other regulatory drivers that affect control requirements.

2. Developed a table for major EGUs for each state listing all relevant information. Data in the table was then analyzed for potential addition source controls, based on existing control equipment and projected installation of new control equipment in the 1999 to 2010 period.

3. Described the high priority non-EGU SIC categories in each state, the NOx-emitting equipment used, and their emissions contribution based on 2010 forecasts.

4. Reviewed and described state NOx control requirements that affect current and 2010 emissions from the equipment used in each high priority SIC category;

5. Described the level of emissions reductions, if any, needed to meet state NOx control requirements for the equipment used in each high priority SIC category

6. To develop a basis for comparison, we described the control requirements/technologies in place in Eastern Texas for each of the same high priority SIC categories.

7. We briefly compared the levels of control required in Eastern Texas with the states that are making a significant contribution to ozone episodes in Eastern Texas, and described in general terms the additional reductions (on a percentage basis) that might be achieved in each case from applying more advanced control technologies.

8. We provided general, off-the shelf information on the cost effectiveness of the various levels of control/technologies described above.

Limitations

There are a number of limitations to what is generally a top down approach that we used to evaluate potential emission reduction potential from SIC categories. Many of these limitations could be addressed by follow-on work.

1. The resources available to this study did not permit 1) a detailed comparative analysis that looks at individual emission limits, applicability thresholds, exemptions, optional provisions etc. nor 2) revising neighbor states emissions inventories to reflect “Texas-level controls.”

2. Except for some EGUs, we did not review the permit requirements for individual facilities and sources.

3. We make the simplifying assumption that sources and facilities within a SIC category are in compliance with applicable state regulatory NOx limits, or in the absence of applicable limits, that these sources are uncontrolled beyond their original permitting requirements. There may be many exceptions:

   Individual sources may have lower emissions than indicated by regulatory requirements. For example a facility may have undergone a modification that triggered New Source Review (NSR) or Prevention of Significant Deterioration (PSD) requirements and therefore installed control technology consistent with Lowest Achievable Emission Requirements (LAER) or Best Available Control Technology (BACT) respectively. A source may also have had to meet New Source Performance Standards (NSPS).

   Individual sources may have higher emissions than indicated by regulatory requirements if they are old enough to be “grandfathered”, are in some other way exempted, or are out of compliance.

   Some regulatory requirements apply only during the “ozone season” and therefore it may not have been cost-effective to install add-on control equipment to meet the emission limits. Other options would be to reduce process throughput during this season to fall below thresholds for rule applicability or, were permitted, use alternative control plans or emissions trading to meet the requirements of the rules.

4. We relied on the reliability or base year emissions inventories and 2010 emission forecasts produced by EPA and its contractors. Emissions inventories tend to be incomplete and forecasts inherently have considerable uncertainty.

5. Emissions information used in the analysis was not specific enough in most cases to relate individual sources to specific regulatory cutoffs. As a result, we did not know with any precision what part of the EI category was subject to a given state emissions limit.

6. We often made the simplifying assumption that sources and facilities within a SIC category could install more advanced control technology within the range of cost-effectiveness for that technology. Many individual sources have varying configurations and operating characteristics that affect both the technical feasibility of installing advanced controls and the cost.

7. The accuracy of the degree of control required by regulations was based on emission factors generally available in the literature that describe the typical uncontrolled emission level. Using these levels, the level of control required to meet applicable regulatory limits was determined. It was beyond the scope of this analysis to account for those sources that have controlled emissions to levels below typical uncontrolled levels as well as the incremental level of control and cost-effectiveness of some NOx emission control technologies.

8. The effectiveness and cost of various control technologies depend on many factors. For example, implementation of add on control equipment can sometimes be difficult, or even impossible, due to space limitations at a given facility, or at a given unit. This is particularly true for package units, which are less adaptable to such additions. One factor to consider is the capacity factor (a factor of how much the unit is used) of the unit being considered for control. A higher capacity factor will result in a lower cost-effectiveness. As a result the control technology and cost-effectiveness is generally identified by a range of results.

9. The analysis did not include all SIC categories. There are many pieces of equipment that might be controlled cost-effectively that are not included in the high priority categories.

10. The methodology looks at emissions on a statewide basis and does not consider that individual facilities can have varying impacts on Eastern Texas because of their location and operating characteristics.

3. PROPOSED CLEAN AIR INTERSTATE RULE

In late December 2003, EPA Administrator Michael Leavitt signed a proposed regulation to reduce sulfur dioxide and nitrogen dioxide emissions in 29 eastern states (and the District of Columbia) over a twelve-year period. The regulation, initially deemed the Interstate Air Quality Rule (IAQR), was later renamed the Clean Air Interstate Rule or CAIR. The proposal was published in the January 30, 2004 Federal Register and on June 10, 2004 a Supplemental Proposed regulation for the CAIR was published in the Federal Register. The goal of the NOx emission reductions was a 65% cut in emissions by 2015 from current levels. Total NOx emissions would be reduced by 1.5 million tons in 2010 and 1.8 million tons by 2015. The states affected by the regulations would be required to revise their SIPs to include measures to meet their specific allocation for NOx emission reductions in each of the two phases. EPA highly encouraged states to focus their SIP control efforts on EGUs using a cap and trade program similar to the existing EPA Acid Rain Program. These would be permanent emissions reductions and could not be increased at a later date. The Supplemental Proposal of June 2004 focused on reducing the emissions to assist states in attaining the new 8-hour ozone and fine particulate matter NAAQS. EPA believed that these rules, when final, along with recent regulations on Nonroad Diesel engines and other mobile source requirements under the 1990 Clean Air Act (CAA), would provide most, i.e., about 90%, of the non attainment areas the means to achieve the standards by the CAA deadlines. States can meet the emission reduction requirements by either joining the EPA-managed cap-and-trade program for power plants (established under the earlier NOx SIP Call) or achieve the reductions through controlling non-EGU point sources, area sources, or additional mobile source strategies.

EPA originally planned to publish a final CAIR in December 2004. However, in mid December EPA agreed to wait for final publication of CAIR until mid-March 2005 while the new Congress addressed, once again, the Clear Skies legislative proposal to reduce emissions of NOx, SO_2, and mercury from power plants. Clear Skies legislation did not progress under the previous Congress due to issues regarding failure to include carbon dioxide emissions. Previous Clear Skies proposals had a two-phase cap on NOx emissions of 2.19 million tons by 2008 and 1.79 million tons in 2018. Unlike the CAIR, Clear Skies would apply to all 50 states and replace both the current Acid Rain and NOx SIP Call strategies. Both EPA and the utility industry prefer Clear Skies legislation to CAIR regulation as it would provide more certainty and better insulation from litigation. The Senate Environment and Public Works Committee, after considerable debate and attempted compromises to consider carbon reductions, ended action on the Clear Skies legislation at the Committee level with a 9-9 tie vote on March 9, 2005. While the full Senate could consider the bill at a later date, this now appears highly unlikely.

Accordingly, on March 10 EPA proceeded to promulgate the final CAIR. While full analysis of the final CAIR is beyond the study commitment of this contract, a quick review of the final regulation shows the following major changes that might affect Texas:

- The first phase of the NOx reductions begins in 2009 rather than 2010
- Emissions inventories for the PM2.5 and 8-hour ozone modeling have been updated and improved
- Several states have been changed with regards to coverage by CAIR, and thus the NOx budgets for all states have been adjusted
- Measures can now be included in the revised SIPs that were previously required by other requirements of the CAA

- There is now an ozone season cap, so the NOx trading program has an ozone season cap as well as the previous annual NOx and Sox trading programs
- EPA put on notice *all* states a finding of non-submittal of a SIP addressing interstate transport. Those states that are not identified under the CAIR must still submit a sip showing that they do no significantly contribute to attainment problems for 8-hour ozone or PM2.5 in downwind States.

Texas is a part of CAIR for particulate matter, only, based on modeling that shows its sources significantly contribute to fine particle pollution in Illinois. However, modeling also shows that 8-hour ozone levels will improved due to reductions in NOx under CAIR in Alabama, Arkansas, Louisiana, and Mississippi. CAIR will have the following impacts upon attaining the 8-hour ozone standard in the 23 nonattainment counties in Texas:

- The San Antonio region will attain by 2010
- The Dallas-Fort Worth region will attain by 2015
- The Beaumont-Port Arthur region will be helped in its 2015 attainment by CAIR
- The Houston-Galveston region will be helped in reducing particulate pollution by CAIR

More information on how the March 10, 2005 final CAIR will affect Texas can be found at: http://www.epa.gov/interstateairquality/state/tx.html

Considerable use of the CAIR support data was used in this study.

Note: The following discussion, contained in the Draft H-36 Report, is generally still applicable to the final CAIR action on March 10, 2005. The previous section of this Chapter describes the major changes from the proposal to the final rule.

Some of the key features of the **January 30, 2004** CAIR proposal are as follows:

- Focus is on EGU emissions and controls, generally "extending" the NOx SIP call to 2010 and 2015 with greater emission reductions. EPA is only expecting SIP controls in the CAIR states (all our study area except Oklahoma) to meet the 2010 and 2015 emission budgets, and do that with controls nearly exclusively on EGUs. The proposal identifies the most "highly cost-effective" control for NOx as SCR, and possibly some NSCRs.
- EPA appears to highly discourage states from any new controls on non-EGUs. EPA believes that if the States meet the emission budgets, hopefully by region wide cap and trade programs, little additional control will be necessary.

Emission Inventories

- In preparing for the CAIR proposal, EPA developed a 2001 base year emission inventory for all categories (point, mobile, area) as the basis for the projected 2010 and 2015 inventories.
- For EGUs, EPA used the 2001 National Emission Inventory (NEI) EGU state totals. These were available, but not in modeling format nor for individual point sources, and thus served as a proxy for 2010 and 2015 projections. To get the 2001 EGU individual source emissions, EPA applied the 1996 NEI point-level emissions to the 2001 NEI state-

level, then added (or usually subtracted) the state proportional change to each individual EGU in that state.

- For non-EGUs, 2001 NEI state totals are not available, so EPA used a linear interpolation between gridded 1996 and 2010 (earlier data from a different analysis) base years to produce a 2001 gridded base year emission inventory. EPA believes this maintained consistency in the overall analysis.
- For the 2010 (and 2015) Base Case emission projects, EPA based this on *no other controls beyond those **already** promulgated in SIPs or expected to be promulgated before final CAIR rule.* Thus, no controls that will show up in 8-hour Ozone or PM2.5 SIPs are a part of these projections. EPA does, however, reflect projected economic growth in its analysis. They also include Tier 2 tailpipe standards, the NOx SIP Call, and RACT for NOx in 1-hour ozone NAAs. They do not include the NOx co-benefit effects of the proposed MACT regs for Gas Turbines or reciprocating internal combustion engines. Nor do they include effect of RACT in 8-hour ozone areas.

Emissions Control Requirements

- Focus on controlling EGUs - 23% total CAIR-state NOx emissions in 2010 and can employ highly cost effective controls (SCR).
- Non-EGU Boilers and Turbines – EPA does ***not*** assume or require any additional emissions reductions. The reasons given were that there is very little information on whether controls would be "highly cost-effective." Limited available data indicates low emission growth. With EGUs being taken out of the seasonal NOx SIP Call Trading Program, costs of compliance for non-EGUs will likely increase.

EGU Budgets and Control Requirements

- All control requirements in the CAIR proposal apply to EGUs.
- If a State requires EGUs to reduce budget, they *must* impose a cap on EGU emissions, i.e., emissions budget.
- If a State controls EGUs and "allows" them to participate in the region wide interstate cap-and-trade program, it *must* follow EPA rules for allocating allowances to individual EGUs.
- If a State chooses to control EGUs but *not* allow them to participate in the interstate cap-and-trade program, it can allocate allowances but *must* cap EGUs emissions.
- EPA expects most, and perhaps all states will elect to join the regional cap-and-trade program, similar to what occurred under the NOx SIP Call.
- The annual caps occur in 2010 (1.6 million tons) and 2015 (1.3 m. tons) to allow sources time to purchase and install the controls.[1]
- Important to note that these caps in the CAIR proposal are more stringent and occur sooner than in the previous Clear Skies proposals.
- The cost effectiveness component of the CAIR considers applicability, performance, reliability of different types of pollution control technologies, how many sources can install control technology, and whether the technology is compatible with the typical

[1] The final CAIR changed the 2010 date to 2009 for NOx

configuration of sources in that category. All this goes into the decision on meeting the 2010 or 2015 caps.

Control Technology for EGUs

- EPA concludes that SCR for NOx control on coal-fired boilers is fully demonstrated and highly cost-effective, with reduction capability of 90%, min. emission rate being 0.05 lb/mmBtu.
- Discussion, graphs, and tables on cost effectiveness of NOx Emission Reductions are identified in EPA's proposal (p. 4614). Marginal costs per ton reduced are $2,200 in 2010 and $2,000 in 2015. This is very low in terms of other control technologies.
- EPA predicts heavy reliance on SCR, and to a much lesser degree, on SNCR and gas re-burn.

Schedules

- Finalize the CAIR by early-2005 (still quite possible if Clear Skies legislation fails).
- SIPs will be due December 2006.
- Sources have first phase controls on by January 2010, second phase January 2015 (under Clear Skies by 2018).

SIP Requirements – States can choose

- Budget Approach: statewide cap for all sources in the state, with mechanisms to assure overall budget would not be exceeded. Approach works fine for point sources, much less for mobile and area sources.
- Emissions Reduction Approach: SIP imposes control requirements with emission rate limits or specified technology, but no cap. Works for mobile and area sources, but has difficult inventory issues.
- CAIR proposal: Hybrid approach, with SIP containing control requirements to assure specified amount of emission reductions, and referenced to the EGU budget for equivalent reductions. State can choose to control any source category it wants, but EGU sources must have a cap.
- If states choose to control non-EGUs, they must adopt and submit SIP revisions, extensive support documentation, and all the other complications of a SIP submittal. *However*, if State chooses to require emission reductions *only* from EGUs, then the SIP only has to consider the CAIR provisions and not deal with any other source categories or justifications.

Some of the key features of the **June 10 Supplemental Notice of Proposed Rule-Making (SNPRM)** are as follows:

General

The focus was on filling in the gaps in the January 30 proposed and to revise/add more supporting information. We believe that this makes the EPA desire for an EGU-only, interstate cap-and-trade program approach a mandate upon the states.

EGU Budgets

- Uses updated heat input data to refine and adjust the region wide NOx budgets. **Note:** EPA's Clean Markets Division put out a memo after the SNPRM on July 23, 2004, further correcting the State NOx budgets. [2]
- EPA restated that as long as a state met the NOx emission budgets, it could impose controls on EGUs only, on non-EGUs only, or on a combination of the two.

Other New SIP Control Requirements

- If States elect to impose controls on large, non-EGU industrial boilers and /or turbines, they also must impose an emissions cap on *all* such sources within the State.
- If a State chooses to obtain some or all its emission reductions from non-EGUs, the EGUs in the State could not participate in the EPA-administered multi-state cap and trade program.
- Credit for non-EGU reductions can only be from measures not otherwise required under the CAA.
- States using non-EGU reductions must commit in the CAIR SIP to replace emission reductions attributable to any CAIR SIP measure if that measure is subsequently determined to be required in meeting any other SIP requirement related to the adoption of control measures.
- Finally, EPA is adding fairly cumbersome emission inventory requirements for non-EGUs, and promises to review the results very closely.

NOx SIP Call – CAIR Would Mandate:

- States retain all SIP provisions from the original NOx SIPs.
- If States achieve all the mandated NOx reductions by including their EGUs in the region wide, annual NOx cap-and-trade program, EPA will consider that they automatically met the ozone season reduction requirements from the previous seasonal NOx cap-and-trade program.
- EPA will continue to run the NOx SIP Call cap-and-trade program for the non-EGUs.

The apparent limitations in the CAIR rule for controlling non-EGUs has raised significant concerns by the environmental community, state and local air pollution associations, and the utility industry. The SNPRM proposes a 0.5% threshold for the number of counties or parishes that would come into compliance with air quality standards before the agency would act on a petition, i.e., Section 126, to require further emission cuts in adjacent states. The 0.5 threshold

[2] The final CAIR rule provides new NOx budgets for all states affected by CAIR

would mean that before non-EGU sources such as pulp and paper mills, chemical plants, and refineries could be petitioned for controls upstate, about 16 additional counties would have to be shown to come into attainment by the action. The utility industry felt that the 0.5% threshold of significance was too low and that it would preclude inclusion of controlling non-EGUs. The environmental community felt the 0.5% threshold was arbitrary and without evidence to support, thus a likely target for litigation.

While this particular study is scheduled to be completed prior to any decision on a final CAIR rule or Clear Skies legislation, we would encourage Texas to closely follow the outcome and continue (or further) its analysis on the impacts of the eventual outcome on control measures needed to attain the 8-hour ozone standards in the state.

4. NOx REDUCTION POTENTIAL BY STUDY AREA STATE AND SOURCE CATEGORY

Overview

In this section we discuss the current regulatory framework for NOx control in the eight states identified in the H-35 study as potentially impacting Central and Eastern Texas 8-hour ozone non-attainment areas. Emissions offshore in the Gulf are also briefly discussed. NOx regulations in Central and Eastern Texas are discussed separately in Section 5. The data and discussions for each State is divided between Electric Generating Units (EGUs), SIC 4911 and non-EGU SIC source rules.

We have identified five priority source categories (SICs) that currently emit 75% of the NOx point source emissions in the three states immediately adjacent to eastern Texas and 82% of the emissions in the other 5 study area states. The most significant of these five priority categories, of course, is SIC 4911, EGUs, and we both analyzed the rules and identified the major facilities in all eight of the study area states. The four non-EGU SICs identified for potential rule and emission reviews were Crude Petroleum and Natural Gas, SIC 1311; Industrial Organic Chemicals, NEC, SIC 2869; Petroleum Refining, SIC 2911; and SIC 4922, Natural Gas Transmission. These particular SICs had a 6% or greater proportion of the State's point source NOx emissions in one or more of the study states. The EPA's most recent, complete, point source inventory, the 1999 National Emission Inventory (NEI), was used to identify the major sources and SIC categories.

We identified the major EGU point sources of NOx in each study state using EPA emissions inventory data and a cutoff of 1) 1.5 tons per day (tpd) for sources in the immediately adjacent states of Louisiana, Arkansas, and Oklahoma; 2) 5 tpd in the relatively nearby state of Mississippi; and 3) 10 tpd in the outlying study states of Alabama, Tennessee, Kentucky, and Missouri. Information is provided for two years; a 2001 base case (from the EPA CAIR technical support data) and a 2010 forecast (also from similar data sources). The 2001 individual EGU point source emissions were estimated by the EPA by applying the 1996 NEI state-level emissions to the 2001 NEI state-level (only 2001 NEI data was at state-level), then adding (or usually subtracting) the state proportional change to each individual EGU in the state. The 2010 base case emission scenarios for the individual EGUs shown in the point source tables under each study area state represents EPA's projected emissions in the absence of any further controls beyond measures already promulgated. They do represent projected economic growth in the state. These are the emissions that will need to be reduced under the proposed CAIR as part of each State's efforts to obtain the state's NOx budget in 2010. Section 3 describes the CAIR proposal in more detail.

For non-EGU categories, we report forecasted 2010 emissions based on emissions forecasts done to support the CAIR proposal. The 2010 non-EGU emission data was obtained from an EPA Technical Support Document, "Identification and Discussion of Sources of Regional Source NOx and SO2 emissions other than EGUs," January 2004. EPA did not have the state-level 2001 NEI totals available at the time of the initial CAIR proposal, so it used a linear interpretation between the gridded 1996 NEI data and the projected 2010 non-EGU base years to produce a 2001 non-EGU point source inventory. We did not report 2001 non-EGU point source emissions in this study as they 1) seemed much less reliable in accuracy and, 2) seemed of little value to analyzing the overall impact in 2010 to the study area findings and actions. Statewide 2010 non-EGU emissions, by both SIC and SCC, are contained in the data tables in the discussion of non-EGU regulations in the following state subsections of this Section. 2010 non-EGU point source emission are listed in Appendix G.

ALABAMA

Overview

Alabama is located on the outer edge of the study area states for the H-36 study and was found in the H-35 study's preliminary findings to have slightly exceed EPA's initial screening criteria as a potentially significant contributor to 8-hour ozone levels of >85 ppb in only the Austin Episode. The affected non-attainment areas were Houston-Galveston and Beaumont-Port Arthur, and the near non-attainment area of Northeast Texas. Accordingly, we limited our evaluation to point sources that exceeded 10 tpd emissions in 1999 and those SIC categories that contained over 6% of the total point source NOx emissions. Two SIC categories were found to exceed our 6% SIC cutoff criteria – SIC 4911, EGUs, and SIC 4922, Natural Gas Transmission (NGT). Eight EGUs and two NGT sources exceeded the 10 tpd criteria.

In 1999, EGUs emitted 185,800 tons of NOx in Alabama, dropping to 168,500 tons in 2001 base year. NGT facilities emitted 24,690 tons of NOx in 1999. In the 2010 base, all EGUs in Alabama were projected to emit a 134,100 tons of NOx and all non-EGU point sources a total of 83,400 tons of NOx. Total NOx emissions in Alabama in 2010 were projected at 453,000 tons. The proposed CAIR allocation for point source NOx in 2010 was initially set at 67,422 tons in the June 4, 2004 SNPRM, and then corrected slightly on July 23, 2004 to 64,359 tons in 2010 and 53,632 tons in 2015.

Alabama has one 8-hour ozone nonattainment area – the two-county (Shelby and Jefferson) Birmingham NAA. Birmingham is designated as a Basic NAA and thus must attain by June 2009. These two counties were also designated nonattainment for the one-hour ozone standard. In December 2004, EPA also designated five counties as nonattainment for PM2.5, including the three counties in the Birmingham area, and a county adjacent to Chattanooga, Tennessee and next to Columbus, Georgia metropolitan areas. Alabama joined the Ozone Transport Commission (OTC) states in May 2004 to be a part of the NOx Budget Trading Program (NBP).

Electric Generating Units (EGUs)

EGUs emitted 64.3% of all point source NOx emissions in Alabama in 1999 and thus offer the greatest potential for emission reductions under the CAIR budget. EGUs are currently regulated in Alabama under the NOx SIP Call, which requires large emission reductions from fossil fuel fired equipment during the ozone control season which is the period of May 1 through September 30. This includes large electric generating units, large industrial boilers and turbines, stationary internal combustion engines and cement kilns. Stationary internal combustion engines will be proposed for control in a Phase II submittal.

The sources impacted in the northern two-thirds of the state fall in the whole counties that lie above the 32° parallel. Controls are expected to be in place by May 31, 2004. The NOx SIP Call compliance guide and associated permit application forms. The NOx Budget Trading Program applies to stationary, fossil fuel-fired boilers, combustion turbines, or combined cycle systems ("units") in these counties, which include all the >10 tpd EGUs with the exception of the Alabama Power Company's Barry plant in Mobile County and the Alabama Electric Cooperative's Lowman plant in Washington County.

The Alabama state regulations specifically applying to NOx emissions from EGUs is 335-3-8-.03. The following is an excerpt of that rule as it applies to the Alabama Power Company's Miller and Gorgas power plants, the two largest emitters of NOx in the state:

> (1) Applicability. This Rule applies to existing coal-fired electric utility steam generating installations in Walker and Jefferson Counties.
>
> (2) During the compliance period specified in paragraph (3) below, no person shall cause or permit the operation of a coal-fired electric utility steam generating installation in Walker or Jefferson Counties in such a manner that nitrogen oxides (NO_X) are emitted in excess of the emission limits established by the Department in this Rule and specified in the Major Source Operating Permit for the affected unit(s). The BTU-weighted 30-day rolling average NO_X emission rate for the affected units shall be less than or equal to 0.21 pounds per million BTU of heat input, during the compliance period specified in paragraph (3) below.
>
> (3) Beginning May 1, 2003, and each year thereafter, the compliance period shall begin May 1 and end on September 30 of each year. Compliance is based on a 30-day rolling average.
>
> (a) The first calculated 30-day averaging period shall be May 1 through May 30.
>
> (b) The last calculated 30-day averaging period shall be September 1 through September 30.
>
> (4) Testing, Recordkeeping and Reporting.
>
> (a) Continuous emissions monitoring systems (CEMS) to measure nitrogen oxide emissions from each affected unit shall be installed and operated at locations approved by the Director. The CEMS shall meet the specifications and procedures of 40 CFR Part 75 and will be certified and maintained in accordance with 40 CFR Part 75. In addition, each of the CEMS shall undergo a relative accuracy test audit (RATA) on an annual basis at times approved by the Director.
>
> (b) Records of the 30-day average nitrogen oxide emission rate for the affected units shall be kept for a period of five (5) years.
>
> (c) A written report of the 30-day average nitrogen oxide emission rates for the affected units shall be submitted to the Department by the 15th day of each month during the period from May 1 to September 30 of each year. The first report shall be submitted by June 15 and shall include data for the month of May. The final report shall be submitted by October 15 and shall include data for the month of September.
>
> (d) Any exceedances of the NO_X emission rate specified in paragraph (2) of this Rule shall be reported to the Department within two (2) working days of the date of the exceedance.
>
> (e) Additional testing, recordkeeping, and reporting requirements may be necessary and will be specified by the Department at such times as they become necessary.

The other major EGUs are primarily controlled by PSD permits or through participation in the NOx Budget Trading Program.

Table 4-1 provides information on all EGU sources in Alabama that emitted over 10 tpd of NOx, both for their base year 2001 NOx emissions and projected 2010 NOx emissions.

ALABAMA

Table 4-1. Electric Generating Units, SIC 4911.

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[2,3]	New Controls-1999 to 2010 [2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Alabama	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons					
Miller Power Plant, Alabama Power Company (APC) (4 units)	Jefferson Co.	30,000	17.8	26,200	4,800	33.8	Coal	LowNOx (2 units),SCR, 03 (1 unit)	SCR, 05 (1 unit),	335-3-8-.03; 335-3-9-05	No
Gorgas Power Plant, APC (5 units)	Walker Co.	20,200	12.0	13,900	3,800	26.7	Coal	SCR, 02; Low NOx (1)		335-3-8-.03; 335-3-9-05	No
Widows Creek, TVA (8 units)	Jackson Co.	26,200	15.6	17,200	4,500	31.8	Coal	SCR, 02, 03		335-3-8-.03; 335-3-9-05	NA-NBP
Gaston Plant, APC (6 units)	Shelby Co.	29,400	17.4	20,200	4,600	32,2	Coal(5); Gas (1)	SCR (5)		335-3-8-.03; 335-3-9-05	NA-NBP
Barry Plant, APC (11 units)	Mobile Co.	22,800	13.5	22,400	9,900	69.7	Coal/Gas	Low NOx	SCR, 06	335-3-8-.03	No
Colbert Plant, TVA (11 units)	Colbert Co.	15,800	9.3	7,300	1,400	17.5	Coal(3); Gas (8)	SCR, 04; Low NOx 1	SCR, 05; Scrubber	335-3-8-.03; 335-3-9-05	NA-NBP
Greene County Plant, Alabama Electric Cooperative (AEC) (11 units)	Greene Co.	11,700	6.9	7,100	3,100	22.0	Coal(2); Gas (9)			335-3-8-.03; 335-3-9-05	NA-NBP
Lowman Plant, AEC (3 units)	Washington Co.	9,800	5.8	7,500	3,400	23.5	Coal			335-3-8-.03	No
All EGU (SIC 4922) Sources		168,500		134,100							

References:

1. NE1 2001 to IPM-NEEDS Matches, http://www.epa.gov/interstateairquality/pdfs/NEI2001_IPM-NEEDS_Matches.xls
2. Pechan report to EPA, EPA216a9c_2000_Pechan_toEPA
3. Argus SCR Report, May 4, 2004
4. Alabama Department of Environmental Management, Air Division Rule 335-3-8, Nitrogen Oxides Emissions

Discussion

Three companies or agencies own the eight major power plants in Alabama: The three owners are the Tennessee Valley Authority (TVA), Alabama Power Company, and the Alabama Electric Cooperative. The two TVA facilities are located along the Tennessee River in northern Alabama, near the Tennessee Valley. Four of the Alabama Power Company facilities are located near the large urban centers of the state – three near Birmingham and the other in Mobile. The other two APC and AEC facilities are located in more rural counties near the Mississippi border.

As noted earlier, six of the eight major EGU sources in Alabama are subject to the NOx SIP Call. The Barry Plant in Mobile County is not subject to the NOx Budget Trading Program and, with its projected 2010 NOx emissions ranking it as the second largest emitter in Alabama it should be seriously considered for additional controls. The peak daily summer day emissions from Barry are 69.7 tons, over twice that of any other EGU in Alabama. Six of the eight EGUs have installed, or plan to install SCR on several of their coal-burning units since 2002.

Non-EGUs

Natural Gas Transmission, SIC 4922

General Information

In addition to Electrical Generating Units, only one SIC category, Natural Gas Transmission (# 4911) has sufficient NOx emissions in Alabama to meet this study's screening criteria for further analysis. Table 4-2 summarizes 2010 emissions forecasts for Natural Gas Transmission.

2010 Emissions Forecasts

This category covers the field processing, compression and transmission of natural gas from production to storage areas. The NOx emissions inventory for Alabama lists a few large industrial boilers and a number of gas turbines in use, but the predominate type of equipment; with nearly 80% of the NOx emissions is IC engines (sometimes referred to as reciprocating engines). According to the emissions inventory forecasts, all combustion equipment will be natural gas-fired in 2010.

Table 4-2. Natural Gas Transmission, SIC 4922[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts		
				Emissions (tpy)	% of Total Alabama Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Stationary gas turbines	20200201	Statewide	Natural gas	2,084	2.5	21.4
Reciprocating IC engines	20200202	Statewide	Natural gas	7,641	9.2	78.6
Total				**9,725**	11.7	**100.0**

References:
[1] Pechan report to EPA, EPA216a9c, 2000

Estimated NOx emissions from Natural Gas Transmission (NGT) in 2010 are 9,725 tons per year, or 11.7% of non-EGU point source emissions.

Applicable State Regulations

Traditionally, Alabama has had no equipment-specific NOx emission limits for non-EGU gas turbines or IC engines. As a result, we assume that most NGT equipment is currently uncontrolled. However Alabama's northern counties are subject to the 1998 NOx SIP Call and have been assigned state emission reduction budgets it must meet in phases by 2007 and 2010. To meet this requirement Alabama adopted a NOx Trading Program in 2001 that assigned individual allocations to certain power plants and other sources with combustion units with rated capacities >250 MMBtu/hour. In December of 2004, the State amended this program to impose emission reduction requirements on "affected" large IC engines. An engine is "affected" if it was operated during the baseline period of the SIP Call regulation and was included in the NOx SIP Call inventory. It is "large" if it emitted more than 1 ton per day during the ozone season during the baseline period. This requirement is summarized in Table 4-3.

Table 4-3. Regulations for IC Engines in Alabama.

Regulatory Reference: Alabama Department Of Environmental Management, Air Division, 335-3-8-04				
Source: IC Engines				
Geographic Area	Applicability	Limits	Exemptions [3]	Percent reduction from uncontrolled for affected sources
"Fine Grid" portion of the state [1]	An affected engine which emitted a daily average > 1 ton per day of NOx during the baseline period.	Reduce projected 2007 ozone season base NO_X emissions by 82%	Units with < 1 ton per day of NOx emissions.	~83%
Rest of State	No limits except, presumably PSD BACT and NSPS when applicable		All units	0

[1] The "fine grid" portion of the state is comprised of the counties of Autauga, Bibb, Blount, Calhoun, Chambers, Cherokee, Chilton, Clay, Cleburne, Colbert, Coosa, Cullman, Dallas, De Kalb, Elmore, Etowah, Fayette, Franklin, Greene, Hale, Jackson, Jefferson, Lamar, Lauderdale, Lawrence, Lee, Limestone, Macon, Madison, Marion, Marshall, Morgan, Perry, Pickens, Randolph, Russell, St. Clair, Shelby, Sumter, Talladega, Tallapoosa, Tuscaloosa, Walker, and Winston.

[2] May 1-September 30

It is beyond the scope of this study to determine which, if any individual NGT units are subject to the emissions trading rule, but many compressor stations are equipped with IC engines that are large enough to emit more than 1 ton per day of NOx if they are uncontrolled. If any units are subject to the rule, they will either have to reduce their emissions by 80-90% or acquire sufficient reduction credits from other sources.

ARKANSAS

Overview

Arkansas borders on the northeast side of Texas and thus is one of the three states having the potential, geographically, to have most significant impacts upon the Texas SIP areas. The closest SIP area in Texas is the Northeast Texas NNAA. Its most significant impact upon that region was under the conditions of the Houston-Galveston/Beaumont Port Arthur episode. The H-35 study preliminary results showed an impact of 17.2 ppb maximum 8-hour ozone contribution to the Dallas-Fort Worth NAA and 17.8 ppb to the Northeast Texas NNAA. Overall, Arkansas was found by the H-35 study to exceed the significance criteria in at least one episode for each of the Texas NAAs.

Because of the location and impacts of Arkansas on Northeast Texas, we evaluated point sources that exceeded 1.5 tpd emissions in 1999. Four SIC categories were found to exceed our 6% SIC cutoff criteria – SIC 2611, Pulp Mills, SIC 2621, Paper Mills, SIC 4911, EGUs, and SIC 4922, Natural Gas Transmission. Seven EGUs, 9 NGT sources, 2 pulp mills, and 2 paper mills exceed the 1.5 tpd criteria.

In 1999, EGUs emitted 51,600 tons of NOx in Arkansas, dropping to 47,500 tons in the 2001 base year. In the 2010 base case, all EGUs in Arkansas were projected to emit 52,500 tons of NOx and all non-EGU point sources a total of 18,600 tons of NOx. Total NOx emissions in Arkansas in 2010 were projected at 221,100 tons. The proposed CAIR allocation for point source NOx in 2010 was initially set at 24,919 tons in the June 4, 2004 SNPRM, and then corrected slightly on July 23, 2004 to 23,537 tons in 2010 and 19,614 tons in 2015.

Arkansas has only one county designated as an 8-hour nonattainment area – Crittenden County, which forms the western portion of the Memphis Ozone Nonattainment Area. Under the "Downward Reclassification" provisions of EPA regulations, the Memphis area petitioned in July 2004 to be reclassified to Marginal from Moderate. EPA approved the request in September 2004 and the area must now meet the 8-hour ozone standard by 2007 under the Marginal Area regulatory deadlines. There were no areas designated for PM 2.5 nonattainment in Arkansas. Arkansas is not part of the NOx Budget Trading Program (NBP).

Electric Generating Units (EGUs)

EGUs emitted 50.2% of all point source NOx emissions in Arkansas in 1999 and thus offer the greatest potential for emission reductions under the CAIR budget. As noted above, however, they are not subject to the NOx SIP Call.

Air pollution control regulations in Arkansas are contained in Regulation 19 of the Arkansas Pollution Control and Ecology Commission (APC&EC), most recently revised in December 2004 and known as the "Plan of Implementation for Air Pollution Control." Since all of the major EGU sources are located in attainment areas, they are primarily subject to Chapter 9, Prevention of Significant Deterioration requirements. They must also comply with Chapter 5, General Emissions Limitations Applicable to Equipment, and in particular the visible emission regulations and the stack height/dispersion regulations. Other requirements are contained in APC&EC's Regulation 18, the Arkansas Air Pollution Control Code and Regulation 26, Arkansas Operating Air Permit Program. Federal requirements affected EGUs in Arkansas include NSPS for fossil-fuel-fired steam generators, Title V permitting, and Title IV (Acid Rain) programs.

Table 4-4 provides information on the major EGU sources in Arkansas, both for their base year 2001 NOx emissions and projected 2010 NOx emissions. All EGUs emitting over 1.5 tpd in 1999 are included.

ARKANSAS

Table 4-4. Base Year and Forecast EGU Emissions for Electric Generating Units, SIC 4911

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[2,3]	New Controls-1999 to 2010 [2,3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Arkansas	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons					
White Bluff Power Plant (2 units)	Jefferson Co.	19,200	40.4	22,300	9,900	70.7	Coal	Overfire Air	None	Reg 19, APC&EC	No
Independence Power Plant (2 units)	Independence Co.	18,600	39.2	20,800	9,200	66.0	Coal	Low NOx Burner	None	Reg 19, APC&EC	No
Flint Creek P.P.	Benton Co.	5,900	12.4	8,300	3,700	26.4	Coal	Low NOx Burner	None	Reg 19, APC&EC	No
Lake Catherine P.P; (4 units)	Hot Spring Co.	2,100	4.4	0	0	0	Oil/Gas Steam	Oil/Gas Early Retirement	NA	NA	NA
Robert E. Ritchie P.P. (3 units)	Phillips Co.	234	<1	0	0	0	Gas	Oil/Gas Early Retirement	NA	NA	NA
Hamilton Moses P.P.	St. Francis Co.	78	<1	0	0	0	Oil/Gas Steam	Oil/Gas Early Retirement	NA	NA	NA
McClellan P.P.	Franklin Co.	545	1.1	No Data					NA	NA	NA
All EGU (SIC 4922) Sources		47,500		52,500							

References:

1. NE1 2001 to IPM-NEEDS Matches, http://www.epa.gov/interstateairquality/pdfs/NEI2001_IPM-NEEDS_Matches.xls
2. Pechan report to EPA, EPA216a9c_2000_Pechan_toEPA
3. Argus SCR Report, May 4, 2004

4 Regulation 19 of the Arkansas Pollution Control and Ecology Commission

Discussion

The major power plants in Arkansas are generally located in relatively rural counties of the state, with the exception of the White Bluff power plant, owned by Entergy Service and located near Pine Bluff. The Flint Creek power plant is located near the border with Oklahoma and the Robert Ritchie facility is on the Mississippi River adjacent to Mississippi.

The three largest power plants in Arkansas burn low-sulfur coal imported from Wyoming. All other EGUs in Arkansas either currently use, or will by 2010 use gas as a fuel. Three of the non-coal burning major power plants in 1999 are assumed to be phased out by 2010 under EPA's CAIR projections. A fourth facility, the McClellan power plant in Franklin County, was not reported on in the 2010 data base and can be assumed to be phased out. To meet the proposed CAIR NOx budget allocation of 23,537 tons in 2010, Arkansas will need to reduce NOx emissions by 44% from the 2010 Base Case projections if it solely uses EGU emission reductions. However, by considering other, non-EGU sources, that reduction becomes 34%. Based on the above data, it would appear that the White Bluff and Independence power plants have the potential for the greatest reduction of NOx in Arkansas beyond projected control levels.

Non-EGUs

We made an exception and did not evaluate two SIC categories with emissions that slightly exceeded the 6% cutoff in Arkansas. They are SIC 2611, Pulp Mills, and SIC 2421, Paper Mills. A relatively small number of facilities produced the NOx emissions from these categories, primarily from process boilers that fired a variety of fuels, including wood bark, fuel oil and natural gas. In the absence of state regulations affecting these facilities, we did not believe we could provide meaningful information about control potential without accessing specific information on each of the individual facilities. NOx emissions from pulp and paper mills were small in the other states we reviewed, including Texas.

General Information

In addition to Electrical Generating Units, and the two SICs discussed above, only one SIC category, Natural Gas Transmission (# 4911) has sufficient NOx emissions in Arkansas to meet this study's screening criteria for further analysis. Table 4-5 summarizes 2010 emissions forecasts for Natural Gas Transmission.

2010 Emissions Forecasts

This category covers the field processing, compression and transmission of natural gas from production to storage areas. The point source NOx emissions inventories for Arkansas lists just two large, natural gas-fired IC engines in operation in SIC 4922.

Table 4-5. Natural Gas Transmission, SIC 4922[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Trends		
				Emissions (tpy)	% of Total Arkansas Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Reciprocating IC Engines	20200202	Statewide	Natural gas	1,063	5.6	100.0
Total				**1,063**	**5.6**	**100.0**

References:
[1] Pechan report to EPA, EPA216a9c, 2000.

Estimated NOx emissions from Natural Gas Transmission (NGT) in 2010 are 1,063 tons per year, or 5.6% of the non-EGU point source emissions.

Applicable State Regulations

Arkansas has no regulatory requirements that prescribe NOx emission limits for IC engines. While it is not within the scope of this study to review individual permits to determine whether equipment specific emission limits are applied to facilities, we attempted to do so in this case because of the small number of sources listed in the inventory. While we did confirm that the units listed in the inventory are currently uncontrolled, we also noted that the same facility operates a total of nine large, natural-gas-fired IC engines, plus several other NOx sources. The nine IC engines at this facility each have a Potential to Emit (PTE) for NOx that ranges from 446 tons per year to 1138 tons per year. (ADEQ Operating Permit # 1587-AOP-R1, Natural Gas Pipeline of America, Station 308). Moreover the same owner operates at least two other compressor stations in the state that are similarly equipped. We do not know why the referenced 2010 emissions forecast for Arkansas does not list other facilities and sources for SIC 4922, but the apparent discrepancy shows the difficulty of drawing sweeping conclusions from inventory data. It appears that NOx emissions may be greater than the inventory indicates and therefore that the potential to reduce emissions from NGT in Arkansas is also more significant than indicated by the inventory. Additional study is needed to more fully understand the contribution and control potential of this category.

KENTUCKY

Overview

Kentucky is located on the outer edge of the study area states for the H-36 study, located the furthest from Texas of any of our eight study states. The H-35 study's preliminary findings showed Kentucky to have slightly exceed EPA's initial screening criteria as a potentially significant contributor to 8-hour ozone levels of >85 ppb in Texas nonattainment areas for only the Austin and Houston-Galveston/Beaumont Port Arthur episodes. The affected non-attainment areas were Houston-Galveston and Beaumont-Port Arthur, and the near non-attainment area of Northeast Texas. Accordingly, we limited our evaluation to point sources that exceeded 10 tpd emissions in 1999. Only one SIC category were found to exceed our 6% SIC cutoff criteria –

SIC 4911, EGUs. Seventeen EGUs and two-EGU sources exceeded the 10 tpd criteria. The non-EGU sources included a cement company (SIC 3241) and a petroleum refinery (SIC 2911).

In 1999, EGUs emitted 310,200 tons of NOx in Kentucky, dropping to 233,600 tons in the 2001 base year. In the 2010 base case, all EGUs in Kentucky were projected to emit 195,900 tons of NOx and all non-EGU point sources a total of 34,800 tons of NOx. Total NOx emissions in Kentucky in 2010 were projected at 476,400 tons. The proposed CAIR allocation for point source NOx in 2010 was initially set at 77,938 tons in the June 4, 2004 SNPRM, and then corrected slightly on July 23, 2004 to 73,710 tons in 2010 and 61,425 tons in 2015.

Kentucky has portions of four interstate 8-hour nonattainment areas – Cincinnati, Louisville, Huntington-Ashland, and Clarksville-Hopkinsville. They are all Subpart 1 (Basic) NAAs and thus have to meet the standard by 2009 (with 5-year extension possible). The 8-hour ozone NAA counties in Kentucky are all under a 1-hour maintenance SIP as well. Kentucky also has four separate PM2.5 NAAs – Louisville, Cincinnati, and Ashland-Huntington interstate areas and Lexington intrastate NAA. Kentucky joined the Ozone Transport Commission (OTC) states in May 2004 to be a part of the NOx Budget Trading Program (NBP).

Electric Generating Units (EGUs)

EGUs emitted 86.2% of all point source NOx emissions in Kentucky in 1999 and thus offer the greatest potential for emission reductions under the CAIR budget. As Kentucky is an active partner in the NOx Budget Trading Program, EGUs are primarily regulated through NOx allocation allowances as assigned by the US EPA and approved in the Kentucky SIP. There are very specific formulas contained in Chapter 51.160 of Title 401 of the Kentucky Administrative Regulations which apply to the Kentucky Department of Environmental Protections. Section 160 describes NOx requirements for EGUs, industrial boilers, and turbines. For the 2004 to 2006 period, 95% of the allocated NOx emissions are for sources in operation before May 2001. The remaining 5% of the NOx allocation is maintained by the State (Commonwealth). After 2006, 98% are allocated and 2% held by the State.

Chapter 59.016 defines standards of performance for new EGUs. NOx reduction requirements for coal-derived solid fuels are 65% of the potential combustion concentrations. Liquid fuels have a 30% reduction requirement and gaseous fuels a 25% reduction requirement. Potential combustion concentration, which is the theoretical emissions in lb/MM BTU heat input that would result from combustion of a fuel in an unclean state (no emission controls) for NOx is: 0.67 lb/MM BTU heat input for gaseous fuels, 0.72 lb/MM BTU heat input for liquid fuels, and 2.30 lb/MM BTU heat input for solid fuels.

There are also extensive regulations for existing sources in Section 61 of the regulations.

Table 4-6 provides information on the major EGU sources in Kentucky, both for their base year 2001 NOx emissions and projected 2010 NOx emissions. All EGUs emitting over 10 tpd in 1999 are included.

KENTUCKY

Table 4-6. Base Year and Forecast EGU Emissions for Electric Generating Units, SIC 4911.

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[1, 3]	New Controls-1999 to 2010[2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Kentucky	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons					
Paradise Plant-TVA (3 units)	Muhlenberg Co.	54,600	23.4	44,400	3,300	16.7	Coal	SCR	NA	Chapter 51.160	NA-NBP
Ghent - LG&E Energy (4 units)	Carroll Co.	22,400	9.6	24,400	1,800	12.7	Coal	SCR (3 units)	SCR(1)	Chapter 51.160	NA-NBP
Shawnee Plant – TVA (10 units)	McCraken Co.	18,700	8.0	19,900	8,800	62.2	Coal	Low NOx Burner (6 un.)		Chapter 51.160	NA-NBP
Mill Creek – LG&E Energy (4 units)	Jefferson Co.	17,600	7.5	17,700	3,200	22.9	Coal	SCR (2 units), Low NOx Burner (2 un.)	SCR (1)	Chapter 51.160	NA-NBP
Big Sandy PP – AEP (2 units)	Lawrence Co.	19,900	8.5	14,200	2,300	16.1	Coal	SCR (1 unit), Low NOx Burner(1 unit)		Chapter 51.160	No
H.L. Spurlock Plant-East KY Power Coop. (2 units)	Mason Co.	11,700	5.0	7,400	500	3.8	Coal	SCR	NA	Chapter 51.160	NA-NBP
Elmer Smith PP-Owensboro Municipal Utilities (2 units)	Daviess Co.	14,200	6.1	5,600	1,600	11.5	Coal	SCR (1 unit-constr. 04), (1), Low NOx Burn (1		Chapter 51.160	No
East Bend PP-Cinergy (1 unit)	Boone Co.	8,200	3.5	4,600	300	2.4	Coal	SCR	NA	Chapter 51.160	NA-NBP
D.B. Wilson PP-LG&E Energy (1 unit)	Ohio Co.	9,600	4.1	4,500	300	2.4	Coal	SCR	NA	Chapter 51.160	NA-NBP
E.W. Brown PP-LG&E Energy (3 coal units, 6 gas units)	Mercer Co.	7,700	3.3	8,200	3,100	22.0	Coal	SCR (1 unit), Low NOx Burner (2 unit)	SCR (2 units)	Chapter 51.160	NA-NBP
Cane Run PP (3 units)	Jefferson Co.	7,200	3.1	9,000	2,000	13.7	Coal	Low NOx(2 unit), Overfire Air (1)	SCR (2 units)	Chapter 51.160	NA-NBP
Trimble County PP-LG&E Energy (1 unit)	Trimble Co.	6,900	3.0	4,100	300	2.1	Coal	SCR	NA	Chapter 51.160	NA-NBP
R.D. Green PP-Western KY Energy (2 units)	Webster Co.	7,800	3.3	7,000	3,100	22.1	Coal			Chapter 51.160	NA-NBP
Coleman PP – Western KY Energy (3 units)	Hancock Co.	7,400	3.2	6,000	2,300	16.1	Coal	Low NOx Burner (3 un.)		Chapter 51.160	NA-NBP
Robert Reid PP – Western KY Energy (2 units)	Webster Co.	5,600	2.4	900	300	2.3	Coal (1); Gas (1)			Chapter 51.160	NA-NBP
Cooper PP – East KY Power Coop (2 units)	Pulaski Co.	4,600	2.0	3,800	800	5.7	Coal	SCR (1 unit)		Chapter 51.160	NA-NBP
All EGU (SIC 4922) Sources		233,600		195,900							

KENTUCKY

Table 4-6. Base Year and Forecast EGU Emissions for Electric Generating Units, SIC 4911.

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[1, 3]	New Controls- 1999 to 2010[2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Kentucky	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons					

References:

1. NE1 2001 to IPM-NEEDS Matches, http://www.epa.gov/interstateairquality/pdfs/NEI2001_IPM-NEEDS_Matches.xls
2. Pechan report to EPA, EPA216a9c_2000_Pechan_toEPA
3. Argus SCR Report, May 4, 2004
4. Kentucky Administration Regulations

Discussion

The Shawnee, Owensboro, Mill Creek, Cane Run, and East Bend power plants are located in relatively urban areas. Many of the remaining facilities are located along the Ohio and other major rivers in the Commonwealth.

With 86.2% of all the stationary source NOx emissions in Kentucky, EGUs are quite large (emissions and generating capacity) and numerous in the Commonwealth. Sixteen facilities emitted over 10 tpd, our cutoff size for this outlying state in the study area. There are five very large EGUs (greater than 14,200 tons per year projected in 2010), with two of these owned by TVA, two by Louisville Gas and Electric, and one by American Electric Power. The source of fuel for all these facilities is coal, and the pollution controls are usually either Selective Catalytic Retrofit (SCR) or Low NOx Burners. With the exception of TVA's Shawnee Plant, they all have or are planning to install SCR by 2010. Furthermore, Shawnee is projected to emit 62.2 tons of NOx on a peak summer day in 2010 – nearly three times that of any other Kentucky EGU. Therefore, Shawnee should be seriously considered for additional controls. Other EGUs with less than adequate controls for NOx include the R. D. Green and Robert Reid power plants, both owned by Western Kentucky Energy. As all EGUs in Kentucky are potentially subject to the NBP allocations, it is not possible within the scope of this study to determine whether existing controls are more stringent than Texas rules.

Non-EGUs

No SIC categories with 6% or more of the Statewide NOx point source emissions exist in Kentucky.

LOUISIANA

Overview

Louisiana borders on the east side of Texas and thus is one of the three states having the potential, geographically, to have most significant impacts upon the Texas SIP areas. The closest SIP areas in Texas are the Houston-Galveston 8-hour Ozone NAA, the Beaumont-Port Arthur 8-hour Ozone NAA, and the Northeast Texas NNAA. Several large urban and industrial areas in Louisiana also are located close to the Texas border – Lake Charles and Shreveport. Due to the size and complexity of the various sources of NOx pollution in Louisiana, and the relative proximity of these sources to Texas, Louisiana is clearly the state having the greatest impact on 8-hour ozone levels in eastern Texas. Accordingly, we focused our evaluation on point sources that exceeded 1.5 tpd emissions in 1999.

The H-35 study's preliminary findings showed Louisiana to have exceeded EPA's initial screening criteria as a potentially significant contributor to 8-hour ozone levels in every NAA and near-NAA in almost all episodes in Texas. In the Austin episode, Louisiana contributions to 8-hour ozone levels ranged from 5.9 ppb in the Corpus Christi NNA to 28.4 ppb in the Beaumont-Port Arthur NAA. In the Houston-Galveston/Beaumont-Port Arthur (H-G/B-PA) episode, Louisiana contributed 75.6 ppb to the B-PA NAA, nearly as much as did the rest of the state of Texas. Louisiana also had a major impact on the Northeast Texas near-NAA, contributing 37.2 ppb in the HG/BPA episode and 39.8 ppb during the Dallas-Fort Worth episode. Clearly, additional controls of NOx emissions in Louisiana would have important impacts on assisting NAAs and near-NAAs attain the 8-hour ozone standard.

Only one SIC category were found to exceed our 6% SIC cutoff criteria – SIC 4911, EGUs. In 1999, nineteen EGUs and 101 non-EGU sources exceeded the 1.5 tpd criteria. Two of these EGUs were no longer considered major in the CAIR 2001 data base and thus were not analyzed.

In 1999, EGUs emitted 109,000 tons of NOx in Louisiana, dropping to 88,300 tons in the 2001 base year. In the 2010 base case, all EGUs in Louisiana were projected to emit 49,800 tons of NOx and all non-EGU point sources a total of 297,100 tons of NOx. Total NOx emissions in Louisiana in 2010 were projected at 744,700 tons. The proposed CAIR allocation for point source NOx in 2010 was initially set at 47,339 tons in the June 4, 2004 SNPRM, and then corrected slightly on July 23, 2004 to 50,783 tons in 2010 and 42,319 tons in 2015.

Louisiana has one 8-hour ozone NAA – the five parish Baton Rouge Intrastate NAA, classified as Marginal. These five parishes were formerly classified as Severe-15 for 1-hour ozone nonattainment. There were not PM2.5 areas designated as nonattainment in Louisiana, nor are there any PM10 nonattainment areas. Louisiana is not part of the NOx Budget Trading Program (NBP).

Electric Generating Units (EGUs)

EGUs emitted 31.4% of all point source NOx emissions in Louisiana in 1999, the largest individual SIC category for NOx emissions in the state. As Louisiana is not a part of the NBP, the emissions from EGUs in the state are regulated by specific emission "factors." Regulations in Louisiana are contained in Title III, Environmental Quality, Part III.Air. Chapter 22 specifically covers the control of emissions from NOx for the one ozone nonattainment area, Baton Rouge, and adjacent four parish Region of Influence. This area contains four of the 17 major EGUs in Louisiana. The following tables summarize the emission limits for EGU boilers in these two areas:

Table D-1A. Emission Factors for Sources in the Baton Rouge Nonattainment Area

Category	Maximum Rated Capacity	NOx Emission Factor
Electric Power Generating System Boilers:		
Coal-fired	>/= 40 to < 80 MMBtu/Hour	0.50 pound/MMBtu
	>/= 80 MMBtu/Hour	0.21 pound/MMBtu
Number 6 Fuel Oil-fired	>/= 40 to < 80 MMBtu/Hour	0.30 pound/MMBtu
	>/= 80 MMBtu/Hour	0.18 pound/MMBtu
All Others (gaseous or liquid)	>/= 40 to < 80 MMBtu/Hour	0.20 pound/MMBtu
	>/= 80 MMBtu/Hour	0.10 pound/MMBtu
Industrial Boilers	>/= 40 to < 80 MMBtu/Hour	0.20 pound/MMBtu
	>/= 80 MMBtu/Hour	0.10 pound/MMBtu

Table D-1B. Emission Factors for Sources in the Region of Influence		
Category	Maximum Rated Capacity	NOx Emission Factor
Electric Power Generating System Boilers:		
Coal-fired	>/= 80 MMBtu/Hour	0.21 pound/MMBtu
Number 6 Fuel Oil-fired	>/= 80 MMBtu/Hour	0.18 pound/MMBtu
All Others (gaseous or liquid)	>/= 80 MMBtu/Hour	0.10 pound/MMBtu
Industrial Boilers	>/= 80 MMBtu/Hour	0.10 pound/MMBtu

EGUs in areas outside the Baton Rouge NAA and Region of Influence must meet more traditional requirements such as Title V operating permits, the Acid Rain Program, NSPS, New Source Review or Prevention of Significant Deterioration permits, etc. These are generally found in Chapter 5, Part III of Title III of the Louisiana rules. There is also an Emission Reduction Credit (ERC) banking program in Louisiana (see Chapter 6). We would encourage HARC and TCEQ to consider having the consultants examine the permits for those EGUs in Louisiana that appear to have the potential for additional controls of air pollution as this is beyond the scope and resources of this initial study.

Table 4-7 provides information on the major EGU sources in Louisiana, both for their base year 2001 NOx emissions and projected 2010 NOx emissions. All EGUs emitting over 1.5 tpd in 1999 are included.

LOUISIANA

Table 4-7. Base Year and Forecast EGU Emissions for Electric Generating Units, SIC 4911.

		2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]							
Plant	Location	Emissions tpy	% EGU source emissions in Louisiana	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons	Fuel Type	Pollution Controls[1, 3]	New Controls-1999 to 2010[2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
Big Cajun 2 Power Plant-(3 units)	Pointe Coupee Parish	21,200	24.0	19,600	8,700	61.9	Coal	Low NOx Burner		Chap 22, Table D-1B	No
Ninemile PP-Entergy-5 units	Jefferson Par.	9,200	10.4	0	0	0	Gas(3)	Oil/Gas Early Retirement (O/GER)		Part III, Chap 5	NA
Michoud PP-Entergy-3 units	St. Charles Par.	5,200	5.9	1,700	700	NA	NA	0/GER		Part III, Ch. 5	NA
Nelson PP-Entergy-7 units	Calcasieu Par.	9,200	10.4	6,300	2,800	19.9	Coal(1), Gas(4), Fossi lWaste(2);	0/GER (3 units)		Part III, Ch. 5	No
Rodemacher Power Station-Cieco Corp.-2 units)	Rapides Par.	6,500	7.4	8,900	4,000	28.3	Coal(1), Gas (1)	Low NOx Bu(C), Ovenfire Air(G)		Part III, Chap 5	No
Dolet Hills Power Station-Cieco Corp.-1 unit	De Soto Par.	9,900	11.2	11,600	5,100	36.736.7	Coal	Low NOx B.		Part III, Ch. 5	No
Little Gypsy PP-Entergy-3 units	St. Charles Par.	5,900	6.7	0	0	NA	Gas	0/GER		Part III, Ch. 5	NA
Willow Glen PP-Entergy-5 units	Iberville Par.	4,600	5.2	0	0	NA	Gas(2)	0/GER		Chap 22, Table D-1A	NA
Louisiana Station 2B-Entergy-9 units (1 unit turbine, 8 units oil/gas-steam)	East Baton Rouge Par.	2,300	2.6	0	0	NA	Oil/Gas	Low NOx Burner (1)	Early Retirement (4 units)	Chap 22, Table D-1A	NA
Waterford PP-Entergy -2 units	St. Charles Par.	3,600	4.1	0	0	NA	Gas	0/GER (2)		Part III, Ch. 5	NA
Teche Power Sta.-Cieco Corp.-3 units	St. Mary Par.	1,400	1.2	0	0	NA	Gas(2)	0/GER		Part III, Ch. 5	NA
Sterlington PP-Entergy-4 units	Ouachita Par.	2,200	2.5	125	125	0.1	Gas	0/GER		Part III, Ch. 5	NA
Nisco PP-Entergy	Calcasieu Par.	2,000	2.3	No Data Available in CAIR						Part III, Ch. 5	NA
Big Cajun 1 PP-2 units	Pointe Coupee Parish	100	0.1	0	0	NA	Gas(1)	0/GER (2)		Chap 22, Table D-1B	NA
A.B. Paterson PP-Entergy-3 units	Orleans Par.	300	0.3	0	0	NA	Gas(1)	0/GER (2)		Part III, Ch. 5	NA
Evangeline Power	Evangeline	1,600	1.8	500	200	1.7	Gas			Part III, Ch.	NA

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Table 4-7. Base Year and Forecast EGU Emissions for Electric Generating Units, SIC 4911.

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[1, 3]	New Controls-1999 to 2010[2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Louisiana	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons					
Sta-Cieco Corp-5 un.	Par									5	
Bonin Power Sta-City of Lafayette-3 un.	Lafayette Par.	600	0.7	0	0	NA	Gas(2)	0/GER		Part III, Ch. 5	NA
Misc Locations-total of 6 units (3 turbine and 3 combined cycle units)	Misc			1,100	700	5.0	Gas	SCR(all)	NA		NA
All EGU (SIC 4922) Sources		88,300		49,800							

References:

1. NE1 2001 to IPM-NEEDS Matches, http://www.epa.gov/interstateairquality/pdfs/NEI2001_IPM-NEEDS_Matches.xls
2. Pechan report to EPA, EPA216a9c_2000_Pechan_toEPA
3. Argus SCR Report, May 4, 2004
4. Louisiana Administrative Regulation, Title 33 Environmental Quality, Part III. Air, Chapter 22. Control of Emissions of Nitrogen Oxides.

Discussion

Two of the major EGUs are located in the Baton Rouge Ozone NAA (Willow Glen and Louisiana Station 2B) two more in the Region of Influence (Big Cajun 1 and 2), and two more immediately adjacent to the Texas border (Dolet Hills and Nelson). Three of these four EGUs remain among the four largest NOx emitters under CAIR's 2010 projections. However, with the considerable conversions and early retirements of oil and gas-fired power plants projected by 2010, there remain only four large NOx EGU sources that comprise 93% of all EGU NOx emissions in Louisiana. The power plants are: Big Cajun 2, Nelson, Rodemacher, and Dolet Hills. Those power plants all burn coal in one or more of their units, and total emissions projected in 2010 are 46,400 tons which, even if fully converted from coal or phased out, would not have enough emission reductions to meet the CAIR 2010 budget for Louisiana of 50,783 tons. It would be anticipated that Louisiana will likely impose regulations on those four EGUs to obtain as much as possible of its NOx emission reductions to meet the 2010 budget. Accordingly, Louisiana will need to look at controls from non-EGUs and/or non point sources of NOx emissions to meet its proposed emission quota. And, states outside of Louisiana that are encouraging more stringent regulations of Louisiana sources should focus on non-EGUs as well.

Non-EGUs

General Information

In addition to Electrical Generating Units, five SIC categories have sufficient NOx emissions in Louisiana to meet this study's screening criteria for further analysis. They are Natural Gas Transmission (# 4911), Crude Petroleum and Natural Gas, (# 1311), Natural Gas Liquids, (#1321), Industrial Organic Chemicals, NEC (#2869), and Petroleum Refining (# 2911). While SIC 1321 is only 4.4% of the state's NOx point source emissions (based on 1999 Emissions Inventory), we included that source in this analysis due to its close relationship to SIC 1311 and due to the fact that it was projected to increase to 6.2 % of the state's NOx point source emissions in 2010.. Tables 4-8 through 4-12 below summarize 2010 emissions forecasts for these categories.

2010 Emissions Forecasts

Table 4-8. Natural Gas Transmission, SIC 4922[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts: Emissions (tpy)	% of Louisiana Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Stationary gas turbines	20200201 20300202	Statewide	Natural gas	6,633	2.2	8.2
Compressors	31000203	Statewide	Natural gas	4,334	1.5	5.4
Reciprocating IC engines	20200202 20200252	Statewide	Natural gas	69,749	23.7	86.4
Total				**80,715**	**27.4**	**100.0**

Table 4-9. Crude Petroleum and Natural Gas, SIC 1311[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts: Emissions (tpy)	% of Louisiana Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Reciprocating IC engines	20200202	Statewide	Natural gas	30,625	10.4	96.5
Compressors	31000203	Statewide	Natural gas	1,111	0.4	3.5
Total				**31,736**	**10.8**	**100.0**

References:

[1] Pechan report to EPA, EPA216a9c, 2000

Table 4-10. Natural Gas Liquids, SIC 1321[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts: Emissions (tpy)	% of Louisiana Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Stationary gas turbines	20200201	Statewide	Natural gas	3,064	1.0	16.7
Industrial Boilers	10200601 10200602 10200603	Statewide	Natural gas	5,840	2.0	31.9
Refinery Process heaters	30600104	Statewide	Natural gas	1,656	0.6	9.0
Reciprocating IC engines	20200202	Statewide	Natural gas	6,452	2.2	35.2
Compressors	31000203	Statewide	Natural gas	1,302	0.4	7.1
Total				**18,315**	**6.2**	**100.0**

References:

[1] Pechan report to EPA, EPA216a9c, 2000

Table 4-11. Petroleum Refining, SIC 2911[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts: Emissions (tpy)	% of Louisiana Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Industrial Boilers	10200401 10200504	Statewide	Fuel Oil	10,722	3.6	8.3
Industrial Boilers	10300601 10300602 10300603	Statewide	Natural gas	29,419	10.0	22.9
Refinery Process heaters	30600104 30600105	Statewide	Natural gas	56,199	19.1	43.7
Refinery Process heaters	30600103 30600106	Statewide	Oil-Fired	22,950	7.8	17.8
Fluid Catalytic Crackers	30600201	Statewide		9,283	3.1	7.2
Total				**128,573**	**43.6**	**100.0**

References:

1 Pechan report to EPA, EPA216a9c, 2000

Table 4-12. Chemical Manufacturing, SIC 2869[1] and Industrial Organic Chemicals, SIC 2869[1]

Equipment	SCC Codes	Location	Process	2010 NOx Emissions Forecasts: Emissions (tpy)	% of Louisiana Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Chemical Manufacturing, SIC 2869[1]						
Fuel Fired Equipment	30190003	Statewide	Heaters, Incinerators	72	0.0	2.6
Flares, Miscellaneous	30199999	Statewide	Miscellaneous	1,603	0.5	57.4
Chemical Manufacturing	30125099 30125899	Statewide	Alcohols, Aromatics Production	125	0.0	4.5
Chemical Manufacturing	30112502	Statewide	Ethylene Production	23	0.0	0.8
Chemical Manufacturing	30109105	Statewide	Keytone Production	141	0.0	5.1
Chemical Manufacturing	30125002 30125001	Statewide	Methanol Production	485	0.2	17.4
Chemical Manufacturing	30112599	Statewide	Organohalogens	2,019	0.7	72.3
Plastics Production	30101812	Statewide	Polyethylene L.D.	40	0.0	1.4
Total				**2,794**	**0.9**	**100.0**

Table 4-12. Chemical Manufacturing, SIC 2869[1] and Industrial Organic Chemicals, SIC 2869[1]

Equipment	SCC Codes	Location	Process	2010 NOx Emissions Forecasts: Emissions (tpy)	% of Louisiana Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Industrial Organic Chemicals, SIC 2869[1]						
Chemical Manufacturing	30190003 30199990 30125099 30125899 30112502 30109105 30125002 30125001 30112599 30101812	Statewide	Organic Chemical Production	6,614	2.2	40.1
Industrial Boilers	10200501 10200504	Statewide	No.1, No. 2 No. 4and No. 6 Oil	503	0.2	3.0
Industrial Boilers	10200601 10200602 10200603	Statewide	Natural Gas	3,840	1.3	23.3
Reciprocating Engines	20200102 20200401	Statewide	Diesel	173	0.1	1.1
Gas Turbines	20200201	Statewide	Natural Gas	785	0.3	4.8
Process Heaters	30600104 30600105	Statewide	Natural Gas	4,589	1.6	27.8
Total				**16,505**	**5.6**	**100.0**

References:

1 Pechan report to EPA, EPA216a9c, 2000

Applicable State Regulations

Louisiana air regulations apply emission limits by equipment category rather than emissions category. We analyzed the emissions control technologies that apply to SIC categories Natural Gas Transmission (NGT) and Crude Petroleum and Natural Gas (COPNG) together since the same types of equipment predominate in each category.

Natural Gas Transmission (NGT) covers the field processing, compression and transmission of natural gas from production to storage areas. The combustion equipment used includes Natural Gas-Fired Boilers (SCC 10300602 and 10300603) and Natural Gas-Fired Process Heaters (SCC 31000404), but the most important emissions sources listed in the emissions inventory are Natural Gas-Fired Gas Turbines (SCC 20200201), Natural Gas-Fired IC Engines (SCC 20200202), and "Compressors" (SCC 31000203). (The inventory used in this analysis did not specify the type of combustion equipment used to drive these compressors). The most important category is Natural gas-fired IC engines (sometimes described as reciprocating engines), which are expected to produce almost 85% of the NOx emissions from this SIC category in 2010.

The Crude Oil Petroleum and Natural Gas (COPNG) category covers the production of crude petroleum and natural gas, including exploration, drilling, and oil and gas well operation.

Virtually all the NOx from this SIC category in 2010 will be produced by natural gas-fired IC engines.

Table 4-13a summarizes the Louisiana air regulations that currently apply to NGT and COPNG equipment.

Table 4-13a. Regulations for Stationary Gas Turbine and Natural Gas-fired Internal Combustion Engines in Louisiana.

Regulatory Reference: Louisiana Code, Title 33, Environmental Quality, Part III Air, Chapter 22, Section 2201				
Source: Stationary Gas Turbines (Not in electrical service)				
Geographic Area	Applicability	Limits	Exemptions [3]	Percent reduction from uncontrolled levels
Baton Rouge NAA [1]	>5 to 10 MW	0.24 lb/MMBtu	Units <5MW	25
	>10 MW	0.16 lb/MMBtu		50
Region of Influence [2]	>10 MW	0.16 lb/MMBtu	Units <10 MW	50
Rest of State	No limits except, presumably PSD BACT and NSPS when applicable		All units	0
Source: Natural gas-fired IC Engines				
Geographic Area	Applicability	Limits	Exemptions [3]	Percent reduction from uncontrolled levels
Baton Rouge NAA [1]	Lean burn 150-320 hp	10 g/hp-hr	Lean burn engines <150 hp	15
	Lean burn >320 hp	4 g/hp-hr		66
	Rich burn 150-300 hp	2 g/hp-hr	Rich burn engines <150 hp	80
	Rich burn >300 hp	2 g/hp-hr		80
Region of Influence [2]	Lean Burn >1500 hp	4 g/hp-hr	Lean burn engines <1500 hp	66
	Rich burn >300 hp	2 g/hp-hr	Rich burn engines <300 hp	80
Rest of State	No limits except, presumably PSD BACT and NSPS when applicable		All units	0

[1] The Baton Rouge Nonattainment Area consists of the entire parishes of Ascension, East Baton Rouge, Iberville, Livingston, and West Baton Rouge.

[2] The Region of Influence is an area to the north of the Baton Rouge Nonattainment Area that encompasses affected facilities in the attainment parishes of East Feliciana, Pointe Coupee, St. Helena, and West Feliciana.

[3] The prescribed limits do not apply at facilities within the Baton Rouge Nonattainment Area if their affected point sources collectively have the potential to emit less than 25 tons or more per year of NO_x, nor any facility within the Region of Influence if their affected point sources have the potential to emit less than 50 tons or more per year of NO_x. The limits are applicable during the ozone season (May 1-September 30) but do not apply other months. Individual point sources that operate less than 400 hours during the ozone season are exempt. There are a number of other exemptions listed in the rule based on the use of equipment. Finally, facilities have the option of creating a facility-wide averaging plan rather than meeting limits on a unit-by-unit basis.

The Natural Gas Liquids (NGL) category also addresses activities associated with the production and initial field processing of petroleum liquids and natural gas. In addition to gas turbines, IC engines and compressors, the category contains process heaters and industrial boilers. All the equipment is expected to be natural gas-fired in 2010. Table 4-13b summarizes the emission limits that currently apply to process heaters and industrial boilers in Louisiana.

Table 4-13b. Regulations for Natural Gas-fired Industrial Boilers, Process Heaters, and Furnaces in Louisiana.

Regulatory Reference: Louisiana Code, Title 33, Environmental Quality, Part III Air, Chapter 22, Section 2201				
Source: Natural gas-fired industrial boilers				
Geographic Area	Applicability	Limits	Exemptions [3]	Percent reduction from uncontrolled levels
Baton Rouge NAA [1]	>40 to 80 MMBtu/hr	0.20 lb/MMBtu	Units < 40 MMBtu/hr	0
	> 80 MMBtu/hr	0.10 lb/MMBtu		29
Region of Influence [2]	> 80 MMBtu/hr	0.10 lb/MMBtu	Units < 80 MMBtu/hr	29
Rest of State	No limits except, presumably PSD BACT and NSPS when applicable		All units	0
Source: Process heaters and furnaces (Ammonia reformers have less stringent limits)				
Geographic Area	Applicability	Limits	Exemptions [3]	Percent reduction from uncontrolled levels
Baton Rouge NAA [1]	>40 to 80 MMBtu/hr	0.18 lb/MMBtu	Units < 40 MMBtu/hr	0
	> 80 MMBtu/hr	0.08 lb/MMBtu		43
Region of Influence [2]	> 80 MMBtu/hr	0.08 lb/MMBtu	Units < 80 MMBtu/hr	43
Rest of State	No limits except, presumably PSD BACT and NSPS when applicable		All units	0

[1] The Baton Rouge Nonattainment Area consists of the entire parishes of Ascension, East Baton Rouge, Iberville, Livingston, and West Baton Rouge.

[2] The Region of Influence is an area to the north of the Baton Rouge Nonattainment Area that encompasses affected facilities in the attainment parishes of East Feliciana, Pointe Coupee, St. Helena, and West Feliciana.

[3] The prescribed limits do not apply at facilities within the Baton Rouge Nonattainment Area if their affected point sources collectively have the potential to emit less than 25 tons or more per year of NO_x, nor any facility within the Region of Influence if their affected point sources have the potential to emit less than 50 tons or more per year of NO_x. The limits are applicable during the ozone season (May 1-September 30) but do not apply other months. Individual point sources that operate less than 400 hours during the ozone season are exempt. In addition, boilers and process heaters are can also be exempted if their ozone season use factors are below specified levels. There are a number of other exemptions listed in the rule based on the use of equipment. Finally, facilities have the option of creating a facility-wide averaging plan rather than meeting limits on a unit-by-unit basis.

The Petroleum Refining SIC category covers the final processing of crude oil into gasoline, distillate fuels like diesel and fuel oil, and other products. NOx is produced by a variety of combustion equipment. In addition to some of the natural gas-fired equipment discussed above, refineries produce NOx from other fuels like process gas, fuel oil and waste oils. In addition to boilers, process heaters and IC engines, fluid catalytic cracking units (FCC units) can also be a significant source of NOx. FCC units produce NOx from process heaters and catalyst regenerators. The latter are exempt from control in Louisiana. (Section 2201. B. 5. 12). Since Louisiana's NOx emission limits are not fuel specific for the source categories listed above, we assumed that the limits contained in Tables 4-13a and Table 4-13b also apply at refineries.

MISSISSIPPI

Overview

Mississippi is located in the second "ring" of the study area states for the H-36 study and was found in the H-35 study's preliminary findings to have exceeded EPA's initial screening criteria as a potentially significant contributor to 8-hour ozone levels of >85 ppb in all four episodes. The affected non-attainment areas in all episodes were Houston-Galveston and Beaumont-Port Arthur, and the near non-attainment area of Northeast Texas. The H-35 study preliminary results showed an impact of 9.3 ppb maximum 8-hour ozone contribution to the Beaumont-Port Arthur NAA area during the Austin Episode. Based on Mississippi's location and H-35 impacts upon Texas NAAs, we limited to 5 tpd emissions in 1999. Two SIC categories were found to exceed our 6% SIC cutoff criteria – SIC 4911, EGUs, and SIC 4922, Natural Gas Transmission (NGT). A total of 25 sources, including nine EGUs and twelve NGT sources exceeded the 5 tpd criteria.

In 1999, EGUs emitted 81,200 tons of NOx in Mississippi, dropping to 70,500 tons in 2001 base year. NGT facilities emitted 66,700 tons of NOx in 1999. In the 2010 base, all EGUs in Mississippi were projected to emit a 43,200 tons of NOx and all non-EGU point sources a total of 74,400 tons of NOx. Total NOx emissions in Mississippi in 2010 were projected at 287,800 tons. The proposed CAIR allocation for point source NOx in 2010 was initially set at 21,932 tons in the June 4, 2004 SNPRM, and then corrected slightly on July 23, 2004 to 21,007 tons in 2010 and 17,506 tons in 2015.

There are no 1-hour or 8-hour ozone nonattainment areas in Mississippi, or are there any PM2.5 nonattainment areas. Mississippi is not part of the NOx Budget Trading Program (NBP).

Electric Generating Units (EGUs)

EGUs emitted 44.0% of all point source NOx emissions in Mississippi in 1999 and thus offer the greatest potential for emission reductions under the CAIR budget. As noted above, however, they are not subject to the NOx SIP Call.

The Mississippi Commission on Environmental Quality state regulations specifically applying to air pollution and EGUs are covered under rules APC-S-1 to 7. As the state is fully attainment for all of the NAAQS, there does not appear to be any special regulations for emissions of NOx other than the standard Federal requirements such as NSPS for fossil-fuel-fired steam generators, Title V permitting, and Title IV (Acid Rain) programs.

Table 4-14 provides information on emissions, existing and future controls, and locational information for all EGUs that, in 1999, emitted greater than 5 tpd of NOx in Mississippi.

MISSISSIPPI

Table 4-14. Electric Generating Units, SIC 4911.

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[2,3]	New Controls-1999 to 2010 [2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Mississippi	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons					
Baxter Wilson-Entergy-2 units	Warren Co.	21,800	30.9	0	0	0	Oil/Gas	Oil/Gas Early Retirement (O/GER)	NA	NA	NA
Watson Power Plant-MS Power Co-6 units	Harrison Co.	14,600	21.0	14,200	6,300	43.7	Coal(2), Gas(4)	Low NOx Burner		APC-S-1	No
Gerald Andrus PP-Entergy	Washington Co.	10,200	14.5	0	0	0	Gas		NA	NA	NA
Victor Daniel PP-MS Power Co.-2 units	Jackson Co.	11,500	16.3	18,100	8,000	55.6	Coal			APC-S-1	No
RD Morrow PP-So. MS Electric Power Assn.-2 units	Lamar Co.	6,100	8.6	7,800	3,500	24.0	Coal	Low NOx Burner		APC-S-1	No
Chevron Oil Plant-MS Power Co.-5 units	Jackson Co.	2,600	3.7	84	84	0.1	Gas	OGER		NA	No
Rex Brown-Entergy-4 units	Hinds Co.	1,000	1.4	2,800	1,500	12.0	Gas(3)	SCR	NA	APC-S-1	NA
Moselle PP-So. MS Electric Power Assn.-4 units	Jones Co.	900	1.3	0	0	0	Gas		NA	NA	NA
Misc. locations-total 7 units, TVA(3), So. MS (2), Entergy (2)		0	0	0	0	0	Gas(6), Coal(1)		NA	NA	NA
All EGU (SIC 4922) Sources		70,500		43,200							

References:

1. NE1 2001 to IPM-NEEDS Matches, http://www.epa.gov/interstateairquality/pdfs/NEI2001_IPM-NEEDS_Matches.xls
2. Pechan report to EPA, EPA216a9c_2000_Pechan_toEPA
3. Argus SCR Report, May 4, 2004
4. Mississippi Commission on Environmental Quality, Rule APC-S-1 to 7

Discussion

Two of the largest EGUs in 1999-2001, the Wilson and Andrus power plants, are located on the Mississippi River bordering Louisiana and Arkansas, and are therefore the closest large EGU sources to Texas. However, CAIR projections for 2010 indicate that the Wilson plant will be retired and the Andrus plant will switch to gas and apparently have no significant NOx emissions. The remaining major EGUs in Mississippi are either located in the Hattiesburg metropolitan area of southeast Mississippi or along the Gulf Coast. The coal-fired Victor Daniel plant, operated by Mississippi Power, will have increased its NOx emissions from 9,800 tons in 1999 to 18,100 tons in 2010. There are no current plans, per CAIR data, to place any controls upon that facility and thus this would be a potential source to encourage greater controls in the future. The facility is located just north of Pascagoula in the Gulf Coast region of the state. The other major coal-fired EGU emission source, the Watson plant, is also located near the Gulf Coast metropolitan areas and has no plans to upgrade its Low NOx Burner system between now and 2010, per CAIR data. Without further investigation of specific permit limits on the Mississippi EGUs, which is beyond the scope of this project, it would appear that all have minimal NSPS level controls and are therefore less stringently regulated than Texas.

Non-EGUs

General Information

In addition to Electrical Generating Units, only one SIC category, Natural Gas Transmission (# 4911), has sufficient NOx emissions in Mississippi to meet this study's screening criteria for further analysis. Table 4-15 summarizes 2010 emissions forecasts for Natural Gas Transmission (NGT).

2010 Emissions Forecasts

This category covers the field processing, compression and transmission of natural gas from production to storage areas. The NOx emissions inventory for Mississippi lists gas turbines and IC engines (sometimes referred to as reciprocating engines) as the dominant types of equipment in use. IC engines are expected to produce more than 80% of the NOx emissions from NGT in 2010. According to the emissions inventory forecasts, all non-EGU combustion equipment will be natural gas-fired in 2010.

MISSISSIPPI

Table 4-15. Natural Gas Transmission, SIC 4922[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts		
				Emissions (tpy)	% of Mississippi Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Stationary gas turbines	20200201	Statewide	Natural gas	11,556	16.0	83.4
Reciprocating IC engines	20200202	Statewide	Natural gas	2,303	3.2	16.6
Total				**13,859**	**19.2**	**100.0**

References:

[1] Pechan report to EPA, EPA216a9c, 2000

Estimated NOx emissions from Natural Gas Transmission (NGT) in 2010 are 13,859 tons per year, or 19.2% of point source emissions.

Applicable State Regulations

Mississippi has no State regulatory requirements that establish NOx emission limits for non-EGU gas turbines or IC engines. It is possible that some units are controlled because they were subject to federal requirements such as Prevention of Significant Deterioration (PSD) or New Source Performance Standards (NSPS), but the evaluation of individual facilities is not within the scope of this study. It is likely that most NGT equipment is currently uncontrolled.

MISSOURI

Overview

Missouri is located on the outer edge of the study area states for the H-36 study, located nearly 200 miles away at its closest point to Texas. The H-35 study's preliminary findings showed Missouri to have slightly exceed EPA's initial screening criteria as a potentially significant contributor to 8-hour ozone levels of >85 ppb in Texas nonattainment areas for only the Austin episode. The affected non-attainment areas were Houston-Galveston, Dallas-Fort Worth, Victoria, and Austin. Accordingly, we limited our evaluation to point sources that exceeded 10 tpd emissions in 1999. Only one SIC category were found to exceed our 6% SIC cutoff criteria – SIC 4911, EGUs. Twelve EGU sources exceeded the 10 tpd criteria. Only one non-EGU sources emitted over 10 tpd in 1999 in Missouri, a large cement plant in Pike County (SIC #3241).

In 1999, EGUs emitted 310,200 tons of NOx in Missouri, dropping to 150,100 tons in the 2001 base year. In the 2010 base case, all EGUs in Missouri were projected to emit 137,000 tons of NOx and all non-EGU point sources a total of 29,700 tons of NOx. Total NOx emissions in Missouri in 2010 were projected at 363,600 tons. The proposed CAIR allocation for point source NOx in 2010 was initially set at 56,571 tons in the June 4, 2004 SNPRM, and then corrected slightly on July 23, 2004 to 53,918 tons in 2010 and 44,931 tons in 2015.

Missouri has portions of two interstate 1-hour ozone maintenance areas – St. Louis (MO-IL) and Kansas City (MO-KA). Five counties in the St. Louis area are also designated as a moderate 8-hour ozone area. Missouri also is a part of a newly-designated interstate PM2.5 nonattainment area – four counties and the city of St. Louis in Missouri, and four counties in Illinois. Portions of eastern Missouri will be required to comply with the NOx SIP Call in 2007. Missouri was removed from the initial, May 2004 deadline of the NOx SIP call in the US Court of Appeals decision.

Electric Generating Units (EGUs)

EGUs emitted 85.2% of all point source NOx emissions in Missouri in 1999 and thus offer the greatest potential for emission reductions under the CAIR budget. All of the major EGU emitters of NOx are coal-fired units. Air quality regulations in Missouri are contained in Title 10, Division 10 of the Missouri Department of Natural Resources in the State Code of Regulations. Within Division 10, Chapter 2 applies to sources in the Kansas City NAA, Chapter 3 to the out state areas of Missouri, Chapter 4 to Springfield-Greene County, and Chapter 5 to metropolitan St. Louis. Finally, all other requirements for air quality are contained in Chapter 6.

Section 5.510, Control of Emissions of NOx, applies to the EGUs and other boilers in the St. Louis metropolitan region. These apply to power plants in St. Louis City, and in St. Louis, Franklin, St. Charles, and Jefferson counties. Four of the largest twelve EGUs in Missouri are in the St. Louis metropolitan area – one in each of the four counties. The table "1" from the Missouri regulations, shown below, sets the maximum allowable emission rates.

Table 1
Maximum Allowable NO_X Emission Rates for Boilers
(Pounds of NO_X per mmBtu)

Fuel/Boiler Type	Firing Configurations			
	Tangential	Wall	Cyclone	Stoker
Gaseous Fuels Only	0.2	0.2	0.5	-
Distillate Oil	0.3	0.3	-	-
Residual Oil	0.3	0.3	-	-
Coal – Wet Bottom	-	-	0.86	-
Coal – Dry Bottom	0.45	0.5	-	0.5

There are no comparable regulations for NOx emissions in the Springfield or Kansas City area rules.

The Missouri Air Conservation Commission adopted a statewide rule to reduce Oxides of Nitrogen (NOx) emissions from electric generating utilities. Missouri's statewide NOx rule is intended to improve air quality in the St. Louis ozone nonattainment area. Missouri's statewide NOx rule, Section 6.350 of Title 10, Division 10, will reduce the emissions of NOx from electric generating units and establishes a NOx emissions trading program available for use by electric utilities throughout the entire state.

Missouri is also developing new regulations that will apply to major EGUs in the state. The rule will become Section 6.360 - Control of NOx Emissions from Electric Generating Units and Non-Electric Generating Boilers. The purpose of the rules will be to put in place EPA's model trading rules that are contained in the NOx SIP Call. Seventeen EGUs and perhaps five cement kilns in the NOx SIP Call area will be affected. The proposed rule closed comments in January 2005, is expected to be adopted by the state in late April and effective on August 30, 2005.

Table 4-16 provides information on emissions, existing and future controls, and locational information for all EGUs that, in 1999, emitted greater than 10 tpd of NOx in Missouri.

MISSOURI

Table 4-16. Electric Generating Units, SIC 4911.

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[2,3]	New Controls -1999 to 2010 [2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Missouri	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons					
New Madrid PP-AECI-2 units	New Madrid Co.[5]	37,800	25.2	19,100	1,400	10.0	Coal	SCR (2 units, '01)		Prop. 6.360	No
Thomas Hill PP-AECI-3 units	Randolph Co.	22,500	15.0	16,900	7,500	53.2	Coal	Low NOx Burner(1)		Chap 3	No
Sioux PP-Amerien UE-2 units	St. Charles Co.[5]	15,400	10.2	15,600	1,800	12.5	Coal			Sec. 5.510	No
Sibley PP-Aquila-3 units	Jackson Co.	11,800	7.9	11,400	4,400	31.5	Coal			Chap. 2	No
Labadie PP-Ameriin UE-4 units	Franklin Co.[5]	8,600	5.8	16,700	8,000	56.5	Coal			Sec. 5.510	No
Meramac PP-Ameren UE-4 units	St. Louis Co.[5]	9,600	6.4	11,400	5,100	35.9	Coal	Low NOx Burner (1)		Sec. 5.510	No
Montrose PP-KCPL-3 units	Henry Co.	5,900	3.9	5,200	2,300	16.2	Coal	Low NOx Burner (4)		Chap 3	No
Iatan PP-KCPL	Platte Co.	6,900	4.6	6,700	3,000	21.1	Coal	Low NOx Burner (1)		Chap. 2	No
Rush Island PP-Ameren UE-2 units	Jefferson Co.[5]	4,100	2.8	8,000	3,600	25.2	Coal	Low NOx Burner (2)		Sec. 5.510	No
James River PP-City of Springfield-5 units	Greene Co.	4,900	3.3	4,800	1,800	13.1	Coal	Low NOx Burner (3)		Chap. 4	No
Asbury PP-Empire	Jasper Co.	4,800	3.2	3,800	1,400	10.3	Coal			Chap 3	No
St. Joseph PP-St. Joseph P&L	Buchanan Co.	4,100	2.8	No Data Available in CAIR							
All EGU (SIC 4922) Sources		150,100		137,000							No

References:

1. NE1 2001 to IPM-NEEDS Matches, http://www.epa.gov/interstateairquality/pdfs/NEI2001_IPM-NEEDS_Matches.xls
2. Pechan report to EPA, EPA216a9c_2000_Pechan_toEPA
3. Argus SCR Report, May 4, 2004
4. Missouri Department of Natural Resources, Title 10, Division 10
5. Part of NOx SIP Call area

Discussion

The two largest EGUs in 1999 NOx emissions, New Madrid and Thomas Hill, are located in relatively rural areas of the state. Most of the other large EGUs in Missouri are either in the St. Louis or the Kansas City metropolitan areas. With the installation of SCR in 2001, the largest EGU, New Madrid, will reduce NOx emissions from 52,200 tons in 1999 to 19,100 tons in 2010. Thomas Hill and James River plants also have significant reductions between 2001 and 2010. However, one facility, the Labadie power plant in Franklin County near St. Louis, has a major increase in NOx during that time period, from 8,600 tons in 2001 to 16,700 in 2010. Ladabie does not have any current or proposed NOx emission controls and is thus a major candidate for greater reductions. The Sioux and Sibley plants likewise have no current or projected pollution controls and are projected to emit a combined total of 27,000 tons of NOx in 2010 under the CAIR projections. The emission limits for coal-fired power plants in Missouri under current rules range from 0.45 to 0.86 lb/MMBtu, while the most lenient limit in eastern Texas is set a 0.165 lb/MMBtu. Therefore, all current Missouri EGUs are less stringently regulated than comparable facilities in Texas.

The Missouri DNR estimated that in 2004 NOx emissions in the eastern, NOx SIP Call portion of the state to be 42.7% of the total state NOx emissions from EGUs. With the EGUs in eastern Missouri being a part of the NOx SIP Call trading program in May 2007, the sources in the remainder of the state appear more likely to be candidates for additional controls. The projected EGU emissions for 2010 from Missouri EGUs are over 2.5 times the CAIR 2010 budget allocation. This will mean that Missouri must obtain major reductions beyond currently planned controls from both EGUs and non-EGU sources to meet that budget.

Non-EGUs

No SIC categories with 6% or more of the Statewide NOx point source emissions exist in Kentucky.

OKLAHOMA

Overview

Oklahoma is borders on the northern side of Texas and thus is one of the three states having the potential, geographically, to have most significant impacts upon the Texas SIP areas. The closest SIP areas in Texas are the Dallas-Fort Worth NAA and the Northeast Texas NNAA. Its most significant impact upon that region was under the conditions of the Dallas-Fort Worth episode. The H-35 study preliminary results showed an impact of 6.6 ppb maximum 8-hour ozone contribution to the Dallas-Fort Worth NAA and 9.6 ppb to the Northeast Texas NNAA. It also had relatively minor impacts upon those two areas during the Houston-Galveston/Beaumont Port Arthur episode.

Because of the location and impacts of Oklahoma on northern Texas, we evaluated point sources that exceeded 1.5 tpd emissions in 1999. Four SIC categories were found to exceed our 6% SIC cutoff criteria – SIC 1311, Crude Petroleum; SIC 1321, Natural Gas Liquids; SIC 4911, EGUs;

and SIC 4922, Natural Gas Transmission. Fifteen EGUs, 8 NGT sources, 10 NGL sources, and one Crude Petroleum & Natural Gas facility exceed the 1.5 tpd criteria.

In 1999, EGUs emitted 98,900 tons of NOx in Oklahoma, dropping to 86,200 tons in the 2001 base year. In the 2010 base case, all EGUs in Oklahoma were projected to emit 82,100 tons of NOx and all non-EGU point sources a total of 121,000 tons of NOx. Total NOx emissions in Oklahoma in 2010 were projected at 363,100 tons. Oklahoma is not part of the CAIR program and thus does not have a 2010 or 2015 state NOx emission budget.

Oklahoma is attainment for one and 8-hour ozone, and for PM 10 and PM 2.5.

Electric Generating Units (EGUs)

EGUs emitted exactly 50% of all point source NOx emissions in Oklahoma in 1999. As noted above, Oklahoma is not subject to the CAIR program or the NOx SIP Call. Accordingly, all sources of NOx in Oklahoma can be judged against their current regulations and projected control strategies for becoming a potential candidate for further emission reductions.

Air pollution regulations in Oklahoma are addressed under Title 252 of the Department of Environmental Quality, Chapter 100 – Air Pollution Control. The key subchapter affecting EGUs is Subchapter 33 – Control of emissions of NOx. The regulations apply to any new fuel-burning equipment (February 14, 1972 start date) or modification of existing fuel-burning equipment. The rules apply to sources (equipment) that both have a rated heat input of 50 MM Btu/hr or greater, and burns solid fossil, gas, or liquid fuel. Emission limits are as follows:

(a) **Gas-fired fuel-burning equipment.** Nitrogen oxide emissions (calculated as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20lb/MMBtu (86 ng/J) heat input, three-hour average.
(b) **Liquid-fired fuel-burning equipment.** Nitrogen oxide emissions (calculated as nitrogen dioxide) from any new liquid-fired fuel-burning equipment shall not exceed 0.30 lb/MMBtu (129 ng/J) heat input, three-hour average.
(c) **Solid fossil fuel-burning equipment.** Nitrogen oxide emissions (calculated as nitrogen dioxide) from any new solid fossil fuel-burning equipment shall not exceed 0.70 lb/MMBtu (300 ng/J) heat input, three-hour average.

As there are no separate nonattainment areas in Oklahoma, these regulations are part of the overall Oklahoma SIP and thus apply to all sources under the above definitions. Other subchapters that may affect EGUs in Oklahoma include subchapter 3, Air Quality Standards (PSD increments); subchapter 4, NSPS; and subchapter 8, Permits for Part 70 Sources. Section 2 of subchapter 8 defines “affected states” and includes Texas.

Table 4-17 provides information on emissions, existing and future controls, and location information for all EGUs that, in 1999, emitted greater than 1.5 tpd of NOx in Oklahoma.

OKLAHOMA

Table 4-17. Electric Generating Units, SIC 4911.

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[2,3]	New Controls -1999 to 2010 [2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Oklahoma	Emissions tpy	Summer emissions- tons	Peak Summer Day - tons					
Muskogee PP- Oklahoma Gas & Electric (OGE)-4 units	Muskogee Co.	18,800	21.8	23,300	10,500	73.8	Coal (3), Gas (1)	Overfire Air (3 units)		252.100.33	No
Northeastern Plant-Central & South West Services(CSWS)-5 units	Rogers Co.	18,100	21.0	13,700	6,300	45.1	Coal (2), Gas (3)	Low NOx Burner (2), EGR (1-gas)		252.100.33	No
Sooner Power Plant-OGE-2 units	Noble Co.	11,200	13.0	15,000	6,700	46.7	Coal	Overfire Air(2)		252.100.33	No
GRDA PP-Grand River Dam Authority-2 units	Mayes Co.	14,400	16.7	15,300	6,800	47.6	Coal	SMCR(1), Low NOx Burner (1)		252.100.33	No
Hugo PP-Western Farmers Coop (WFC)	Choctaw Co.	2,900	3.4	5,000	2,200	46.7	Coal	Low NOx Burner		252.100.33	No
Comanche PP-CSWS-5 units	Comanche Co.	2,700	3.1	1,000	700	4.9	Gas			252.100.33	No
Seminole PP-OGE-3 units	Seminole Co.	4,300	5.0	600	600	5.4	Gas			252.100.33	No
Tulsa Power Station-CSWS-4 units	Tulsa Co.	4,500	5.2	50	50	0.4	Gas			252.100.33	No
Mustang PP-OGE-6 units	Canadian Co.	2,500	2.9	400	400	3.2	Gas			252.100.33	No
Southwestern Plan t-CSWS-5 units	Caddo Co.	2,000	2.3	300	300	2.8	Gas			252.100.33	No
Riverside PP-CSWS-3 units	Tulsa Co.	500	0.6	500	500	4.1	Gas	Overfire Air (2 units)		252.100.33	No
Anadarko Plant-WFC-6 units	Caddo Co.	72	<0.1	400	300	2.0	Gas	Oil/Gas Early Retirement (O/GER) (2 units)		252.100.33	No
Horseshoe Lake Plant-4 units	Oklahoma Co.	1,600	1.8	2,900	2,900	2.3	Gas			252.100.33	No
Shady Point Plant-AES-2 units	Le Flore Co.	900	1.0	3,700	1,700	11.7	Coal			252.100.33	No
Mooreland Plant-WFC	Woodward Co.	400	0.5	100	100	1.0	Gas			252.100.33	No
All EGU (SIC 4922) Sources		86,200		82,100							

References:

1. NE1 2001 to IPM-NEEDS Matches, http://www.epa.gov/interstateairquality/pdfs/NEI2001_IPM-NEEDS_Matches.xls
2. Pechan report to EPA, EPA216a9c_2000_Pechan_toEPA
3. Argus SCR Report, May 4, 2004
4. Oklahoma Department of Environmental Quality, Title 252, Chapter 100, Subchapter 8-2.

Discussion

The four largest EGUs in Oklahoma, all which were coal-fired or a combination of coal and gas-fired units, made up 78% of the 2010 projected NOx emissions. With the exception of the Northeastern Plant in Rogers County, all will have increased their NOx emissions between 1999 and 2010. These four facilities are certainly candidates for additional NOx control between now and 2010. As Oklahoma is not under the NOx SIP call, has no nonattainment areas for any NAAQS, and the proposed CAIR program does not apply, there is little current incentive for additional controls beyond what are shown in Table 4-17. All EGUs in Oklahoma appear to be less stringently regulated than comparable EGUs in eastern Texas. Gas-fired EGUs in Texas are 42% more stringently regulated and coal-fired EGUs are 325% more stringently regulated in Texas.

The four largest EGUs, noted in previous section, are all located in the northeastern portion of Oklahoma and not too far outside of the Tulsa metropolitan area. One medium-sized EGU, the Hugo power plant, is located in Choctaw County bordering on the Texas northern border. Six of the major power plants in 1999 are now relatively low polluters, entirely gas-fired, and primarily used in the summer months.

Non-EGUs

General Information

In addition to Electrical Generating Units, three SIC categories have sufficient NOx emissions in Oklahoma to meet this study's screening criteria for further analysis. They are Natural Gas Transmission (# 4911), Crude Petroleum and Natural Gas, (# 1311), and Natural Gas Liquids (# 1321). Tables 4-18 through 4-21 below summarize 2010 emissions forecasts for these categories.

2010 Emissions Forecasts

Table 4-18. Natural Gas Transmission, SIC 4922[1]

				2010 NOx Emissions Forecasts		
Equipment	SCC Codes	Location	Fuel Type	Emissions (tpy)	% of Oklahoma Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Stationary gas turbines	20200201	Statewide	Natural gas	1,112	0.9	2.5
Reciprocating IC engines	20200202	Statewide	Natural gas	42,528	35.2	97.5
Total				**43,639**	**36.2**	**100.0**

References:

[1] Pechan report to EPA, EPA216a9c, 2000

Table 4-19. Crude Petroleum and Natural Gas, SIC 1311[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts		
				Emissions (tpy)	% of Oklahoma Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Reciprocating IC engines	20200202	Statewide	Natural gas	13,994	11.6	100.0
Total				**13,994**	**11.6**	**100.0**

References:

1 Pechan report to EPA, EPA216a9c, 2000

Table 4-20. Natural Gas Liquids, SIC 1321[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts		
				Emissions (tpy)	% of Oklahoma Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Stationary gas turbines	20200201	Statewide	Natural gas	844	0.7	4.2
Reciprocating IC engines	20200202	Statewide	Natural gas	19,106	15.8	95.8
Total				**19,950**	**16.5**	**100.0**

References:

1 Pechan report to EPA, EPA216a9c, 2000

Table 4-21. Petroleum Refining, SIC 2911[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts		
				Emissions (tpy)	% of Total Oklahoma Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Industrial Boilers	10200701	Statewide	Petroleum Refinery Gas	2,686	2.2	25.4
Industrial Boilers	10300601	Statewide	Natural gas	555	0.5	5.3
Refinery Process heaters	30600104 30600105	Statewide	Natural gas	1,833	1.5	17.4
Refinery Process heaters	30600106	Statewide	Process Gas-Fired	4,178	3.5	39.6
Fluid Catalytic Crackers	30600201	Statewide		1,308	1.1	12.4
Total				**10,560**	**8.7**	**100.0**

References:

1 Pechan report to EPA, EPA216a9c, 2000

The Crude Oil Petroleum and Natural Gas (COPNG) category covers the production of crude petroleum and natural gas, including exploration, drilling, and oil and gas well operation. It is a smaller source category that is forecast to produce 11.6 % of Oklahoma's non-EGU, point source NOx in 2010. Natural gas-fired IC engines will produce virtually all the NOx from this SIC category.

The Natural Gas Liquids (NGL) category also addresses activities associated with the production and initial field processing of petroleum liquids and natural gas. The category is expected to produce 16.5 % of 2010 non-EGU, point source NOx emissions in 2010. Both gas turbines and IC engines are used, but about 95% of the emissions will be from IC engines.

We can analyze the emissions control technologies that apply to all three SIC categories together since the same types of equipment predominate in each category.

Applicable State Regulations

As noted above, Oklahoma air regulations apply NOx emission limits to "new" fuel burning equipment based on the type of fuel they burn. "New" equipment is defined as any fuel burning source that was installed, altered, replaced or rebuilt after specified applicable dates. Since applicable dates are well in the past (from 1972-1977), we assume that equipment turnover will leave the vast majority of fuel burning equipment that will be in use in 2010 subject to the regulatory limits.

Table 4-22 summarizes the Oklahoma air regulations that currently apply to natural gas-fired gas turbines and IC engines.

Table 4-22. Regulations for Fuel Burning Equipment in Oklahoma.

Regulatory Reference: Oklahoma, Title 252, Department of Environmental Quality, Chapter 100, Air Pollution Control, Section 252:100-33				
Source: Fuel burning equipment, including Gas Turbines and IC Engines				
Geographic Area	Applicability	Limits by fuel type	Exemptions [3]	Percent reduction from uncontrolled levels
Statewide	>50 MMBtu/hr	Natural gas, 0.20 lb/MMBtu	Units <50 MW, units older than 1972-1977, depending on equipment type	38-96% depending on type of equipment
		Liquid fuel, 0.30 lb/MMBtu		
		Solid fuel, 0.70 lb/MMBtu		

The emissions forecasts used in this study do not provide sufficient detail about the size or heat rating of the individual pieces of equipment used to determine the extent to which these regulations control their emissions.

TENNESSEE

Overview

Tennessee is located on the outer edge of the study area states for the H-36 study, located 275 miles away at its closest point and the major EGUs are located even further away. The H-35 study's preliminary findings showed Tennessee to have exceeded EPA's initial screening criteria as a potentially significant contributor to 8-hour ozone levels of >85 ppb in Texas nonattainment areas for the Austin, Dallas-Fort Worth, and Houston-Galveston/Beaumont Port Arthur episodes. There were slight impacts in all but the Corpus Christi Near-NAA in one or more of these episodes. The H-35 study preliminary results showed the largest Tennessee impact as 10.7 ppb maximum 8-hour ozone contribution to the Northeast Texas NNAA during the Houston-Galveston/Beaumont Port Arthur episodes. Due to the distance from Texas, especially for the major NOx emission sources, we limited our evaluation to point sources that exceeded 10 tpd emissions in 1999. Only two SIC categories were found to exceed our 6% SIC cutoff criteria – SIC 4911, EGUs (68.8%) and SIC 4922, NGT (7.9%). Seven EGUs and one non-EGU source exceeded the 10 tpd criteria. The non-EGU source was a chemical plant (SIC 2869) located in the far northeastern corner of the state.

In 1999, EGUs emitted 186,800 tons of NOx in Tennessee, dropping to 156,800 tons in the 2001 base year. In the 2010 base case, all EGUs in Tennessee were projected to emit 102,800 tons of NOx and all non-EGU point sources a total of 78,000 tons of NOx. Total NOx emissions in Tennessee in 2010 were projected at 505,000 tons. The proposed CAIR allocation for point source NOx in 2010 was initially set at 47,739 tons in the June 4, 2004 SNPRM, and then corrected slightly on July 23, 2004 to 45,193 tons in 2010 and 37,661 tons in 2015.

Tennessee has six 8-hour ozone NAAs. They are: Chattanooga (TN-GA Interstate, two TN counties, Subpart 1); Clarksville-Hopkinsville, TN-KY (Interstate, one TN county, Subpart 1); Johnson City-Kingsport-Bristol (Intrastate, 2 counties, Subpart 1); Knoxville (Intrastate, all or portions of seven counties, Subpart 1); Memphis, TN-AR (Interstate, one TN county, Marginal); and Nashville (Intrastate, five counties, Subpart 1). The Subpart 1 (Basic) NAAs have to meet the standard by 2009 (with 5-year extension possible) and the Marginal NAA areas must meet the standard by 2007. The Memphis area petitioned in July 2004 to be reclassified to Marginal from Moderate. EPA approved the request in September 2004 and the area must now meet the 8-hour ozone standard by 2007 under the Marginal Area regulatory deadlines. The 8-hour ozone NAA counties in Tennessee are all under a 1-hour maintenance SIP as well. Tennessee also has three remaining one-hour ozone NAAs – Knoxville (1 county), Memphis (1 county), and Nashville (5 counties). Tennessee has two PM2.5 NAAs – Chattanooga Interstate (TN-GA, one TN county) and Knoxville Intrastate (all or portions of 5 counties). Tennessee joined the Ozone Transport Commission (OTC) states in May, 2004 to be a part of the NOx Budget Trading Program (NBP).

Electric Generating Units (EGUs)

EGUs emitted 68.8% of all point source NOx emissions in Tennessee in 1999 and thus offer the greatest potential for emission reductions under the CAIR budget. As Tennessee is an active partner in the NOx Budget Trading Program, EGUs are primarily regulated through NOx allocation allowances as assigned by the US EPA and approved in the Tennessee SIP. Tennessee sources are regulated under rules of the Tennessee Department of Health and Tennessee Department of Environment and Conservation. Chapter 1200-3-27 addresses NOx emissions. The NBP requirements are detailed in subchapter 1200-3-27-.06. In general, the state allocates 95.7% of its NOx allowances to EGUs in the state trading program. Through a series of formulae, the remaining allowances may be allocated to non-EGU sources.

Table 4-23 provides information on emissions, existing and future controls, and location information for all EGUs that, in 1999, emitted greater than 3,650 tons per year of NOx in Tennessee.

TENNESSEE

Table 4-23. Electric Generating Units, SIC 4911.

Plant	Location	2001 NOx Emissions[1]		Projected 2010 NOx Emissions[2]			Fuel Type	Pollution Controls[2,3]	New Controls-1999 to 2010 [2, 3]	Applicable Rules[4]	Rules as Stringent as Texas?
		Emissions tpy	% EGU source emissions in Tennessee	Emissions tpy	Summer emissions-tons	Peak Summer Day - tons					
Cumberland PP-TVA—2 units	Stewart Co.	51,200	32.6	30,100	2,200	15.3	Coal		SCR ('03, 2 units	1200-3-27-.06	NA-NBP
Kingston PP- TVA – 9 units	Roane Co.	26,200	16.7	11,200	800	5.7	Coal	SCR (1 unit)	SCR (04, 6 units), (05, 2 un.)	1200-3-27-.06	NA-NBP
Johnsonville PP – TVA – 10 coal units, 20 gas turbine units	Humphreys Co.	21,400	13.6	17,300	6,900	47.5	Coal	Low NOx Burner (4), Other (6)		1200-3-27-.06	NA-NBP
Allen PP – TVA - 3 coal units, 20 gas turbine units	Shelby Co.	19,400	12.4	14,200	1,000	7.2	Coal		SCR (02, 2 units), (04, 1 un.)	1200-3-27-.06	NA-NBP
Gallatin PP – TVA – 4 coal units, 8 gas turbine units	Sumner Co.	11,000	7.0	13,700	6,000	42.0	Coal	Low NOx Burner (4 un.)		1200-3-27-.06	NA-NBP
Bull Run PP – TVA – 1 unit	Anderson Co.	17,300	11.0	6,500	500	3.3	Coal		SCR (04)	1200-3-27-.06	NA-NBP
John Sevier PP – TVA – 4 units	Hawkins Co.	10,200	6.5	9,700	4,300	29.5	Coal	Low NOx Burner (4 un.)		1200-3-27-.06	NA-NBP
All EGU (SIC 4922) Sources		156,800		102,800							

References:

1. NE1 2001 to IPM-NEEDS Matches, http://www.epa.gov/interstateairquality/pdfs/NEI2001_IPM-NEEDS_Matches.xls
2. Pechan report to EPA, EPA216a9c_2000_Pechan_toEPA
3. Argus SCR Report, May 4, 2004
4. Tennessee Dept. of Environment and Conservation, Rule 1200-3-27-.06

Discussion

All seven major EGUs in Tennessee are operated by the Tennessee Valley Authority (TVA). They are part of the NOx SIP Call's NOx Budget Trading Program and thus must reduce emissions per their allowance and the statewide allocation. When, and if the CAIR is implemented, additional reductions by 2010 and 2015 will be necessary. Four of these EGUs currently have installed, or are in the process of constructing, SCRs on all or some of their units. Tennessee sources of NOx must be reduced to 45,193 tpy by 2010 under the proposed CAIR allocations. This budget is only 44% of the projected 2010 EGU emissions of NOx, which will mean the state will need to require considerable additional controls on their EGUs if they decide to take all of these additional reductions from power generation. Those sources that appear to have the highest potential for additional air pollution control would likely be the three remaining major EGUs that do not use SCR for control, but currently use Low NOx Burners. The Gallatin power plant near Nashville is a prime candidate as its emissions are projected by CAIR to increase during the 2001 to 2010 period. Gallatin, along with the Johnsonville PP, also have the two highest summer day NOx emissions (42.0 tpd and 47.5 tpd, respectively) and thus may be prime contributors to summertime ozone levels.

Four of the major EGUs are located in or near major Tennessee metropolitan areas. Both the Kingston and Bull Run power plants are near Knoxville. The Allen power plant is in Memphis. And, the rapidly growing Nashville metropolitan area contains the Gallatin power plant. Cumberland, Johnsonville, and John Sevier power plants are in relatively rural areas.

As all EGUs in Tennessee are potentially subject to the NBP allocations, it is not possible within the scope of this study to determine whether existing controls are more stringent than Texas rules.

Non-EGUs

General Information

In addition to Electrical Generating Units, only one SIC category, Natural Gas Transmission (# 4911) has sufficient NOx emissions in Tennessee to meet this study's screening criteria for further analysis. Table 4-24 summarizes 2010 emissions forecasts for Natural Gas Transmission.

2010 Emissions Forecasts

This category covers the field processing, compression and transmission of natural gas from production to storage areas. The NOx emissions inventory for Tennessee lists a few large industrial boilers and a number of gas turbines in use, but the predominate type of equipment, with over 90% of the NOx emissions, is IC engines (sometimes referred to as reciprocating engines). According to the emissions inventory forecasts, all combustion equipment will be natural gas-fired in 2010. Estimated NOx emissions from Natural Gas Transmission (NGT) in 2010 are 15,680 tons per year, or 20.1% of non-EGU, point source emissions.

Table 4-24. Natural Gas Transmission, SIC 4922[1]

Equipment	SCC Codes	Location	Fuel Type	2010 NOx Emissions Forecasts		
				Emissions (tpy)	% of Tennessee Non-EGU Point Source NOx Emissions	Equipment category's share of SIC NOx emissions
Stationary Gas Turbines	20200201	Statewide	Natural gas	1,062	1.4	6.8
Reciprocating IC engines	20200202 20200252	Statewide	Natural gas	14,618	18.7	93.2
Total				**15,680**	**20.11**	**100.0**

References:

1 Pechan report to EPA, EPA216a9c, 2000

Applicable State Regulations

Tennessee has not traditionally imposed equipment-specific, statewide NOx emission limits for non-EGU gas turbines or IC engines. In 1993 however, Tennessee required major sources of NOx in selected counties[1] to install RACT level controls by mid-1995. In addition, Tennessee is subject to the 1998 NOx SIP Call and has been assigned state emission reduction budgets that it must meet in phases. Part of that SIP call requires the control of certain large IC engines by 2007. (69 FR 77, April 21, 2004, p 21634). To meet its obligations under the SIP Call, Tennessee adopted a NOx Trading Program in 2001 that assigned individual budgets to EGU's >25MW as well as to other combustion units with rated heat capacities >250 MMBtu/hour. These requirements are summarized in Table 4-25.

Table 4-25. Regulations for Internal Combustion Engines and Gas Turbines in Tennessee.

Regulatory Reference: Tennessee Department Of Environment and Conservation, Bureau Of Environment, Division Of Air Pollution Control, Chapter 1200-3-27, Nitrogen Oxides				
Sources: IC Engines and gas turbines				
Geographic Area	Applicability	Limits	Exemptions	Percent reduction from uncontrolled levels
Davidson, Rutherford, Sumner, Williamson, or Wilson County	"Stationary sources" that emit or have the potential to emit 100 tons per year of NOx	Reasonably available control technology (RACT) for NOx [1]	Sources < 100 tons per year; a process emission source or fuel burning installation which emits or has a PTE < 1 ton per year; Sources that do not operate between April 1 and October 31.	53-95% depending on equipment

1 Davidson, Rutherford, Sumner, Williamson, or Wilson County

Regulatory Reference: Tennessee Department Of Environment and Conservation, Bureau Of Environment, Division Of Air Pollution Control, Chapter 1200-3-27, Nitrogen Oxides				
Rest of State	Non-EGU units with a design heat rating >250 MMBtu/hr	80-90% NOx reduction, calculated per 40 CFR 96.42, alternate compliance methods allowed.	All units <250 MMBtu/hr. Other exemptions and conditions as described in 40 CFR 96.	80-90

[1] Since compliance was required by mid-1995, control requirements reflect RACT technology of the mid-1990's.

It is not within the scope of this study to determine which, if any individual NGT units are subject to the emissions trading rule. If any units are subject to the rule, they will either have to reduce their emissions by 80-90% or acquire sufficient allocation credits from other sources.

GULF OF MEXICO

Under the federal Clean Air Act, the Mineral Management Service (MMS) of the Department of Interior has the authority to regulate outer continental shelf (OCS) air emissions in the central and western Gulf of Mexico. According to a recent (2004) emissions inventory, a variety of sources in the Gulf of Mexico produce roughly 215,000 tons per year of NOx. This total includes approximately 165,500 tons per year from oil and gas production activities (including 78,049 tpy from platforms), and another 50,000 tons from non-oil and gas activities (Gulfwide Emission Inventory Study for the Regional Haze and Ozone Modeling Efforts, Final Report, Table 8-3, p. 8-14, Prepared under MMS Contract 1435-01-00-CT-31021, by Eastern Research Group, Inc., October 2004). While there were numerous sources of NOx in the Gulf of Mexico from oil and gas field exploration, the largest individual source in this inventory emitted about 2.1 tons per day of NOx.

In 1995 the MMS completed an air quality modeling study that was mandated by the 1990 Clean Air Act Amendments. The study estimated off shore emissions, collected other required input data and evaluated four multi-day ozone episodes in Texas and Louisiana that occurred in 1993. According to the MMS, the study concluded that OCS emissions "do not play a significant role in ozone violations in Houston and Beaumont-Port Arthur in eastern Texas, and Baton Rouge and Lake Charles in Louisiana (Air Regulations Affecting Exploration and Production: MMS Regulation of Offshore Activities in the Gulf of Mexico, Richard E. Defenbaugh, p. 7).

MMS regulations require NOx controls on new exploration and development facilities under some circumstances (30CFR 250.44 to 250.46). If modeling shows that project emissions would increase on shore concentrations above specified thresholds, BACT or other controls can be required.

Our preliminary look at emissions of NOx did not indicate emissions impact greater than our criteria for the study. However, this is an area that further study may be necessary to assure that the Federal regulations are contributing their fair share in reducing the impact upon eastern Texas NAA areas.

5. NOx REGULATIONS IN EASTERN AND CENTRAL TEXAS

Overview

Section 5 provides information on the current Texas regulations for categories of point sources that have been examined in our eight study area states. While we did examine the regulations for both the major SIP areas and intervening counties in Central and Eastern Texas, we did not perform an in-depth analysis of major point source emissions in this area as this data is already readily available at TCEQ. Rule information identified in Section 5, along with that uncovered in our examination of the eight study area states in Section 4 was extensively used in our Comparison of Regulatory Requirements (Section 7).

We defined the study area counties for Central and Eastern Texas as follows:

- All counties in the three major SIP 8-hour non attainment areas (NAA) of Eastern Texas (Dallas-Fort Worth, Houston-Galveston, and Beaumont-Port Arthur)
- The five county Tyler-Longview-Marshall near non attainment area (NNAA)
- Adjacent and intervening counties to these four SIP areas that had a point source with NOx emissions of over one ton per day in 1999

Appendix A lists these counties by the above categories.

We then performed a geographical and size distribution of EGU and non-EGU point sources for each of the above categories, based on the 1999 National Emission Inventory. That information and distribution is summarized in Appendix B. In summary, the Central and East Texas study area counties contain 36 EGUs and 91 non-EGU point sources that emitted one ton or more of NOx in 1999. The Houston-Galveston Area had by far the largest number of those point sources – 38% of the EGUs and 51% of the non-EGUs.

The H-35 study's preliminary findings showed Texas, not at all surprisingly, to be the largest contributor of any state to 8-hour ozone levels in every NAA and near-NAA in all but two episodes in Texas. Those two exceptions had Louisiana contributing more ozone to the Beaumont-Port Arthur NAA in the Dallas-Fort Worth episode, exceeding the initial screening criteria for NAAs and NNAAs.

In 1999, EGUs emitted 421,200 tons of NOx in all of Texas, dropping to 324,600 tons in the 2001 base year. In the 2010 base case, all EGUs in Texas were projected to emit 200,900 tons of NOx and all non-EGU point sources a total of 523,800 tons of NOx. Total NOx emissions in Texas in 2010 were projected at 1,599,500 tons. The proposed CAIR allocation for point source NOx in 2010 was initially set at 224,314 tons in the June 4, 2004 SNPRM, and then corrected slightly on July 23, 2004 to 233,447 tons in 2010 and 194,539 tons in 2015.

Texas has four 8-hour ozone NAAs: Dallas-Fort Worth, Houston-Galveston, Beaumont-Port Arthur San Antonio. Dallas-Fort Worth and Houston-Galveston are classified as Moderate, Beaumont-Port Arthur as Marginal, and San Antonio is a Subpart 1 area. There were not any PM2.5 areas designated as nonattainment in Texas and, only El Paso was a PM10 nonattainment area. Texas is not part of the NOx Budget Trading Program (NBP).

Electric Generating Units (EGUs)

EGUs emitted 48.6% of all point source NOx emissions in Texas in 1999, the largest individual SIC category for NOx emissions in the state. Regulations for point source NOx in Texas are contained in the Texas Administrative Code in Title 30, Part 1, Chapter 117 – Control of Air Pollution from Nitrogen Compounds. Subchapter B contains regulations for combustion at major sources, with Division 1 of that subchapter for EGUs in ozone NAAs. Division 2 specifically covers the control of emissions from NOx for EGUs in Central and Eastern Texas outside of non-attainment areas. Table 5.1 summarizes the emission limits for EGU boilers and gas turbines in three study area NAAs and the remainder of East and Central Texas.

Table 5-1. Current NOx Regulations on Electrical Generating Units in Central and East Texas.

Area	Electric Power Boilers			Industrial Boilers	Stationary Gas Turbines
	Coal-fired	Fuel oil-fired	Other-gas/liquid		
Beaumont/P. Arthur	All: NTE 0.10 lb/MMBtu	All: NTE 0.10 lb/MMBtu	All: NTE 0.10 lb/MMBtu		
Dallas-Fort Worth	Large DFW system sources: NTE 0.033 lb/MMBtu. Small DFW, NTE 0.06 lb/MMBtu.	Large DFW system sources: NTE 0.033 lb/MMBtu. Small DFW, NTE 0.06 lb/MMBtu.	Large DFW system sources: NTE 0.033 lb/MMBtu. Small DFW, NTE 0.06 lb/MMBtu.		
Houston/Galveston	NTE 0.045 (tangential-fired) or 0.050 (wall-fired)lb/MMBtu	NTE 0.045 (tangential-fired) or 0.050 (wall-fired) lb/MMBtu	NTE 0.030 lb/MMBtu	NTE 0.030 lb/MMBtu	NTE 0.032 lb/MMBtu
East and Central Texas	NTE 0.165 lb/MMBtu		NTE 0.14 lb/MMBtu		NTE 0.14 to 0.15 lb/MMBtu, depending on subject to Texas Utility Code

Non-EGUs

General Information

In addition to Electrical Generating Units, only two other SIC categories have NOx emissions greater than the 6% screening criteria that we used in our 8-state study – SIC 2869, Industrial Organic Chemicals (10.1%) and SIC 2999, Petroleum Refining (7.6%). These percentages are for the proportion of statewide NOx emissions and are likely much greater in the Central and Eastern Texas study area. Since we are not evaluating Texas NOx emissions in this study, it was not prudent to spend resources refining the SIC category proportions to our specific study area.

Control Requirements

The point sources NOx emissions and potential control strategies have been intensely reviewed and analyzed in the many rounds of SIP development over the last 15 years. Control requirements were also reviewed and described in earlier, related work by ENVIRON. Since our purpose in describing Eastern Texas NOx rules is limited to providing a basis for a rough comparison of Texas requirements with parallel requirements in contributing states, we have only included control information on the types of equipment that was reviewed in priority SIC categories in other states. This information is summarized in Table 5-2 and will appear again in Section 7 where additional documentation and references are provided.

Table 5-2. Emission Controls Required in Texas for Equipment Used in Non-EGU, High Priority SIC Categories that exist in the 8-state study area

Equipment Type	Size Range (MW)	Typical Texas Emission Limit (lb/MMBtu)	Most Stringent Texas Emission Limit (lb/MMBtu)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)
Natural Gas Fired Turbines	1 to 5		0.26	0	19
	> 5 to 10	0.15	0.15	53	53
	>10	0.15	0.03	53	90

Equipment Type	Size Range (hp)	Typical Texas Emission Limit (g/hp-hr)	Most Stringent Texas Emission Limit (g/hp-hr)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)
Natural Gas -Fired IC Engines-Lean Burn	150 to 320		0.5	0	96
	>320	2	0.5	83	96
Natural Gas -Fired IC Engines-Rich Burn	150 to 300		0.5	0	95
	>300	2	0.5	80	95

Equipment Type	Size Range MMBtu/hr	Typical Texas Emission Limit (lb/MMBtu)	Most Stringent Texas Emission Limit (lb/MMBtu)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)
Natural Gas-Fired Industrial Boilers	>40 - 80	0.1	0.1	29	29
	>80	0.1	0.1	29	29

Table 5-2. (concluded) Emission Controls Required in Texas for Equipment Used in Non-EGU, High Priority SIC Categories.

Equipment Type	Size Range MMBtu/hr	Typical Texas Emission Limit (lb/MMBtu)	Most Stringent Texas Emission Limit (lb/MMBtu)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)
Natural Gas-Fired Process Heaters and Furnaces	>40 - 80	0.08	0.08	43	43
	>80	0.08	0.08	43	43

Texas' NOx regulations follow the traditional pattern of imposing a range of reduction requirements that tend to be more stringent for larger sources and for nonattainment areas like Houston which have more difficult air quality problems.

6. CONTROL TECHNOLOGY AND COST EFFECTIVENESS

This section provides a brief overview of the technologies that are used to reach the levels of control identified by the existing regulations in each state as compared to those required by the state of Texas. The costs of these technologies are also presented in terms of the dollars per ton of oxides of nitrogen (NOx) reduced. The information provided is very general, but allows a comparison of the control technologies required in Texas and other states. The three states immediately adjacent to Texas, i.e., Louisiana, Arkansas, and Oklahoma, are the focus of our EGU control technology analysis as the other five states have all or many of their EGUs participating in the NOx SIP Call cap-and-trade program. The information is provided as a range because the level of control and the associated cost depends on several factors including the size of the equipment, the amount of time the equipment is operated and the ability to retrofit the equipment with the various control technologies.

The technologies investigated for point sources are shown in Table 6-1.

Table 6-1. Summary of stationary source control measures: potential reduction, and cost effectiveness.

Source Category	Size	NO_x Control Method[1]	Emissions Reductions (Percent)	Cost Effectiveness[2] ($/ton NO_x)
Utility Boilers-Coal-Fired	200 MW	SNCR	85 – 90	$705 - $1,670[6]
	330 MW	SCR	85 - 90	$760 - $3,430[6]
Utility Boilers-Oil and Gas-Fired	200 MW	SNCR	85 – 90	$1,200 - $5,450[6]
	330 MW	SCR	85 - 90	$1,200 - $5,450[6]
Industrial Boilers	330 MW	SCR	85 - 90	$4,830 to $6,880[3]
	>80 MMBtu/hr	SCR	50 - 80	$3,040 to $5,350[3]
	>40-80 MMBtu/hr	SNCR	50 - 70	$960 to $1,450[3]
	>80 MMBtu/hr	SNCR	50 - 70	$960 to $1,450[3]
Process Heaters and Furnaces	>40-80 MMBtu/hr	SNCR	50 -60	$2,130 to $13,500[3]
	>80 MMBtu/hr	SNCR	50 -60	$2,130 to $13,500[3]
Gas Turbines	<1 MW	DLNC	60 - 70	$154 to $1,060[3]
	> 5 to 10 MW	LNB	84	$1,403[4]
	>10 MW	SCR	90	$3,580 to $10,800[3]
Natural Gas-Fired IC Engines-Lean Burn	>50 hp	SCR	90	$12,000 to $35,000[3]
	150 to 320 hp	SCR	90	$3,000 to $8,500[3]
	>320 hp	SCR	90	$3,000 to $8,500[3]
Natural Gs-Fired IC Engines-Rich Burn	150 to 300 hp	SNCR	80 -90	$1,000 to $7,400[5]
	>300 hp	SNCR	80 -90	$1,000 to $7,400[5]

[1] Acronyms; LNB (Low NOx Burners), SNCR (Selective Noncatalytic Reduction), SCR (Selective Catalytic Reduction), DLNC (Dry Low NOx Combustors), Water Inj (Water Injection)
[2] The range of cost-effectiveness is primarily a factor of how much a unit is used. See Appendices E and F for further detail.
[3] Emission Factor from Alternative control Techniques (ACT) Document, NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers, March 1994
[4] AirControlNET, Documentation Report v.3.2, September 2003, E.H. Pechan & Associates, Inc.
[5] Alternative Control Technique Document, Stationary Reciprocating Engines, EPA, pp. 2-46 and 2-51.
[6] Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers, Table S-2b, SNCR for coal-fired units and Table S-2a, SCR for coal-fired units.

The resources available to this study do not permit 1) a detailed comparative analysis that looks at individual emission limits, applicability thresholds, exemptions, optional provisions etc. nor 2) revising neighbor states emissions inventories to reflect "Texas-level controls."

Electric Utility Boilers

The majority of emissions from utility boilers are produced by coal-fired power plants. Many of these units are equipped with overfire air (combustion controls) and Low NOx burners. Secondary controls, which include methods such as selective catalytic reduction (SCR) and non-selective catalytic reduction (SNCR) techniques, have not been employed on these units. Use of these controls will provide most of the emission benefits in the subject states. SCR has the largest utility boiler experience base of any secondary control technology. There are many such installations now operating successfully in the U.S. and elsewhere throughout the world. SCR has been found to be "…technically viable for all U.S. coal-fired facilities."[1] EPA clearly corroborates the viability of SCR retrofits on EGUs in its CAIR proposal. Emission reductions being achieved are generally 85 percent to 90 percent.

The economic viability of using SCR at any given site can only be determined after a careful analysis specific to the site and including the type and size of boiler, the congestion at the site and the age of the units. The cost for SCR is fairly reasonable for today's ozone nonattainment areas. Depending on the capacity factor of the unit (a factor of how much the unit is used), the type of unit and the size of the boilers, the cost-effectiveness to achieve 85-90 percent levels of control range for coal-fired boilers range from $760 to $3,430 per ton of NO_x reduced.

Electric Utility Gas Turbines

SCR control techniques have been widely used in simple cycle gas turbines and almost exclusively in combined cycle gas turbines including turbines located in the states examined in this study. As a result, we have not included these units in our analysis of areas where significant additional reductions can be achieved. It should be noted, however, that SCR retrofits will often require the use of additional space at a facility for control equipment and support equipment, such as ammonia storage tanks. There are many applications of SCR for both oil and gas fired units operating successfully in the U.S. and elsewhere in the world. Reductions of 85 percent to 90 percent are achievable. Again, add-on control equipment can sometimes be difficult depending on the space limitations at a given facility, or at a given unit.

Industrial Boilers and Heaters

Boilers and heaters were primarily found in the natural gas process industry (SIC 1321) and the petroleum refining industry (SIC 2869). These units typically burn commercial grade natural gas and have significant emissions of NOx, particularly when uncontrolled. Control technology was focused on units in two size ranges: 40 to 80 MMBtu/hr and greater than 80 MMBtu/hr which represent the size of boilers and heaters that are typically controlled in the region of study.

[1] Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers, Northeast States for Coordinated Air Use Management, June 1998.

Units that are smaller than 10 MMBtu/hr range from small commercial water heaters to residential water heaters.

There are a variety of controls that can be applied to boilers and heaters to reduce NO_x emissions. For most applications, cost-effective methods of reducing NO_x from boilers and furnaces in this size range[DLC1] have [RAF2]focused on two methods. These are selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR). SNCR technology has been used on hundreds of industrial boilers firing a wide range of fuels. SNCR tends to become less effective at lower baseline levels of uncontrolled NOx. For this reason, many gas-fired units find other approaches such as SCR to be more effective. SCR is more expensive to install than SNCR but has been used to control hundreds of utility and industrial boilers in Japan, and Germany, and several coal and gas-fired boilers in the United States. Implementation of add on control equipment can sometimes be difficult, or even impossible, due to space limitations at a given facility, or at a given unit. This is particularly true for package units, which are less adaptable to such additions. However, the costs to reduce NO_x are fairly reasonable for today's ozone nonattainment areas. One factor to consider is the capacity factor (a factor of how much the unit is used) of the unit being considered for control. A higher capacity factor will result in a lower (better) cost-effectiveness.

Gas Turbines

Engines in the natural gas industry are used primarily to power compressors used for pipeline transportation, field gathering (collecting gas from wells), underground storage and gas processing plan applications. Emission control technologies for gas turbines include Dry Low NOx Combustors (DLNC), Low NOx Burners (LNB) and Selective Catalytic Reduction (SCR) and are commonly used. DLNC is a gas-turbine technology that enables gas turbine combustors to produce low NOx emission levels with diluents (such as water or steam) or catalysts. SCR is the exhaust treatment technology most widely used on gas turbines[2]. It is required on many new installations in severe non-attainment areas such as the South Coast Air Quality Management District in California and many other areas of the country. Over 150 commercial installations of SCR on gas turbines in the United States and nearly all gas turbines in new Combined-Cycle Gas Turbine power plants use this technology.

Internal Combustion Engines

These engines are used in a wide variety of applications ranging from hospitals and schools to many industrial applications but primarily are used in the natural gas industry and the petroleum refining industry for those states included in this study. The sizes of engines range from 35 horsepower to 1340 horsepower and primarily burn natural gas or diesel fuel, but also burn gasoline and other fuels. The analysis for IC engines was focused on natural gas-fired engines. Control techniques depend on the type of engine (2-stroke, 4-stroke, and rich or lean burn). Rich burn stationary IC engines are most commonly used at natural gas production facilities.

[2] Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Northeast States for Coordinated Air Use Management, December 2000.

Because NOx is the primary pollutant of significance emitted from pipeline compressor engines, applications of SCR and NSCR have been used to reduce NOx emissions by 80 to 90 percent. SNCR is the most commonly used NOx reduction method for rich-burn engines. While it is one of the most efficient technologies to reduce NOx emissions, SCR is still yet to be widely demonstrated or used in the US to reduce NOx emissions from NG, lean-burn stationary IC engines because of the challenge in maintaining high level of control while minimizing ammonia slip under variable load conditions. The proven low emission combustion (LED) technology is still the widely used technology for NG, lean-burn IC engines. However, SCR vendors indicated that the shortcoming has been corrected by new generation of technology that includes improved catalyst, PEMS/CEMS feedforward system control, and use of urea as the reductant agent.[3]

Cost-Effectiveness

Based on the technologies evaluated and the potential emission reductions, we evaluated the costs and cost effectiveness for each of the point source strategies. The cost-effectiveness is summarized in Table 6-1.

The range of cost-effectiveness is primarily a factor of how much a unit is used. A higher capacity factor for a given control will result in a lower cost-effectiveness than on the same unit with a lower capacity factor. For example, the Northeast States for Coordinated Air Use Management (NESCAUM) recently reported that SCR technology could reduce NO_x emissions on a natural gas-fired utility boiler by 85% or more (0.2 lb/MMBtu to 0.03 lb/MMBtu).[4] The cost effectiveness to achieve this level of control ranges from $1,200 to $5,500 per ton of NO_x reduced with a capacity factor ranging from 10 to 80 percent. For turbines, dry low-NO_x combustors (DLNC) applied to turbines in the 75MW size range results in cost-effectiveness in the range of $200/ton with a high capacity factor (95 percent) to $1,100/ton for seasonal use and a low capacity factor (45 percent).[5]

[3] Stationary Reciprocating Internal Combustion Engines: Updated Information on NOx Emissions and Control Techniques, Revised Final Report to US EPA, EC/R Incorporated, Chapel Hill NC, September 2000.
[4] Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers, NESCAUM and MARAMA, June 1998.
[5] Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, NESCAUM, December 2000.

7. COMPARISON OF REGULATORY REQUIREMENTS

In this section, we summarize our key findings on comparative regulatory requirements in the eight study states (Arkansas, Alabama, Kentucky, Louisiana, Mississippi, Missouri, Oklahoma, and Tennessee) with those of Texas, both for NAAs and more "typical" attainment/NNAAs of eastern Texas.

The stringency of any state's regulations tends to reflect the type and severity of its air quality problems. While many of the contributing states have areas exceeding the 8-hour national ozone standard, and several had persistent 1-hour standard violations, their problems have not been as severe as the ozone problem Texas has faced in the Houston-Galveston and Dallas-Fort Worth NAAs.

EGU Regulation Comparisons

Table 7-1 is a summary table that compares NOx control requirements in states that have been shown to contribute significantly to ozone problems in Central and Eastern Texas with Texas regulations. Table 7-1 only addresses the types of EGU equipment in use in the three states that border the northern and eastern sides of Texas and thus have the potential, geographically, to most significantly affect the Texas SIP areas.

We chose to look at the emissions from fossil fuel-fired steam generating units (utility boilers) as these plants have the most significant emissions of NOx. Many of the EGUs are combined cycle or simple cycle gas turbines that burn natural gas and have applied advanced control technology. As a result, emissions from these types of units were not included in the table. Examining permits for specific EGUs in Arkansas, Louisiana and Oklahoma that appear to have the potential for additional controls of air pollution is beyond the scope and resources of this initial study but is recommended for a future study. It should also be pointed out that in most of the other five study areas states, all or portions of those states are under the NOx SIP Call and budgets. EGUs in those states are frequently opting to install SCR on all or some of their units to meet their emission allocations under the NOx SIP Call. More information on all EGUs and their control equipment can be found in the extensive tables in Section 4.

The stringency of any state's regulations tends to reflect the type and severity of its air quality problems. While most of the contributing states have areas exceeding the 8-hour national ozone standard, and several had persistent 1-hour standard violations, their problems have not been as severe as the ozone problem Texas has faced in both Houston and Dallas. For comparison purposes we have chosen to show both the reductions required by the more stringent regulations in effect in those two areas as well as those that represent more typical limitations such as the East Central area of Texas.

Table 7-1 provides only a rough comparison of the relative stringency of state rules for affected equipment. It should be pointed out that this comparison is based on an analysis that did not look at each individual utility boiler and as such does not reflect that some of these plants may have existing controls that reduce emissions beyond typical uncontrolled emission levels. In general, however most- of these units typically are not controlled or employ the less effective combustion controls rather than post combustion controls that achieve significantly greater emissions reductions.

Table 7-1. Summary Comparison of Eastern Texas and Contributing State NOx Requirements on Equipment Used in Electrical Generating Unit (SIC 4911) Category.

State	Equipment of Interest	Applicability Thresholds (lb/MMBtu)	Percent Emission Reduction Required by State Regulation	Emission Reduction Required by Typical Texas Regulation (a)	Percent Emission Reduction Required by Most Stringent Texas (b)
Arkansas (included in CAIR proposal; not part of NOx Budget Program)					
Arkansas regulations require new and modified sources meet federal NSPS for Fossil Fuel-Fired Steam Generators	Coal-fired	> 40 to 80	0	63	86
		>80	0	63	93
	Number 6 Fuel	>40 to 80	0		63
		> 80	0		84
	All Others (gaseous or liquid)	>40 to 80	0	13	63
		>80	0	33	84
Louisiana (included in CAIR proposal; not part of NOx Budget Program)					
Louisiana's limits for steam generating system boilers apply in the Baton Rouge NAA	Coal-fired	> 40 to 80	0	63	86
		>80	53	63	93
	Number 6 Fuel	>40 to 80	0		63
		> 80	14		84
	All Others (gaseous or liquid)	>40 to 80	0	13	63
		>80	52	33	84
Louisiana's limits for electric power generating system boilers apply in the Region of Influence.	Coal-fired		0	63	86
		>80	53	63	93
	Number 6 Fuel		0		63
		> 80	14		84
	All Others (gaseous or liquid)		0	13	63
		>80	52	33	84
Oklahoma (Not included in CAIR proposal; not part of NOx Budget Program)					
Oklahoma rules apply to sources (equipment) that both has a rated heat input of 50 MM Btu/hr or greater, and burns solid fossil, gas, or liquid fuel.	Coal-fired	> 40 to 80	0	63	86
		>50	0		86
		>80	0	63	93
	Number 6 Fuel	>40 to 80	0		86
		>50	0		86
		> 80	0		93
	All Others (gaseous or liquid)	>40 to 80	0	13	86
		>50	0		86
		>80	0	33	93

(a) Most typical Texas requirement is represented by the regulations in effect in East and Central Texas
(b) Texas requirements include the more stringent requirements required for the Dallas-Fort Worth Attainment Demonstration SIP.

As with the non-EGU equipment appropriate caution should be taken indrawing final conclusions, however, the table can be read to indicate that the Texas requirements we used for comparison are generally more stringent than the parallel requirements in Arkansas, Louisiana and Oklahoma.

Non-EGU Regulation Comparisons

To keep the Houston situation from biasing this comparison, we chose to exclude the very stringent regulations that Texas adopted in the Houston 1-Hour Attainment Demonstration SIP. Specific regulations for the various ozone SIP areas of Texas, including Houston-Galveston, were outlined in the previous section of this report.

Table 7-2 compares NOx control requirements in states that have been shown to contribute significantly to ozone problems in Eastern Texas with Texas regulations. Table 7-2 only addresses the types of equipment in use in the non-EGU SIC categories that we described for each state in Section IV of this report. The comparisons can be extended to the same types of equipment in other SIC categories, but not other types of equipment.

Table 7-2 provides only a rough comparison of the relative stringency of state rules for affected equipment. Readers should be aware of several important limitations that are inherent in constructing side-by-side comparisons of complex state rules. The structures of the various state regulations are not consistent. They use different types or applicability thresholds and different cutoffs. They describe emission limits in different units, and apply different definitions and exemptions. Many requirements are seasonal and apply only to parts of a state. To construct a side-by-side comparison it is necessary make a number of simplifying assumptions and unit conversions. In some cases we had to describe control requirements in wide ranges to reflect variability within a state. Readers should read the explanatory notes carefully and, if more explanation is necessary, review the tables and footnotes in Appendices E and F.

Table 7-2. Summary Comparison of Eastern Texas and Contributing State NOx Requirements on Equipment Used in High Priority, Non-EGU, SIC Categories.

State	Equipment of Interest	Applicability Thresholds	Percent Emission Reduction Required by State Regulation	Percent Emission Reduction Required by Texas (a)
Alabama				
	Natural Gas Fired Turbines, size in MW	0 to 5	0	0
		5 to 10	0	53
		>10	0	53
Alabama IC engine control requirements apply only in the northern counties subject to the NOx SIP Call and apply only to those sources that emitted >1 ton per year during a baseline period.	Nat gas-fired IC engines - lean burn, size in MMBtu/hr	>50	0	0
		150 to 320	0-83	0
		>250	0-83	0
		>320	0-83	83
	Nat gas fired IC engines, - rich burn, size in MMBtu/hr	150 to 300	0-83	0
		>250	0-83	0
		>300	0-83	80

State	Equipment of Interest	Applicability Thresholds	Percent Emission Reduction Required by State Regulation	Percent Emission Reduction Required by Texas (a)
Arkansas				
Arkansas has no state regulations that apply to these categories	Nat gas-fired IC engines - lean burn, size in MMBtu/hr	>50 150 to 320 >250 >320	0 0 0 0	0 0 0 83
	Nat gas fired IC engines, - rich burn, size in MMBtu/hr	150 to 300 >250 >300	0 0 0	0 0 80
Kentucky No Non-EGU SIC Categories Analyzed				
Louisiana				
Louisiana's gas turbine limits apply in the Baton Rouge NAA and the Region of Influence. No controls are required in the rest of the state.	Natural Gas Fired Turbines, size in MW	<5 > 5 MW to 10 > 10	0 0-25 0-50	0 53 53
Louisiana's IC engine limits apply in the Baton Rouge NAA and the Region of Influence. No controls are required in the rest of the state.	Nat, gas-fired IC Engines - lean burn, sizes in hp	150 to 320 >320	0-15 0-66	0 83
	Nat. gas-fired IC engines - rich burn, size in hp	150 to 300 >300	0-80 0-80	0 80
Louisiana's industrial boiler limits apply in the Baton Rouge NAA and the Region of Influence. No controls are required in the rest of the state.	Natural gas-fired Industrial Boilers, size in MMBtu/hr	>40 - 80 >80	0 0-29	29 29
Louisiana's process heater limits apply in the Baton Rouge NAA and the Region of Influence. No controls are required in the rest of the state.	Natural gas-fired Process heaters, size in MMBtu/hr	>40 - 80 >80	0 0-43	43 43
Mississippi				
Mississippi has no state regulations that apply to these categories	Natural Gas Fired Turbines, size in MW	<5 > 5 to 10 >10	0 0 0	0 53 53
	Nat gas-fired IC engines - lean burn, size in MMBtu/hr	>50 150 to 320 >250 >320	0 0 0 0	0 0 0 83
	Nat gas fired IC engines, - rich burn, size in MMBtu/hr	150 to 300 >250 >300	0 0 0	0 0 80

State	Equipment of Interest	Applicability Thresholds	Percent Emission Reduction Required by State Regulation	Percent Emission Reduction Required by Texas (a)
Missouri (No Non-EGU SIC Categories Analyzed)				
Oklahoma				
Regulations apply statewide. Liquid and solid-fueled "fuel burning equipment" have less stringent limits	Natural Gas Fired Turbines, size in MW	<5	0	0
		> 5 to 10	0	53
		>10	38	53
	Nat gas-fired IC engines - lean burn, size in MMBtu/hr	>50	96	0
		150 to 320	96	0
		>320	96	83
	Nat gas fired IC engines, - rich burn, size in MMBtu/hr	150 to 300	95	0
		>300	95	80
Tennessee				
Tennessee requires RACT on sources with a PTE > 100 tons per year in part of the state, and 80-90% reduction from sources >250 MMBtu/hr in the rest of the state. The limits listed for units < 250 MMBtu/hr would not apply to sources with permit limits or other conditions that limit PTE below 100 tons per year.	Natural gas-fired turbines, size in MW	<1	0	0
		> 5 to 10	0	53
		>10	0	53
		>50	53	53
		>75	80-95	53
	Natural Gas -Fired IC Engines-Lean Burn, size in MMBtu/hr	>50	0	0
		150 to 320	80-95	0
		>250	80-95	0
		>320	80-95	83
	Natural Gas -Fired IC Engines-Rich Burn, size in MMBtu/hr	150 to 300	80-95	0
		>250	80-95	0
		>300	80-95	80

(a) For purposes of this table, Texas requirements do not include the more stringent requirements required for the Houston Attainment Demonstration SIP.

With appropriate caution, the table can be read to indicate that the attainment area Texas requirements we used for comparison are generally more stringent than the parallel requirements in Arkansas, Louisiana and Mississippi, but appear somewhat less stringent than those in Oklahoma. Alabama and Tennessee have less stringent requirements for some types of equipment, but are more stringent than Texas for other categories. No comparison is made for rules in Missouri or Kentucky because no non-EGU source categories exceeded the thresholds for review.

8. CONCLUSIONS

Introduction

Estimates of the contributions of NO_x emissions from upwind states to high ozone events in eastern Texas prepared under a previous study (the H-35 study) suggest that reductions of NO_x from these states could be expected to contribute to reductions in the frequency and severity of exceedances of the ambient ozone standard in Texas. The present study (the H-36 study) has built upon this result by examining current (2001) and projected future (2010) NO_x emission levels from the largest sources of NO_x in the upwind states and comparing emission control regulations applicable to these types of sources in Texas with those of the upwind states. Taken together, results of the H-35 and H-36 studies, while subject to future refinement and a number of key caveats as described in detail below, provide support for the conclusion that opportunities exist for additional NO_x emission reductions in a number of upwind states which would result in air quality improvements in the ozone nonattainment and near-nonattainment areas of eastern Texas. Additional, more detailed analyses will be needed to pinpoint the specific NO_x sources representing the best opportunities for emission reductions and to quantify the expected air quality benefits and costs associated with any such reductions.

Our H-36 study involved considerable research and analysis of various data sources and provides HARC with a good screening of the various emission trends, specific point sources, current and future regulations and control strategies, and potential cost-effectiveness of additional control measures. While the limited resources for this study did not provide the source-by-source analysis necessary to pinpoint specific emission reductions that might occur from applying Texas-level controls to each of the eight states in our study area, we believe that sufficient information has been developed here to conclude that significant emission reductions can be achieved in at least some neighboring states.

The remainder of this section summarizes our statewide emission findings (Table 8-1) and highlights our conclusions regarding control technologies, cost-effectiveness, and inter-state regulation comparisons. Finally, we list some specific areas that should be considered for additional research and investigation in support of any efforts which may be undertaken to convince the states that impact the Texas ozone attainment problem to take additional measures to reduce their respective NOx emissions.

Summary of NOx Point Source Emission Findings

ENVIRON employed a variety to data sources to analyze and project future NOx emissions in the 8-state study area. By far the greatest source of data was the U.S. Environmental Protection Agency's consistent, ongoing compilations of emission data from point, area, and mobile sources. While the most recent nationwide database for all sources is the 1999 National Emissions Inventory, the extensive effort by the Agency during the past two years to develop the Clean Air Interstate Rule (CAIR) has resulted in reasonably detailed projections of 2001, 2010, and 2015 emission levels for these various categories of sources.

Section 4 of this report contains extensive data on EGU and non-EGU emissions from point sources. In general, EPA's data is more detailed, and perhaps more accurate, for EGUs than for non-EGUs – partially due to the fact that CAIR is focused on a cap-and-trade program for EGU emissions. Table 8-1 summarizes this information by State, and identifies several specific EGUs and non-EGU source categories which may be considered likely candidates for further control. Emissions of NOx from point sources in two states immediately adjacent to eastern Texas – Oklahoma and Louisiana – comprise 35% of all the emissions from the 8-state study area. Of the six other states included in our study, three are on the outer boundaries of the study area and participate in the NOx SIP Call cap-and-trade program. Emissions from sources in these three states are less likely to impact ozone attainment in Texas compared to the other study area states. EGU emissions from the adjacent state of Arkansas represent a large fraction of total NO_x emissions in that state (73%); several large coal-fired power plants in Arkansas have no substantial controls planned.

As noted in Table 8-1, two states located close to Texas, Oklahoma and Mississippi, have significant sources of EGU NOx emissions and are not part of the NOx Budget Trading Program. These EGUs appear to be prime candidates for further control based on analysis of the more detailed information in Section 4.

A major finding of our study is the large contribution of non-EGUs to total NOx point source emissions under the 2010 base case scenario in Louisiana. Nevertheless, while EGUs only contribute 14% of the total NOx point source emissions in the 2010 projections, they are not covered by the NOx Budget Trading Program and the four large EGUs identified in Table 8-1 appear to be prime candidates for potential additional emissions reductions. Furthermore, since three of these EGUs are located outside of the Baton Rouge regulatory area, the non-SIP area regulations for East and Central Texas for coal-fired EGUs if applied to these facilities would result in a 63% reduction of emissions from these sources. However, these sources are not the only potential candidates for additional NO_x control in Louisiana: non-EGU point sources in the state should be examined in more detail, as they consist of 86% of all the NOx point source emissions projected by EPA in 2010. Several SIC categories of non-EGUs are projected to be particularly large NOx emissions sources in 2010: (1) Natural gas transmission, 80,700 tpy, 62% larger than all Louisiana EGU emissions; and (2) Petroleum refining, 128,600 tpy, 2.6 times the emissions as EGUs. Tables 4-8 through 4-12 in Section 4 provide more details on these very significant non-EGU emissions, and Appendix G (to be provided with a later draft of this report) will provide specific information about the larger non-EGUs in Louisiana (and other states in the study area). We also found that projected NOx emissions are generally projected to decrease less from non-EGUs than from EGUs during the 1999 to 2010 period thus offer some opportunities for additional emission reductions.

Key Findings on Control Technology

The most important control technology for EGUs is Selective Catalytic Reduction (SCR). There are many such installations now operating successfully in the U.S. and elsewhere throughout the world and SCR was found in at least one leading study "…to be *technically* viable for all U.S. coal-fired facilities" (emphasis added; see summary of cost effectiveness results below).[1] SCR control techniques have been widely used in simple cycle gas turbines and almost exclusively in combined cycle gas turbines including sources in the states included in this study. There are a

[1] NESCAUM, Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers, June 1998, p. 5.

variety of controls that can be applied to boilers and heaters to reduce NO_x emissions. We focused our control technology examination on two types of emission controls - selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR). SNCR technology has been used on hundreds of industrial boilers firing a wide range of fuels. SNCR tends to become less effective at lower baseline levels of uncontrolled NOx. For this reason, many gas-fired units find other approaches such as SCR to be more effective.

Table 8-1. Summary of 2010 point source NOx emissions by state.

State	Total Point Source NOx (tons)[2]	CAIR Allocation (tons)	EGUs		Non-EGUs		Candidate Sources for Further Control and 2010 Emissions[1]
			Emissions (tons)	% total NOx	Emissions (tons)	% total NOx	
Alabama	217,500	64,359	134,100	61	83,400	39	Barry PP-22,400 tpy, 6 coal-fired units, 3 Low NOx burner controls and one planned SCR. Extending NOx SIP call controls to IC engines but impact on emissions highly uncertain.
Arkansas	71,100	23,537	52,500	73	18,600	27	White Bluff PP-22,300 tpy, 2 coal-fired units; Independence PP-20,800 tpy, 2 coal-fired, Low NOx burner controls. No SCR planned for either source. 2010 CAIR inventory appears to miss a number of uncontrolled sources at natural gas transmission facilities.
Kentucky	230,700	73,710	195,500	84	34,800	16	ShawneePP-19,900 tpy, 10 coal-fired units, 6 with Low NOx burner controls and non SCR planned
Louisiana	346,900	50,783	49,800	14	297,100	86	Dolet Hills-11,600 tpy, 1 coal-fired unit, Low NOx burner controls; Big Cajun 2 - 21,200 tpy, 3 c-f units, Low NOx burners; Rodemacher-8,900 tpy, 1 c-f unit, Low NOx burners; Nelson PP-6,300 tpy, 1 c-f unit. Extensive non-EGU emissions. No NOx controls on non-EGU sources outside Baton Rouge nonattainment area and it's "Region of Influence."
Mississippi	117,600	21,007	43,200	36	74,400	64	Victor Daniel PP-18,100 tpy, 2 c-f units, no controls; Watson PP-14,200 tpy, 2 c-f units, Low NOx burners
Missouri	166,700	53,918	137,000	82	29,700	18	LabadiePP-16,700 tpy, 4 c-f units, no controls; Sioux PP-15,600 tpy, 2 c-f units, no controls; Sibley PP-11,400 tpy, 3 c-f units, no controls
Oklahoma	203,100	NA	82,100	40	121,000	60	Muskogee-23,300 tpy, 3 c-f units, Overfire Air; Northeastern PP-13,700 tpy, 2 c-f units, Low NOx burners; Sooner PP-15,000 tpy, 2 c-f units, Overfire; GRDA PP-15,300 tpy, 2 c-f units, 1 SNCR, 1 Low NOx burner controls. Has control requirements for non-EGU sources but impact on emissions uncertain.
Tennessee	180,800	45,193	102,800	56	78,000	44	Gallatin-13,700 tpy, 4 c-f units, Low NOx burners; Johnsonville-17,300 tpy, 10 c-f units, 4 Low NOx

1. See Section 4 for more details on these and other EGU sources. For non-EGU sources, see Appendix G.
2. 2010 base case emissions developed for CAIR proposal

SCR is the exhaust treatment technology most widely used on gas turbines. It is required on many new installations in severe non-attainment areas such as the South Coast Air Quality Management District in California and many other areas of the country. Over 150 commercial installations of SCR on gas turbines in the United States and nearly all Combined-Cycle Gas Turbine power plants use this technology.

Our analysis of IC engines was focused on natural gas-fired engines. NO_x control techniques depend on the type of engine (2-stroke, 4-stroke, and rich or lean burn). Rich burn stationary IC engines are most commonly used at natural gas production facilities and SNCR is the most commonly used NO_x reduction method for such engines. Recent technological advances have lead to the development of SCR systems suitable for use on lean-burn natural gas fired IC engines.

Key Findings on Cost Effectiveness

Our investigation of cost effectiveness of the various control technologies was limited to published data and research; findings are shown in Table 6-1 of Section 6. Depending on the capacity factor of the unit (a factor of how much the unit is used), the type of unit, and the size of the boilers, the cost-effectiveness to achieve 85-90 percent levels of control range for coal-fired boilers range from $760 to $3,430 per ton of NO_x reduced. These costs for SCR are well within the range accepted in many U.S. ozone nonattainment areas.

Comparison of Regulations in the Eight Study Area States with Texas

A key product of this study was the examination of the various state regulations for high priority SIC and SCC categories of NOx emitting sources and comparison of the stringency of these regulations with those of both a “typical” attainment area in eastern Texas as well as the more stringent regulations in the Houston-Galveston and Dallas-Fort Worth NAAs. While in theory this might seem relatively straightforward, in practice there are serious limitations that are inherent in constructing side-by-side comparisons of complex state rules. The structures of the various state regulations are not consistent; they use different types or applicability thresholds and different cutoffs; they describe emission limits in different units, and apply different definitions and exemptions; and many requirements are seasonal and apply only to parts of a state. To construct a side-by-side comparison, it is necessary make a number of simplifying assumptions and unit conversions. In some cases we had to describe control requirements in wide ranges to reflect variability within a state.

With this preface in mind, we constructed two tables (see Section 7, Table 7-1 for EGU regulations and Table 7-2 for non-EGU regulations) to make these rough comparisons. We limited our comparison of regulations for EGUs to the three adjacent states, Oklahoma, Arkansas, and Louisiana, as most EGUs in the other 5 states were a part of the NOx SIP Call and thus are currently implementing various emission allocation and cap-and-trade strategies. Results shown in Table 7-1 suggest that the Texas EGU requirements we used for comparison are generally more stringent than the parallel requirements in Arkansas, Louisiana and Oklahoma.

For non-EGUs, and with appropriate caution, the results shown in Table 7-2 suggest that the Texas ozone attainment area requirements we used for comparison are generally more stringent than the parallel requirements in Arkansas, Louisiana and Mississippi, but appear somewhat less stringent than those in Oklahoma. Alabama and Tennessee have less stringent requirements for some types of equipment, but are more stringent than Texas for other categories.

Areas for Additional Research and Investigation

Throughout the report we have noted the various limitations within this study that have prevented us from conducting a more in-depth analysis of some of the relevant regulations and specific source control options. If the state of Texas should decide, based on the screening analysis in this report and other important policy considerations, to pursue a specific strategy to "encourage" adjacent states to tighten their regulations as a part of a region-wide effort to lower ozone levels, a more specific and focused study will need to be conducted. Such a study would build upon selected findings from this report. The limitations discussion in Section 2 provides much of the substance for further study, but we are noting here some of the more obvious areas for future research.

- Examine specific operating permits for high-emitting sources in the study area, specifically in Oklahoma, Louisiana, and Arkansas. The emission unit controls need to be evaluated.
- Track and evaluate the impact of upcoming rules and legislation that affect decisions by Texas to encourage greater pollution control measures in adjacent states. Specifically, evaluate impacts of the Clear Skies revisions to the 1990 CAA and/or the final CAIR that may be published as soon as late March if the Clear Skies legislation does not progress.
- Examine the state emission inventories (not just the EPA versions) in much greater depth to determine the categories subject to the various state emission limits for specific sources.
- Determine the actual emission reductions that would occur in state "x" by applying Texas rule "y" to those sources.
- Identify those sources that have controlled beyond the "typical uncontrolled" levels that were in their original permit approvals.
- Evaluate the feasibility of applying control technology to additional equipment in source categories beyond those that were identified as high-priority categories in our study.[2]
- Examine which non-EGUs in the NOx SIP Call states are subject to the emission trading rules.
- Further examine emission inventories and control measures employed in the offshore oil production platforms and operations in the Gulf of Mexico to obtain a more accurate analysis of potential emissions reductions.

[2] Besides EGUs, only SICs which contributed at least 6% of statewide total NOx emissions and/or included at least five or more "major" sources (using different criteria defining a "major" source in each state) were included in our analysis (see Section 2 and Appendix D).

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Appendix A

Eastern and Central Texas Counties Included in Study Area

Dallas-Ft. Worth 8-hour Ozone NAA	Houston-Galveston 8-hour Ozone NAA	Beaumont-Port Arthur 8-hour Ozone NAA	Tyler-Longview-Marshall NNAA	Other counties that have NOx point sources over 1 t/day
Collin	Brazoria	Hardin	Gregg	Angelina
Dallas	Chambers	Jefferson	Harrison	Brazos
Denton	Fort Bend	Orange	Rusk	Cass
Tarrant	Galveston		Smith	Cherokee
Ellis	Harris		Upshur	Fannin
Johnson	Liberty			Grayson
Kaufman	Montgomery			Grimes
Parker	Waller			Henderson
Rockwall				Jasper
				Lamar
				Marion
				Matagorda
				Panola
				Titus
				Van Zandt
				Wood

Appendix B

Geographical Distribution of Central and Eastern Texas Point Sources By Size Cutoff and EGU vs. Non-EGU

Area	Data Year	Data Source	> 1 t/day		> 1.5 t/day		> 2 t/day		> 5 t/day	
			EGU	Non-EGU	EGU	Non-EGU	EGU	Non-EGU	EGU	Non-EGU
Dallas-F.W.	1999	EPA-NEI	8	8	8	6	7	5	4	2
T-L-M NNAA	1999	EPA-NEI	3	6	3	4	3	2	3	1
HGA	1999	EPA-NEI	14	47	13	39	12	37	8	15
BPA	1999	EPA-NEI	1	16	1	14	1	12	1	5
Other Cos.	1999	EPA-NEI	10	14	8	9	7	8	6	3
Totals			36	91	33	72	30	64	22	26

Note: Texas sources limited to HGA, BPA, DFW, and T/L/M Non and Near Non attainment Area counties, and very large point sources in adjacent counties

NEI = National Emissions Inventory, USEPA

Appendix C

Point Source Distribution by Study Area State

STATE	Data Yr	Total EGUs	Total Non-EGU	> 1 t/day		>1.5t/day		>5 t/day		> 10 t/day		Top SIC - No. Fac.
				EGU	Non-EGU	EGU	Non-EGU	EGU	Non-EGU	EGU	Non-EGU	
Alabama	1999	9	17					9	17	8	5	EGU, NGT, Cement, Pulp
Arkansas	1999	7	18	NA	NA	7	19	4	7	3	2	NGT - 15
Kentucky	1999	16	2							16	2	EGU
Louisiana	1999	19	133	19	133	19	101	13	25	8	8	Chem, EGU, Refining, NGT
Mississippi	1999	9	16					9	16	5	5	NGT - 32. Pulp, Cement
Missouri	1999	12	1							12	1	EGU
Oklahoma	1999	15	35	NA	NA	15	36	12	5	8	0	NGT - 33, Ref, fertilizer, NG
Tennessee	1999	7	1							7	2	NGT-12. Pulp, Chem, Expl.
Texas	1999	36	91	36	91	33	72	22	26			EGU, Chem., Pet. Refine.
Totals		130	314	NA	NA	74	228	69	96			

Note: Texas sources limited to HGA, BPA, DFW, and T/L/M Nonattainment counties, and very large point sources in adjacent counties

FER = Facilities Emissions Report

NGT = Natural Gas Transmission

Appendix D

Priority SIC Categories of Point Sources for Review of Regulatory and Emission Impacts

The following table contains our first and second SIC categories for reviewing existing and potential regulations, as well as estimating emission reductions from CAIR and NOx SIP Call actions by 2010. The data was obtained from EPA's 1999 National Emission Inventory (NEI) data base. The 2002 data base is not fully quality assured as yet.

We determined the priority categories by examining two factors – the percentage of the State's total NOx emission inventory contained in the particular SIC, and the number of large point sources (indicated at top of each column of data). We have decided to evaluate point sources of over 1.5 tons per day in the three states that are immediately adjacent to eastern Texas (Louisiana, Arkansas, and Oklahoma). The next cut-off level for major point sources was set at 5 tons per day and was applied to Mississippi and the Gulf (MMS) sources. Finally, the remaining states that H35 screening has identified as potentially significant contributions to the 8-hour ozone levels in one or more nonattainment areas of Texas are evaluated in column 3 with a 10 ton per day cutoff level (Alabama, Kentucky, Missouri, and Tennessee).

We then identified the highest priority SIC categories to evaluate the regulations and emission reductions using the criteria of the SIC having at least 6% of the statewide NOx emissions and/or five or more major sources (using cutoff criteria) of NOx emissions. While there were numerous sources of NOx in the Gulf of Mexico from oil and gas field exploration, the largest individual source emitted about 2.1 tons per day of NOx. Total Gulf NOx emissions from platforms were 78,049 tons per day.

SIC	Activity	> 1.5 t/day (LA, AR, OK)		>5 tpd (MS, GULF)		>10 tpd (AL,KY, MO, TN)	
		# Sources	%States' NOx	# Sources	%States' NOx	# Sources	%States' NOx
1311	Crude Petroleum & Nat. Gas	5	6.5				0.4
1321	Natural Gas Liquids	17	5.2		5.0		
1382	Oil & Gas Field Exploration			0	100.0		
2061	Raw Cane Sugar	0	0.4				
2421	Saw Mills and Planing	0	0.2		0.8		0.1
2611	Pulp Mills	4	1.6	1	2.0	1	0.7
2621	Paper Mills exc. Bldg. Paper	7	3.2		0.6	3	2.7
2631	Paperboard Mills	5	1.2		0.8		0.4
2812	Alkalies and Chlorine		0.1		0.2		
2813	Industrial Gases	2	0.5				
2816	Inorganic Pigments			1	1.8		
2819	Industrial Inorg, Chemicals, NEC	5	1.1		0.3		0.3
2821	Plastics Materials & Resins	3	1.9		0.2		0.2
2824	Organic Fibers, Noncellulosic	1	0.2				
2865	Cylic Crudes & Intermediates	1	0.2				
2869	Industrial Org. Chemicals, NEC	13	6.4			1	2.1
2873	Nitrogenous Fertilizers	9	2.2	1	2.0		0.1
2895	Carbon Black	3	0.9				0.1
2911	Petroleum Refining	16	6.4	1	2.7	1	0.6
2999	Petrol. and Coal Products, NEC	2	0.5		0.1		
3211	Flat Glass	1	0.3				0.4
3221	Glass Containers	3	0.5				
3229	Pressed and Blown Glass, NEC	1	0.1				0.2
3241	Cement, Hydraulic	4	1.1		0.9	2	3.1
3274	Lime						0.9
3295	Minerals, Ground or treated	1	0.2		0.1		0.2
3312	Blast Furnaces & Steel Mills	1	0.3		0.1		0.7
3731	Ship Building & Repair	0			0.6		
4911	Electric Generating Units	41	40.0	9	44.0	44	76.3
4922	Natural Gas Transmission	48	16.0	12	36.2	2	6.0
4925	Gas Products	1	0.2				
4941	Water Supply	1	0.2				
4953	Waste Incineration	2	0.4				0.1
9611	Space Research & Technology				0.4		
	Note: No sources of >2.1 tpd in Gulf from oil platforms/exploration						

Appendix E

EGU Calculations

Louisiana

Electric Power Generating System Boilers: Baton Rouge Nonattainment Area

Category	Maximum Rated Capacity (MMBtu/hr)	Louisiana Emission Limit (lb/MMBtu)	Typical Texas Emission Limit (lb/MMBtu)	Most Stringent Texas Emission Limit (lb/MMBtu)	Average Uncontrolled Emissions[1] (lb/MMBtu)	Emission Reduction Required by Louisiana Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Coal-fired	> 40 to 80	0.50	0.165	0.06	0.44	0	63	86	SNCR	85 – 90	$705 - $1,670[2]
	>80	0.21	0.165	0.033	0.45	53	63	93	SCR	85 - 90	$760 - $3,430[2]
Number 6 Fuel	>40 to 80	0.30		0.06	0.16	0		63	SNCR	85 – 90	$1,200 - $5,450[2]
	> 80	0.18		0.033	0.21	14		84	SCR	85 - 90	$1,200 - $5,450[2]
All Others (gaseous or liquid)	>40 to 80	0.20	0.140	0.060	0.16	0	13	63	SNCR	85 – 90	$1,200 - $5,450[2]
	>80	0.10	0.140	0.033	0.21	52	33	84	SCR	85 - 90	$1,200 - $5,450[2]

[1] Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers

[2] Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers, Table S-2b., SNCR for coal-fired units and Table S-2a., SCR for coal-fired units and gas-fired units-
oil-fired units assumed to have same cost-effectiveness as gas-fired units

Oklahoma and Arkansas

Electric Power Generating System Boilers: Baton Rouge Nonattainment Area

Category	Maximum Rated Capacity (MMBtu/hr)	Oklahoma and Arkansas Emission Limit[3] (lb/MMBtu)	Typical Texas Emission Limit (lb/MMBtu)	Most Stringent Texas Emission Limit (lb/MMBtu)	Average Uncontrolled Emissions[1] (lb/MMBtu)	Emission Reduction Required by Oklahoma and Arkansas Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Coal-fired	> 40 to 80		0.165	0.06	0.44	0	63	86	SNCR	85 – 90	$705 - $1,670[2]
	>50	0.70			0.44	0		90	same	same	same
	>80		0.165	0.033	0.45	0	63	93	SCR	85 - 90	$760 - $3,430[2]
Number 6 Fuel	>40 to 80			0.06	0.16	0		63	SNCR	85 – 90	$1,200 - $5,450[2]
	>50	0.30			0.16	0		72	same	same	same
	> 80			0.033	0.21	0		84	SCR	85 - 90	$1,200 - $5,450[2]
All Others (gaseous or liquid)	>40 to 80		0.140	0.060	0.16	0	13	63	SNCR	85 – 90	$1,200 - $5,450[2]
	>50	0.20			0.16	0		81	same	same	same
	>80		0.140	0.033	0.21	0	33	84	SCR	85 - 90	$1,200 - $5,450[2]

[1] Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers

[2] Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers, Table S-2b., SNCR for coal-fired units and Table S-2a., SCR for coal-fired units and gas-fired units-
oil-fired units assumed to have same cost-effectiveness as gas-fired units

[3] Emissions limits apply only to new or modified units and represent the NSPS for fossil fuel-fired steam generators

Appendix F

Non-EGU Calculations

Emission Control Technology Assessment-Alabama

Equipment Type	Size Range MMBtu/hr	Alabama Emission Limit[6] (g/hp-hr)	Typical Texas Emission Limit (g/hp-hr)	Most Stringent Texas Emission Limit (g/hp-hr)	Uncontrolled Emissions[1] (lb/hp-hr)	Uncontrolled Emissions[1] (gm/hp-hr)	Emission Reduction Required by Alabama Regulation[5] (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas - Fired IC Engines- Lean Burn	>50	N/C			0.026	11.8	0			SCR	90	$12,000 to $35,000[3]
	150 to 320	N/A		0.5	0.026	11.8	83		96	SCR	90	$3,000 to $8,500[3]
	>250	N/A					83			SCR	90	$3,000 to $8,500[3]
	>320	N/A	2	0.5	0.026	11.8	83	83	96	SCR	90	$3,000 to $8,500[3]
Natural Gas - Fired IC Engines- Rich Burn	150 to 300	N/A		0.5	0.022	10.0	83		95	SNCR	80 -90	$1,000 to $7,400[3]
	>250	N/A					83			SNCR	80 -90	$1,000 to $7,400[3]
	>300	N/A	2	0.5	0.022	10.0	83	80	95	SNCR	80 -90	$1,000 to $7,400[3]

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] Alternative Control Technique Document, Stationary Reciprocating Engines, EPA, pp. 2-46 and 2-51.

[4] Cost-effectiveness from Alternative Control Techniques Document, Internal Combustion NOx, EPA 453/R-93-032, March 3, 1997 Page 6-60.

[5] Status Report on NOx Controls, Technologies & Cost Effectiveness, Northeast States for Coordinated Air Use Management, December 2000.

[5] Requires 82 percent reduction in emissions by sources emitting over 1 ton per day of NOx by 2007. No equipment application specified, however, 150 MMBtu/hr firing rate at 42 ppm would result in 328 tons per year.

Emission Control Technology Assessment-Louisiana

Equipment Type	Size Range (MW)	Louisiana Emission Limit (lb/MMBtu)	Typical Texas Emission Limit	Most Stringent Texas Emission Limit (lb/MMBtu)	Uncontrolled Emissions[1] (lb/MMBtu)	Emission Reduction Required by Louisiana Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas Fired Turbines	<1	N/A		0.26	0.32	0		19	DLNC	60 - 70	$154 to $1,060[4]
	> 5 to 10	0.24	0.15	0.15	0.32	25	53	53	LNB	84	$1,403[3]
	>10	0.16	0.15	0.032	0.32	50	53	90	SCR	90	$3,580 to $10,800[4]

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] AirControlNET, Documentation Report v.3.2, September 2003, E.H. Pechan & Associates, Inc..

[4] Alternative Control Techniques Document, NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993 pages 2-31 to 2-34.

Equipment Type	Size Range (hp)	Louisiana Emission Limit (g/hp-hr)	Typical Texas Emission Limit (g/hp-hr)	Most Stringent Texas Emission Limit (g/hp-hr)	Uncontrolled Emissions[1] (lb/hp-hr)	Uncontrolled Emissions[1] (gm/hp-hr)	Emission Reduction Required by Louisiana Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas -Fired IC Engines-Lean Burn, Case 1	150 to 320	10		0.5	0.026	11.8	15		96	Combustion Modifications	70 - 80	$400 to $1,200[4]
	>320	4	2	0.5	0.026	11.8	66	83	96	Combustion Modifications	70 - 80	$245 to $460[5]
Natural Gas -Fired IC Engines-Lean Burn Case 2	150 to 320	10		0.5	0.026	11.8	15		96	SCR	90	$12,000 to $35,000[3]
	>320	4	2	0.5	0.026	11.8	66	83	96	SCR	90	$3,000 to $8,500[3]
Natural Gas -Fired IC Engines-Rich	150 to 300	2		0.5	0.022	10.0	80		95	SNCR	80 -90	$1,000 to $7,400[3]

Equipment Type	Size Range (hp)	Louisiana Emission Limit (g/hp-hr)	Typical Texas Emission Limit (g/hp-hr)	Most Stringent Texas Emission Limit (g/hp-hr)	Uncontrolled Emissions[1] (lb/hp-hr)	Uncontrolled Emissions[1] (gm/hp-hr)	Emission Reduction Required by Louisiana Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Burn												
	>300	2	2	0.5	0.022	10.0	80	80	95	SNCR	81 -90	$1,000 to $7,400[3]

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] Alternative Control Technique Document, Stationary Reciprocating Engines, EPA, pp. 2-46 and 2-51.

[4] Cost-effectiveness from Alternative Control Techniques Document, Internal Combustion NOx, EPA 453/R-93-032, March 3, 1997 Page 6-60.

[5] Status Report on NOx Controls, Technologies & Cost Effectiveness, Northeast States for Coordinated Air Use Management, December 2000.

Equipment Type	Size Range MMBtu/hr	Louisiana Emission Limit (lb/MMBtu)	Typical Texas Emission Limit (lb/MMBtu)	Most Stringent Texas Emission Limit (lb/MMBtu)	Uncontrolled Emissions[1] ($lb/MMft^3$)	Uncontrolled Emissions[1] (lb/MMBtu)	Emission Reduction Required by Louisiana Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas-Fired Industrial Boilers	>40 - 80	0.2	0.1	0.1	140	0.14	0	29	29	SCR	50 - 80[3]	$4,830 to $6,880[4]
	>80	0.1	0.1	0.1	140	0.14	29	29	29	SCR	50 - 80[3]	$3,040 to $5,350[4]
	>40 - 80	0.2	0.1	0.1	140	0.14	0	29	29	SNCR	50 - 70[3]	$960 to $1,450[4]
	>80	0.1	0.1	0.1	140	0.14	29	29	29	SNCR	50 - 70[3]	$960 to $1,450[4]

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] Emission Factor from Alternative control Techniques (ACT) Document, NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers, March 1994 Table Table 5-12

[4] Emission Factor from Alternative control Techniques (ACT) Document, NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers, March 1994 Table Table 6-6 and 6-7

Equipment Type	Size Range MMBtu/hr	Louisiana Emission Limit (lb/MMBtu)	Typical Texas Emission Limit (lb/MMBtu)	Most Stringent Texas Emission Limit (lb/MMBtu)	Uncontrolled Emissions[1] (lb/MMft^3)	Uncontrolled Emissions[1] (lb/MMBtu)	Emission Reduction Required by Louisiana Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas-Fired Process Heaters and Furnaces	>40 - 80	0.18	0.08	0.08	140	0.14	0	43	43	SNCR	50 -60	$2,130 to $13,500[3]
	>80	0.08	0.08	0.08	140	0.14	43	43	43	SNCR	50 -60	$2,130 to $13,500[3]

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] Emission Factor from Alternative control Techniques (ACT) Document, NOx Emissions from Process Heaters (Revised), EPA 453/R-93-034, September 1993 Table 6-9.

Emission Control Technology Assessment-Oklahoma

Equipment Type	Size Range MW	Oklahoma Emission Limit[5] (lb/MMBtu)	Typical Texas Emission Limit	Most Stringent Texas Emission Limit (lb/MMBtu)	Uncontrolled Emissions[1] (lb/MMBtu)	Emission Reduction Required by Oklahoma Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas Fired Turbines	<1	U/C	U/C	0.26	0.32	0	0	19	DLNC	60 - 70	$154 to $1,060[4]
	> 5 to 10	U/C	0.15	0.15	0.32	0	53	53	LNB	84	$1,403[3]
	>10	0.2	0.15	0.032	0.32	38	53	90	SCR	90	$3,580 to $10,800[4]

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] AirControlNET, Documentation Report v.3.2, September 2003, E.H. Pechan & Associates, Inc..

[4] Alternative Control Techniques Document, NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993 pages 2-31 to 2-34

[5] Size Cutoff for Oklahoma is actually > 50 MMBtu/hr or approximately 14.7 MW

Equipment Type	Size Range MMBtu/hr	Oklahoma Emission Limit[6] (g/hp-hr)	Typical Texas Emission Limit (g/hp-hr)	Most Stringent Texas Emission Limit (g/hp-hr)	Uncontrolled Emissions[1] (lb/hp-hr)	Uncontrolled Emissions[1] (gm/hp-hr)	Emission Reduction Required by Oklahoma Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas -Fired IC Engines-Lean Burn	>50	0.5			0.026	11.8	96			SCR	90	$12,000 to $35,000[3]
	150 to 320	0.5		0.5	0.026	11.8	96		96	SCR	90	$3,000 to $8,500[3]
	>320	0.5	2	0.5	0.026	11.8	96	83	96	SCR	90	$3,000 to $8,500[3]
Natural Gas -Fired IC Engines-Rich Burn	150 to 300	0.5		0.5	0.022	10.0	95		95	SNCR	80 -90	$1,000 to $7,400[3]
	>300	0.5	2	0.5	0.022	10.0	95	80	95	SNCR	81 -90	$1,000 to $7,400[3]

Equipment Type	Size Range MMBtu/hr	Oklahoma Emission Limit[6] (g/hp-hr)	Typical Texas Emission Limit (g/hp-hr)	Most Stringent Texas Emission Limit (g/hp-hr)	Uncontrolled Emissions[1] (lb/hp-hr)	Uncontrolled Emissions[1] (gm/hp-hr)	Emission Reduction Required by Oklahoma Regulation (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] Alternative Control Technique Document, Stationary Reciprocating Engines, EPA, pp. 2-46 and 2-51.

[4] Cost-effectiveness from Alternative Control Techniques Document, Internal Combustion NOx, EPA 453/R-93-032, March 3, 1997 Page 6-60.

[5] Status Report on NOx Controls, Technologies & Cost Effectiveness, Northeast States for Coordinated Air Use Management, December 2000.

[6] Actual Emission limit for Oklahoma is 0.2 lb/MMBtu or approximately 0.5 g/hp-hr.

Emission Control Technology Assessment-Tennessee

Equipment Type	Size Range MW	Tennessee Emission Limit[5] (lb/MMBtu)	Typical Texas Emission Limit (lb/MMBtu)	Most Stringent Texas Emission Limit (lb/MMBtu)	Uncontrolled Emissions[1] (lb/MMBtu)	Emission Reduction Required by Tennessee Regulation[5] (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas Fired Turbines	<1	U/C	U/C	0.26	0.32	0	0	19	DLNC	60 - 70	$154 to $1,060[4]
	> 5 to 10	U/C	0.15	0.15	0.32	0	53	53	LNB	84	$1,403[3]
	>10	U/C	0.15	0.032	0.32	0	53	90	SCR	90	$3,580 to $10,800[4]
	>50	N/A	0.15	0.032	0.32	53	53	90	LNB	84	$1,403[3]
	>75	N/A	0.15	0.032	0.32	80 to 90	53	90	SCR	90	$3,580 to $10,800[4]

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] AirControlNET, Documentation Report v.3.2, September 2003, E.H. Pechan & Associates, Inc..

[4] Alternative Control Techniques Document, NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993 pages 2-31 to 2-34.

[5] Requires RACT for sources that emit greater than 100 Tons per year. Emission limit calculated based on 42 ppm burning natural gas. Percent reduction for greater than 50 MW calculated at 0.15 lb/MMBtu.

Equipment Type	Size Range MMBtu/hr	Tennessee Emission Limit[6] (g/hp-hr)	Typical Texas Emission Limit (g/hp-hr)	Most Stringent Texas Emission Limit (g/hp-hr)	Uncontrolled Emissions[1] (lb/hp-hr)	Uncontrolled Emissions[1] (gm/hp-hr)	Emission Reduction Required by Tennessee Regulation[5] (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Natural Gas - Fired IC Engines- Lean Burn	>50	N/C			0.026	11.8	0			SCR	90	$12,000 to $35,000[3]
	150 to 320	0.5		0.5	0.026	11.8	96		96	SCR	90	$3,000 to $8,500[3]
	>250	N/A					80 to 90			SCR	90	$3,000 to $8,500[3]
	>320	N/A	2	0.5	0.026	11.8	80 to 90	83	96	SCR	90	$3,000 to $8,500[3]
Natural Gas -	150 to 300	0.5		0.5	0.022	10.0	95		95	SNCR	80 -90	$1,000 to $7,400[3]

Equipment Type	Size Range MMBtu/hr	Tennessee Emission Limit[6] (g/hp-hr)	Typical Texas Emission Limit (g/hp-hr)	Most Stringent Texas Emission Limit (g/hp-hr)	Uncontrolled Emissions[1] (lb/hp-hr)	Uncontrolled Emissions[1] (gm/hp-hr)	Emission Reduction Required by Tennessee Regulation[5] (per cent)	Emission Reduction Required by Typical Texas Regulation (per cent)	Emission Reduction Required by Most Stringent Texas Regulation (per cent)	Available Control Technology	Emission Reduction Potential (per cent)	Cost-Effectitveness[2] ($/ton of NOx Reduced)
Fired IC Engines-Rich Burn												
	>250	N/A					80 to 90			SNCR	80 -90	$1,000 to $7,400[3]
	>300	N/A	2	0.5	0.022	10.0	80 to 90	80	95	SNCR	80 -90	$1,000 to $7,400[3]

[1] Emission Factor from Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, Fifth Edition, January, 1995, revised, April 2000.

[2] Cost-effectiveness represented by ranges reflects the range of capacity factors for equipment which is a factor of how much the unit is operated.

[3] Alternative Control Technique Document, Stationary Reciprocating Engines, EPA, pp. 2-46 and 2-51.

[4] Cost-effectiveness from Alternative Control Techniques Document, Internal Combustion NOx, EPA 453/R-93-032, March 3, 1997 Page 6-60.

[5] Status Report on NOx Controls, Technologies & Cost Effectiveness, Northeast States for Coordinated Air Use Management, December 2000.

[5] Requires RACT for sources that emit greater than 100 Tons per year. Emission calculation based on 43 ppm and 150 MMBtu/hr unit. For sources >250 MMBtu/hr sources require 80 to 90 percent control.

Appendix G

Compendium of All Major Non-EGU Point Sources of NOx in the Study Area
(Emissions, Source Identifications, Locations, etc.)

Table G-1. Non-EGU Point Sources in Alabama Emitting > 10 tpd NOx in 1999 NEI.

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 2621 - Paper Mills, Exc Building Paper		**11,522**	**10,511**
Alliance Forest Products, Coosa Pines	Talladega	3,938	3,173
International Paper Co., Siebert Station	Mobile	3,929	4,080
International Paper Co., Courtland Mill[1]	Lawrence	3,655	3,258
SIC 4922 - Natural Gas Transmission		**16,373**	**2,608**
Transcontinental Gas Pipe Line	Randolph	8,382	1,330
Transcontinental Gas Pipe Line	Marengo	7,991	1,278

[1]Facility with matching FacID in 2010 is named Champion International.

Table G-2. Non-EGU Point Sources in Arkansas Emitting > 1.5 tpd NOx in 1999 NEI.

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 2611 - Pulp Mills		**7,530**	**2,505**
Georgia-Pacific, Ashdown Operations	Little River	6,314	1,742
International Paper Co., Camden Mill	Ouachita	1,216	763
SIC 2621 - Paper Mills, Exc Building Paper		**10,553**	**2,726**
International Paper Co.	Jefferson	10,553	2,726
SIC 2631 - Paperboard Mills		**620**	**1,020**
Green Bay Packaging, Ark Kraft Div.	Conway	620	1,020
SIC 2819 - Industrial Inorganic Chemicals, NEC		**2,571**	**0**
El Dorado Chemical Co.	Union	2,571	n/m
SIC 2869 - Industrial Organic Chemicals		**929**	**3,508**
Eastman Chemical Co., Ark Eastman Div	Independence	929	3,508
SIC 2911 - Petroleum Refining		**1,862**	**0**
Lion Oil Co.	Union	1,862	n/m
SIC 3241 - Cement, Hydraulic		**691**	**788**
Holnam, Inc	Howard	691	788
SIC 3312 - Blast Furnaces & Steel Mills		**918**	**0**
Nucor-Yamato Steel	Mississippi	918	n/m
SIC 4922 - Natural Gas Transmission		**14,037**	**1,208**
Natural Gas Pipeline Co, Station 305	Miller	2,932	n/m
Noram-Dunn Compressor Station	Logan	2,775	n/m
Ngc-Compressor Station 306	Hot Spring	2,469	n/m
Natural Gas Pipeline Co. of America	Randolph	1,823	1,208
Mrt-Fountain Hill Compressor Station	Ashley	1,089	n/m
Noram-Walker Compressor Station	Franklin	906	n/m
Reliant Energy, Hobbs Comp. Station	Sebastian	762	n/m
Mrt-Carlisle Compressor Station	Lonoke	713	n/m
Reliant Energy, Webb City Comp Station	Franklin	568	n/m

Table G-2. Non-EGU Point Sources in Arkansas Emitting > 1.5 tpd NOx in 1999 NEI. (cont.)

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 4953 - Waste Incineration		**1,113**	**0**
Ensco	Union	1,113	n/m

n/m = no match.

Table G-3. Non-EGU Point Sources in Kentucky Emitting > 10 tpd NOx in 1999 NEI.

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 2911 - Petroleum Refining		**4,395**	**5,644**
Marathon Ashland Petroleum	Boyd	4,395	5,644
SIC 3241 - Cement, Hydraulic		**4,661**	**3,456**
Kosmos Cement Company	Jefferson	4,661	3,456

Table G-4. Non-EGU Point Sources in Louisiana Emitting > 1.5 tpd NOx in 1999 NEI.

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 1311 - Crude Petroleum & Natural Gas		**6,765**	**6,450**
Energy Partners Ltd, E Bay Cntrl	Plaquemines	4,878	4,759
Texaco E & P Inc, C B Chandeleur	Terrebonne	725	554
Williams Field Srvcs, Cameron Meadows	Cameron	593	487
Phillips Petroleum Co., Lk Washington	Plaquemines	569	649
SIC 1321 - Natural Gas Liquids		**5,094**	**5,900**
Gulf South Pipeline Co Lp, Bistineau	Bienville	1,159	2,401
Dynegy Midstream Svc Lp, Yscloskey	St. Bernard	919	832
Duke Energy Fld Srvcs Lp, Minden[1]	Webster	669	481
Enterprise Gas Proc Llc, N Terrebonne	Terrebonne	615	559
Western Gas Resources Inc, Toca	St. Bernard	590	758
Exxonmobil Prod Co, Blue Water	Acadia	589	518
Reliant Energy Fld Srvcs, Sligo[2]	Bossier	553	352
SIC 2611 - Pulp Mills		**2,924**	**3,810**
Riverwood International-Plnt 31	Ouachita	1,957	2,347
Crown Paper Co, St. Francisville Fac	West Feliciana	967	1,463
SIC 2621 - Paper Mills, Exc Building Paper		**8,825**	**9,998**
International Paper Co, Louisiana Mill	Morehouse	2,397	2,728
Boise Cascade Corp, Deridder Mill	Beauregard	2,171	2,613
Gaylord Container Corporation	Washington	1,664	1,502
Willamette Ind, Red River Mill	Natchitoches	1,304	1,422
Georgia Pacific, Pt Hudson Operations	East Baton Rouge	1,289	1,732
SIC 2631 - Paperboard Mills		**4,341**	**4,962**
Stone Container Corp., Hodge Inc	Jackson	1,753	2,837
International Paper, Mansfield Mill	De Soto	1,392	729
International Paper Co, Pineville Mill	Rapides	1,196	1,396

Table G-4. Non-EGU Point Sources in Louisiana Emitting > 1.5 tpd NOx in 1999 NEI. (cont.)

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 2813 - Industrial Gases		**2,863**	**3,567**
Borden Chem & Plastics Oper,, Geismar	Ascension	2,117	2,532
Air Products & Chemicals,Inc, No Fac	Orleans	746	1,035
SIC 2819 - Industrial Inorganic Chemicals, NEC		**3,137**	**5,739**
Kaiser Aluminum & Chem. Corp, Gramercy	St. James	1,111	3,301
W. R. Grace & Co	Calcasieu	775	703
Imc Phosphates Co, Faustina Plnt	St. James	664	1,039
Ormet Corp, Alumina Plant	Ascension	587	696
SIC 2821 - Plastics Materials And Resins		**11,655**	**16,678**
Dow Chemical Co, La Division	Iberville	8,733	13,365
Cytec Industries,Inc, Fortier Plnt	Jefferson	1,584	2,104
Georgia Gulf Chem & Vinyls, Plaquemine	Iberville	1,338	1,209
SIC 2824 - Organic Fibers, Noncellulosic		**1,024**	**0**
EI Dupont De Nemours & Co, Pontchartrain	St. John the Baptist	1,024	n/m
SIC 2865 - Cyclic Crudes And Intermediate		**648**	**0**
Lyondell Chem Co, Lake Charles Plnt	Calcasieu	648	n/m
SIC 2869 - Industrial Organic Chemicals		**36,896**	**17,709**
Shell Chemical, Norco Chem Plt East Site	St. Charles	11,792	n/m
Ppg Industries,Inc.	Calcasieu	8,761	1,748
Union Carbide, Taft & Star	St. Charles	5,980	3,201
Exxonmobil Chem Co, Br Chem Plt	East Baton Rouge	2,692	2,766
Condea Vista Co, Main Plant	Calcasieu	1,830	2,191
Basf Corporation, Geismar Site	Ascension	1,363	1,464
Westlake Petrochem. Corp, Ethylene Mfg Cmplx	Calcasieu	1,144	889
Shell Chemical Lp, Geismar Plnt	Ascension	729	704
Williams Olefins Llc, Geismar[3]	Ascension	726	878
Cosmar Company	Iberville	700	1,253
Formosa Plastics Corporation, La	East Baton Rouge	618	684
Vulcan Chemicals	Ascension	561	1,930
SIC 2873 - Nitrogenous Fertilizers		**9,809**	**14,200**
Cf Industries, Inc.	Ascension	2,986	3,985
Koch Nitrogen Company	Ouachita	2,191	2,924
Triad Nitrogen Llc	Ascension	1,690	1,968
Pcs Nitrogen Fertilizer,L.P., Geismar	Ascension	1,385	2,842
Triad Nitrogen, Inc, Ampro	Ascension	971	1,537
Farmland Industries, Inc.	Grant	586	944
SIC 2895 - Carbon Black		**5,390**	**2,109**
Columbian Chem Co, North Bend	St. Mary	3,521	604
Cabot Corporation, Canal Plant	St. Mary	1,113	1,297
Cabot Corporation, Ville Platte Plnt	Evangeline	756	209

Table G-4. Non-EGU Point Sources in Louisiana Emitting > 1.5 tpd NOx in 1999 NEI. (cont.)

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 2911 - Petroleum Refining		**31,471**	**54,025**
Citgo Petroleum Corp, Lake Charles	Calcasieu	7,974	12,390
Tosco Refining Co, Alliance Refinery	Plaquemines	5,041	8,776
Exxonmobil Ref & Supply Co, B R Refinery	East Baton Rouge	3,496	4,045
Motiva Enterprises Llc, Norco Refinery[4]	St. Charles	3,027	14,429
Marathon Ashland Petroleum, Garyville	St. John the Baptist	2,539	2,637
Mobil Oil Corp, Chalmette Refinery	St. Bernard	2,392	3,952
Motiva Enterprises,Llc, Convent[5]	St. James	1,992	2,325
Conoco Inc, Lake Charles Refinery	Calcasieu	1,562	1,847
Murphy Oil Usa, Inc., Meraux Refinery	St. Bernard	1,240	2,312
Orion Refining Corp	St. Charles	1,175	n/m
Placid Refining Co Llc, Pt Allen	West Baton Rouge	1,033	1,312
SIC 2999 - Petroleum And Coal Products, Nec		**779**	**928**
Venture Coke Co, Lk Charles	Calcasieu	779	928
SIC 3221 - Glass Containers		**669**	**795**
Ball Foster Glass Container Co.,L.L.C.	Lincoln	669	795
SIC 3229 - Pressed And Blown Glass, NEC		**680**	**968**
Libbey Glass, Inc.	Caddo	680	968
SIC 3295 - Minerals, Ground Or Treated		**1,086**	**398**
Big River Industries, Inc.	Pointe Coupee	1,086	398
SIC 4922 - Natural Gas Transmission		**39,488**	**55,079**
Transcontinental Gas Pipe Line, 60	East Feliciana	5,133	5,439
Transcontinental Gas Pipe Line, 65	St. Helena	2,477	n/m
Southern Natural Gas, Toca Comp Stn	St. Bernard	2,282	3,295
Tennessee Gas Pipeline-Station 47	Ouachita	2,271	4,436
Transcontinental Gas Pipe Line, 45	Beauregard	1,802	2,514
Florida Gas Transmission Co, Eunice Cs 7	Acadia	1,612	2,009
Florida Gas Trans. Co., Franklinton C.S.	Washington	1,543	1,307
Tennessee Gas Pipeline-Station 527	Plaquemines	1,483	2,174
Southern Natural Gas, Franlinton Stn	Washington	1,479	2,870
Trunkline Gas Co, Epps Comp Station	West Carroll	1,275	1,943
Anr Pipeline Co, Patterson Station	St. Mary	1,166	4,363
Columbia Gulf Transmission Co, Rayne	Acadia	1,163	1,389
Transcontinental Gas Pipe Line, 54	St. Landry	1,150	2,221
Columbia Gulf Transmission Co, Delhi	Richland	1,108	1,801
Southern Natural Gas, Bear Creek Stn	Bienville	1,107	591
Gulf South Pipeline Co, Montpelier	St. Helena	1,031	n/m
Williams Field Services, C.S.#63	St. James	1,020	n/m
Southern Natural Gas, Olga Comp Stn	Plaquemines	965	1,654
Texas Gas Trans Corp, Columbia	Caldwell	917	520
Chevron Usa Inc, W Bay Compress Stn	Plaquemines	861	857
Florida Gas Trans. Co, Zachary CS	East Baton Rouge	816	1,038

Table G-4. Non-EGU Point Sources in Louisiana Emitting > 1.5 tpd NOx in 1999 NEI. (cont.)

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 4922 - Natural Gas Transmission		**39,488**	**55,079**
Columbia Gulf Transmission Co, Alex	Rapides	812	1,403
Sea Robin Pipeline Co, Erath Comp Stn.	Vermilion	765	1,742
Anr Pipeline Co, Delhi Comp Station	Richland	727	933
Anr Pipeline Co, Jena Comp Station	La Salle	717	1,700
Miss River Transmission, Perryville CS	Ouachita	710	515
Miss River Transmission, Unionville CS	Lincoln	664	506
Trunkline Gas Co, Pollock Station	Grant	642	1,321
Tennessee Gas Pipeline-Stn 40 & 500	Natchitoches	612	1,625
Williams Field Services, C.S. #62	Terrebonne	600	3,927
Gulf South Pipeline Co, Clarence	Natchitoches	578	988
SIC 4925 - Gas Production/Distribution		**1,022**	**1,286**
El Paso Fld Srvcs Co, Eunice Extraction	Acadia	1,022	1,286
SIC 4941 - Water Supply		**1,282**	**4**
Sewerage & Water Bd Of N.O.	Orleans	1,282	4

n/m = no match.
[1]Facility with matching FacID in 2010 is named Pan Energy/Minden.
[2]Facility with matching FacID in 2010 is named NGC-WER/Sligo.
[3]Facility with matching FacID in 2010 is named Union TX Petrochem..
[4]Facility with matching FacID in 2010 is named Shell Oil - Norco East.
[5]Facility with matching FacID in 2010 is named Star Enterprise.

Table G-5. Non-EGU Point Sources in Mississippi Emitting > 5 tpd NOx in 1999 NEI.

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 2611 - Pulp Mills		**2,149**	**1,164**
Georgia Pacific Co Leaf River Products	Perry	2,149	1,164
SIC 2816 - Inorganic Pigments		**3,059**	**755**
E I Dupont De Nemours And Co	Harrison	3,059	755
SIC 2873 - Nitrogenous Fertilizers		**3,596**	**31,783**
Misschem Nitrogen Llc	Yazoo	3,596	31,783
SIC 2911 - Petroleum Refining		**4,749**	**0**
Chevron Usa	Jackson	4,749	n/m
SIC 4922 - Natural Gas Transmission		**46,403**	**1,842**
Transcontinental Gas Pipe Line	Jones	12,533	n/m
Trunkline Gas Co	Tate	4,789	n/m
Texas Eastern Transmission Corp	Attala	4,359	n/m
Tennessee Gas Pipeline Co #54	Washington	3,929	n/m
Texas Eastern Transmission Corp	Jefferson	3,510	n/m
Anr Pipeline Co	Washington	3,114	n/m
Tennessee Gas Pipeline Co	Hancock	3,016	n/m
Tennessee Gas Pipeline	Lowndes	2,807	n/m
Trunkline Gas Co	Bolivar	2,306	n/m

Table G-5. Non-EGU Point Sources in Mississippi Emitting > 5 tpd NOx in 1999 NEI. (cont.)

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 4922 - Natural Gas Transmission		**46,403**	**1,842**
Columbia Gulf Transmission Co	Humphreys	2,182	1,842
Tennessee Gas Pipeline Co, #538	Jasper	2,011	n/m
Tennessee Gas Pipeline Co	Forrest	1,847	n/m

n/m = no match.

Table G-6. Non-EGU Point Sources in Missouri Emitting > 10 tpd NOx in 1999 NEI.

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 3241 - Cement, Hydraulic		**6,450**	**2,414**
Holnam Inc., Clarksville	Pike	6,450	2,414

Table G-7. Non-EGU Point Sources in Oklahoma Emitting > 1.5 tpd NOx in 1999 NEI.

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 1311 - Crude Petroleum & Natural Gas		**857**	**896**
Texaco Exploration & Production, Inc.	Garvin	857	896
SIC 1321 - Natural Gas Liquids		**11,276**	**10,379**
Spectrum Field Services[1]	Stephens	2,084	1,921
Northern Natural Gas Co.	Beaver	1,689	1,968
Texaco Exploration & Production, Inc.	Garvin	1,585	1,680
Timberland Gathering & Processing Co.	Texas	1,072	780
Oneok Field Services Co.[2]	Garfield	957	1,016
Gpm Gas Company Llc.[3]	Woodward	943	735
Carrera Gas Compranies, Llc[4]	Marshall	895	531
Colorado Interstate Gas	Beaver	707	612
Duke Energy	Grady	694	490
Cms Field Services Inc.[5]	Logan	649	645
SIC 2621 - Paper Mills, Exc Building Paper		**1,461**	**1,736**
Ft. Howard Corporation	Muskogee	1,461	1,736
SIC 2631 - Paperboard Mills		**2,637**	**3,373**
Weyerhaeuser Company	McCurtain	2,637	3,373
SIC 2873 - Nitrogenous Fertilizers		**1,556**	**2,292**
Terra Nitrogen, Limited Partnership	Rogers	1,556	2,292
Farmland Industries, Inc.	Garfield	1,360	546
Terra Nitrogen, Limited Partnership	Woodward	643	807

Table G-7. Non-EGU Point Sources in Oklahoma Emitting > 1.5 tpd NOx in 1999 NEI. (cont.)

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 2911 - Petroleum Refining		**3,071**	**5,395**
Conoco Inc.	Kay	3,071	5,395
Sinclair Oil Corporation	Tulsa	1,626	3,139
Wynnewood Refining Company	Garvin	1,254	1,215
Sun Company Inc.	Tulsa	598	1,310
SIC 2999 - Petroleum And Coal Products, Nec		**657**	**267**
Great Lakes Carbon	Garfield	657	267
SIC 3211 - Flat Glass		**1,750**	**2,019**
Visteon[6]	Tulsa	1,750	2,019
SIC 3221 - Glass Containers		**1,069**	**1,068**
Anchor Glass Container Corporation	Okmulgee	1,069	1,068
Saint-Gobain Containers, L.L.C.[7]	Creek	901	603
SIC 3241 - Cement, Hydraulic		**3,437**	**2,282**
Holnam, Inc.	Pontotoc	3,437	2,282
Blue Circle Cement	Rogers	1,840	2,002
Lone Star Industries Inc.	Mayes	979	1,173
SIC 4922 - Natural Gas Transmission		**1,499**	**1,062**
Anr Pipeline Company	Woodward	1,499	1,062
Duke Energy	Stephens	1,187	1,310
Duke Energy	Carter	891	673
Panhandle Eastern Pipeline Co.	Woods	876	1,320
Duke Energy	Dewey	718	393
Williams Field Services Co.	Texas	698	746
Oklahoma Gas Processing, Inc.	Garvin	600	630
Reliant Energy Gas Transmission Co.[8]	Latimer	560	1,087
SIC 4953 - Waste Incineration		**1,071**	**1,111**
Ogden Martin Systems Of Tulsa, Inc.	Tulsa	1,071	1,111

[1]Facility with matching FacID in 2010 is named Texaco Exploration/Velma Gas
[2]Facility with matching FacID in 2010 is named NGC - Warren NG/Rodman
[3]Facility with matching FacID in 2010 is named Amoco Production/Mooreland
[4]Facility with matching FacID in 2010 is named NGC - Warren/Madill
[5]Facility with matching FacID in 2010 is named Heritage Gas/Crescent
[6]Facility with matching FacID in 2010 is named Ford Motor Corp
[7]Facility with matching FacID in 2010 is named Ball-Foster/Sapulpa
[8]Facility with matching FacID in 2010 is named NorAm Gas Trans/Chandler

Table G-8. Non-EGU Point Sources in Tennessee Emitting > 10 tpd NOx in 1999 NEI.

Facility Name/Owner	Location-County	1999 NOx Emissions-tpy	2010 NOx Emissions-tpy
SIC 2611 - Pulp Mills		**6,399**	**3,328**
Bowater Newsprint & Directory, Calhoun	McMinn	6,399	3,328
SIC 2869 - Industrial Organic Chemicals, NEC		**13,343**	**7,804**
Eastman Chemical Company	Sullivan	13,343	7,804